ISSUES PAPER

QLD electricity distribution determinations

Energex and Ergon Energy

2020 to 2025

March 2019

Inquiries about this publication should be addressed to:

Australian Energy Regulator
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Melbourne Vic 3001

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Invitation for submissions

A public forum on the proposals from Energex and Ergon Energy and our issues paper will be held on 9 April 2019 in Brisbane. Interested parties are invited to register their interest in attending the forum by emailing EnergyQueensland2020@aer.gov.au with their name, the business or agency they represent (if relevant) and contact details by 5 April 2019. Forum details provided below:

Location: Pullman Brisbane King George Square, Corner Ann & Roma Streets, BRISBANE
Date: Tuesday, 9 April 2019
Time: 9:00 am – 12:30 pm

Written submissions on the proposals from Energex and Ergon Energy are invited by 16 May 2019.

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

Submissions should be sent to: EnergyQueensland2020@aer.gov.au.

Alternatively, submissions can be sent to:

Warwick Anderson
General Manager, Networks Finance and Reporting
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

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/CCP14	Consumer Challenge Panel, sub-panel 14
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
opex	operating expenditure
PTRM	Post tax revenue model
Qld	Queensland
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 31 January 2019, Energex and Ergon Energy submitted their revenue proposals for the five years commencing 1 July 2020. This issues paper highlights some of the key elements of the two proposals.

The AER has not yet formed a view on the proposals put to us by Energex and Ergon Energy. While we have commenced our review, we have not been able to consider all the materials and evidence that support the claims made by Energex and Ergon Energy. Further, we have not applied all our regulatory tools to test the robustness of the proposals.

A key part of our review is consultation with stakeholders. The purpose in publishing this paper, required under clause 6.9.3(b)(2), is to assist stakeholders by identifying those aspects of the proposals which, after our preliminary review, are likely to be relevant to our assessment of the proposal. Stakeholders can assist our process by providing their views on these aspects. Stakeholders should feel free to comment on any aspect of the regulatory proposals.

In July 2016, the Queensland State Government owned electricity distribution networks, and regional retail electricity business; Energex and Ergon Energy, were merged under the banner of Energy Queensland. Despite the merger, Energy

2 NEL, s. 7.

Queensland will continue to own and operate the networks separately, retaining the Energex and Ergon Energy brands in their respective markets.

According to Clause 6.8.2(e) of the NER, "*If more than one distribution system is owned, controlled or operated by a Distribution Network Service Provider, then, unless the AER otherwise determines, a separate regulatory proposal and a separate tariff structure statement are to be submitted for each distribution system*." Energy Queensland has not requested to provide a single regulatory proposal covering both the Energex and Ergon Energy networks. As a result, separate regulatory proposals and tariff structure statements have been developed and submitted for each distribution network and are discussed in turn in this paper.

However, Ergon Energy has made a separate request to submit a combined regulatory proposal and tariff structure statement covering both the Ergon Energy network and a separate isolated network for Mt Isa-Cloncurry which it owns and operates. We have agreed to this request. This decision is consistent with Clause 6.8.2(e) and our past decisions in relation to Ergon Energy's networks. As a result, Ergon Energy has submitted a single regulatory proposal and tariff structure statement that includes both networks.

1.1 How can you get involved?

A public forum on the proposals will be held in Brisbane on 9 April 2019. As part of this review we're also seeking written submissions from stakeholders on the proposals from Energex and Ergon Energy, 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 (CCP14).[3] The expert members of the CCP help us to make better regulatory decisions by providing input on issues of importance to consumers and bringing consumer perspectives to our processes.

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3 Members of CCP14 are Mark Grenning, Mike Swanston and Louise Benjamin. Member biographies are available on our website: https://www.aer.gov.au/about-us/consumer-challenge-panel.

The table below sets out the key milestones planned for these reviews:

Milestone	Date
Energex and Ergon Energy submitted their proposals	31 January 2019
AER issues paper published	28 March 2019
Public forum on Energex and Ergon Energy proposals	9 April 2019
Submissions on AER's issues paper and Energex and Ergon Energy's proposals due	16 May 2019
AER draft decision to be published	September 2019
Public forum on draft decision	October 2019
Energex and Ergon Energy submit revised proposals	December 2019
Submissions on draft decision and revised proposals due	January 2020
AER final decision to be published	April 2020

Note: Timelines are subject to change.

2 What would these proposals mean for QLD customers?

Energex and Ergon Energy are the electricity distribution network service providers in Queensland (Qld):

- Energex's network serves customers in the south-east corner for Qld.
- Ergon Energy's network serves customers in rural and regional Qld.

Together, these businesses have proposed combined revenues of $13.1 billion ($nominal, smoothed), to be recovered from Qld electricity customers over the five years from 1 July 2020 to 30 June as set out in Table 1).

We set out proposed revenue in nominal dollar terms as these are the total revenues that Energex and Ergon Energy expect to recover from customers after taking into account forecast inflation over the next regulatory control period.

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

($ million)	2020-21	2021-22	2022-23	2023-24	2024-25	Total 2020-25
Energex	1,246.4	1,276.6	1,307.5	1,339.1	1,371.5	6541.2
Ergon Energy	1,241.6	1,271.6	1,302.4	1,333.9	1,366.2	6515.8

Source: AER analysis. Energex, Regulatory proposal PTRM, 19 January 2019; Ergon Energy, Regulatory proposal PTRM, 19 January 2019; AER Final decision PTRMs for 2015-20 regulatory period, as updated post final decision, expected smoothed revenue $nominal (revenue cap).

Table 2 shows the estimated impact that the Energex and Ergon Energy proposal would have on distribution network tariffs over the next five years. These are also set out in nominal terms.

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

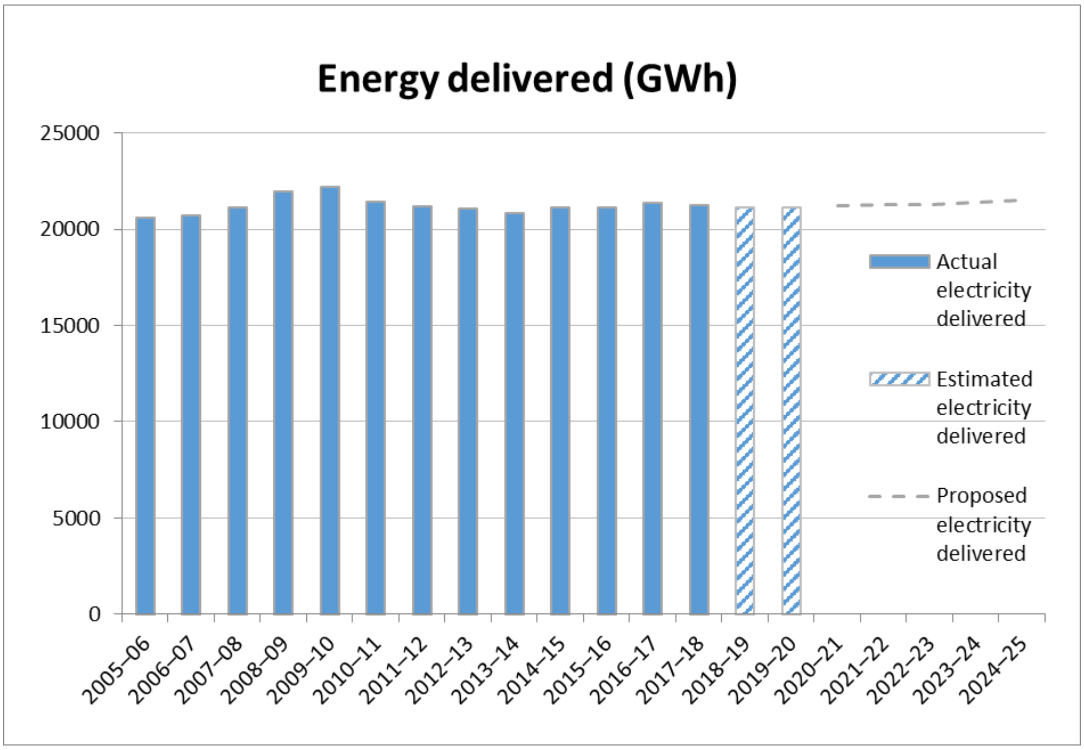
	2020-21	2021-22	2022-23	2023-24	2024-25	Average 2020-25
Energex	–8.3%	2.0%	2.5%	1.7%	1.9%	–0.1%
Ergon Energy	–7.4%	2.2%	2.2%	2.2%	2.2%	0.2%

Source: AER analysis. Energex, Reset RIN section 17.052, 19 January 2019; Ergon Energy, Reset RIN section 17.059, 19 January 2019

Energex and Ergon Energy estimate that there will be a reduction of the distribution network tariff cost component of around 8.3 per cent and 7.4 per cent respectively, of a typical average residential electricity bill from 2019-20 to 2020-21.[4] [5] This reduction in the first year of the next regulatory control period is largely driven by the revenue reduction which is generally referred to by the industry and us as the P0 adjustment. The P0 adjustment is expressed in real terms ($2019-20). Energex and Ergon Energy propose P0 reductions of 10.3 per cent and 9.4 per cent ($, 2019-20), and constant real revenues thereafter (X factor of 0 per cent), respectively.[6]

Under the revenue cap form of control that applies to Energex and Ergon Energy, any difference between forecast and actual energy delivered will impact distribution tariffs: if actual energy delivered is higher than forecast, tariffs will go down (and vice versa). Figure 1 shows the actual energy delivered during the 2015–20 regulatory control period and the forecast proposed by Energex for the next regulatory control period from 2020 to 2025.

Figure 1 Actual and forecast energy delivered by Energex



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4 Energex, Reset RIN section 17.052, 19 January 2019; Ergon Energy, Reset RIN section 17.059, 19 January 2019

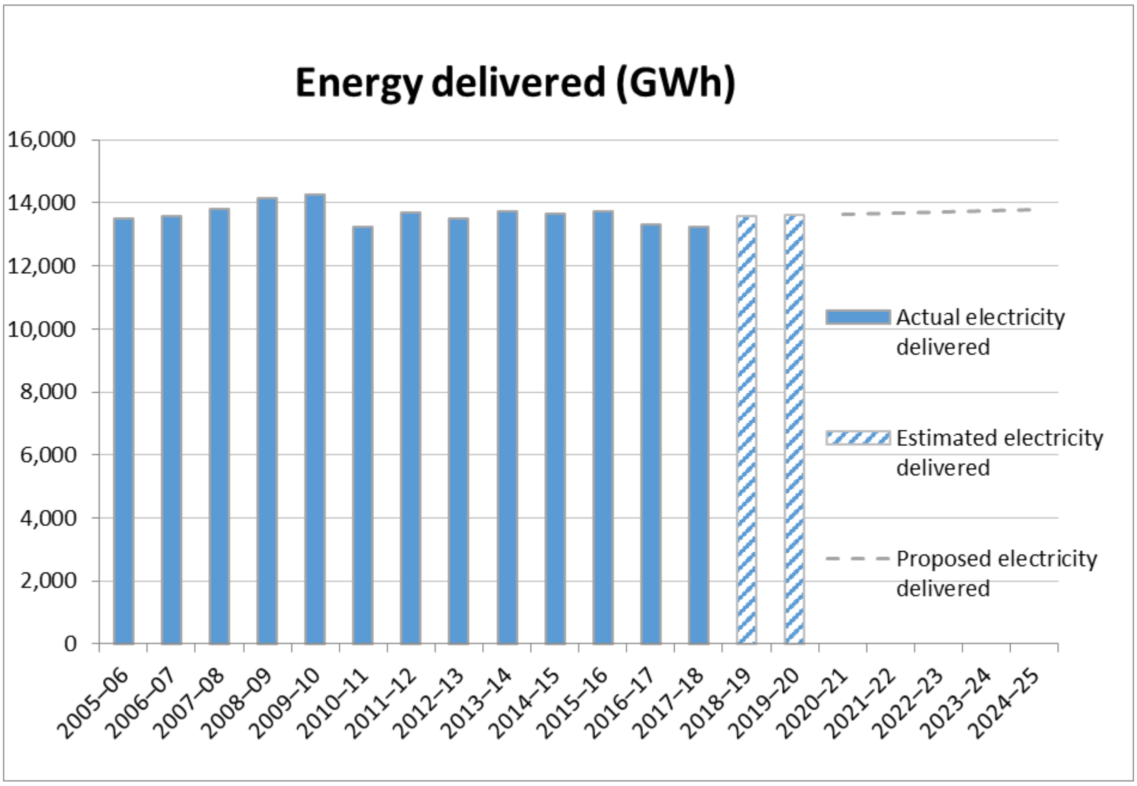
5 EGX 17.052 Indicative Bill Impact RIN template – January 2019. Assumes distribution costs make up 31.5 per cent of a typical residential customer's electricity bill, and 30.0% of a typical small business customer's electricity bill.

6 The P0 adjustment measures the real change in smoothed revenue from 2019–20 to 2020–21. This is different to the change in indicative network tariff from 2019–20 to 2020–21 because the change in indicative network tariff takes into account the change in volumes as well as nominal revenue change. It should also be noted that the P0 adjustment is based on real 2019–20 dollar terms, while the change in indicative network tariff is based on a nominal value comparison which include the impact for annual inflation.

Source: Energex Economic benchmarking RINs; Energex 2020-25 reset RIN.

Figure 2 shows the actual (and forecast) energy delivered for Ergon Energy over the 2015-20 and 2020-25 regulatory periods.

Figure 2 Actual and forecast energy delivered by Ergon



Source: Ergon Economic benchmarking RINs; Ergon Energy 2020-25 reset RIN

The common categories of costs that are typically identified as making up retail electricity prices are wholesale costs (generation), 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 Holding all other bill components constant, Table 3 and Table 4 shows the impacts of the revenue Energex and Ergon Energy is seeking over the 2020–25 regulatory control period on the distribution network tariffs over that period. We provide these in both nominal and real dollars. In Queensland retail prices are subsidised in Ergon Energy's regions and updated based on the changes in Energex's distribution tariffs.[7]

[7] Queensland Competition Authority, Final Determination–Regulated retail electricity prices for 2018–19, May 2018, p.iii

Table 3 Indicative Impact of Energex's proposed 2020–25 revenue on the distribution network tariffs

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	Total 2020-21 to 2024-25
Residential customer							
Regulated tariff ($ nominal)	$504	$462	$472	$484	$492	$501	$2411
Annual change ($ nominal)		-$42	$9	$12	$8	$9	-$3
Regulated tariff ($ real, June 2020)	$504	$452	$450	$450	$447	$445	$2243
Annual change ($ real, June 2020)		-$53	-$2	$0	-$3	-$2	-$60
Small business customer							
Regulated tariff ($ nominal)	$770	$706	$720	$738	$750	$764	$3678
Annual change ($ nominal)		-$64	$14	$18	$13	$14	-$5
Regulated tariff ($ real, June 2020)	$770	$689	$686	$687	$682	$678	$3422
Annual change ($ real, June 2020)		-$81	-$3	$1	-$5	-$4	-$91

Source: Energex, Reset RIN section 17.052, January 2019

Table 4 Indicative Impact of Ergon Energy's proposed 2020–25 revenue on the distribution network tariffs

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	Total 2020-21 to 2024-25
Residential customer							
Regulated tariff ($ nominal)	$504	$467	$477	$487	$498	$509	$2439
Annual change ($ nominal)		-$38	$10	$10	$11	$11	$5
Regulated tariff ($ real, June 2020)	$504	$452	$450	$450	$447	$445	$2243
Annual change ($ real, June 2020)		-$53	-$2	$0	-$3	-$2	-$60
Small business customer							
Regulated tariff ($ nominal)	$770	$712	$728	$744	$760	$777	$3721
Annual change ($ nominal)		-$57	$16	$16	$16	$17	$7
Regulated tariff ($ real, June 2020)	$770	$696	$694	$692	$691	$689	$3462
Annual change ($ real, June 2020)		-$74	-$2	-$2	-$1	-$2	-$81

Source: Ergon Energy, Reset RIN section 17.059, January 2019

2.1 Stakeholder engagement

Energy Queensland set out the customer engagement process, that has been undertaken for Energex and Ergon Energy, in their proposals and which is also available in the Community and Customer Engagement report on its website: talkingenergy.com.au. This engagement has been undertaken in five stages:

- October 2017 to February 2018 — review current insights and identify how customers can help inform future plans
- February 2018 to July 2018 — build capacity to engage, explore views in depth and seek feedback on direction
- September 2018 to October 2018 — engage on draft positions incorporating feedback
- January 2019 to February 2019 — publish Regulatory Proposal and explain how feedback has been incorporated
- March 2019 to December 2019 — engage on issues and end with Revised Proposal and Final Determination

Based on its stakeholder engagement, Energex and Ergon Energy identified that customers and stakeholders generally agreed that they value:

- Safety First
- More affordable electricity
- A secure supply
- A sustainable future

CCP 14 also participated in some of these stakeholder engagement events. CCP 14 responded to Energex's and Ergon Energy's draft plan after observing/participating in Energex and Ergon engagement events. They found the engagement to be well attended and effective.[8]

As part of our assessment, we are particularly interested in hearing from stakeholders:

- how the above value areas reflect stakeholder priorities for these determinations; and
- how well Energex and Ergon Energy have — in the proposal submitted to us for assessment — addressed matters put to Energex and Ergon Energy over the engagement period.

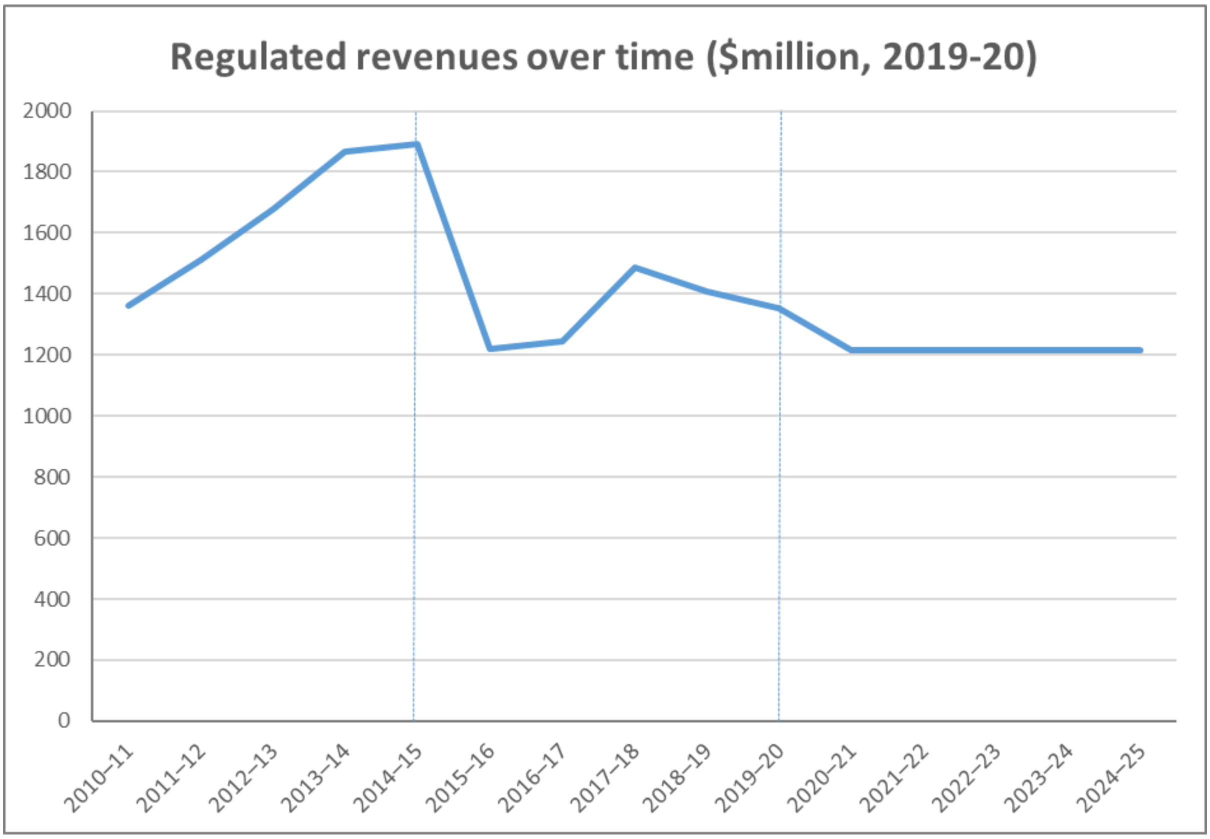
[8] CCP 14, Submission on Energy Queensland's Draft Plan – 25 October 2018. p. 23.

3 What's driving the change in revenue over time

In this chapter we discuss revenue changes in real dollars ($2019–20). This allows for comparisons after taking inflation impacts into account.

Energex's proposal would allow it to recover $6,084.9 million ($2019–20, smoothed) from customers over the 2020–25 regulatory control period. This is a 9.4 per cent decrease from our last decision for 2015–20. Figure 3 shows the AER's approved regulated revenue in the past two regulatory periods from 2010–11 to 2019–20 ($2019–20, smoothed) compared to the forecast revenue proposed by Energex for the 2020–25 regulatory control period.

Figure 3 Energex's regulated revenues over time



Source: AER analysis based on AER Final decision PTRM for 2010-15 and 2015-20 regulatory periods, as updated post final decision; Energex Regulatory Proposal PTRM 2020-25 regulatory period. Smoothed revenues. Total revenue for 2020-25 is $6085 million (2019-20).

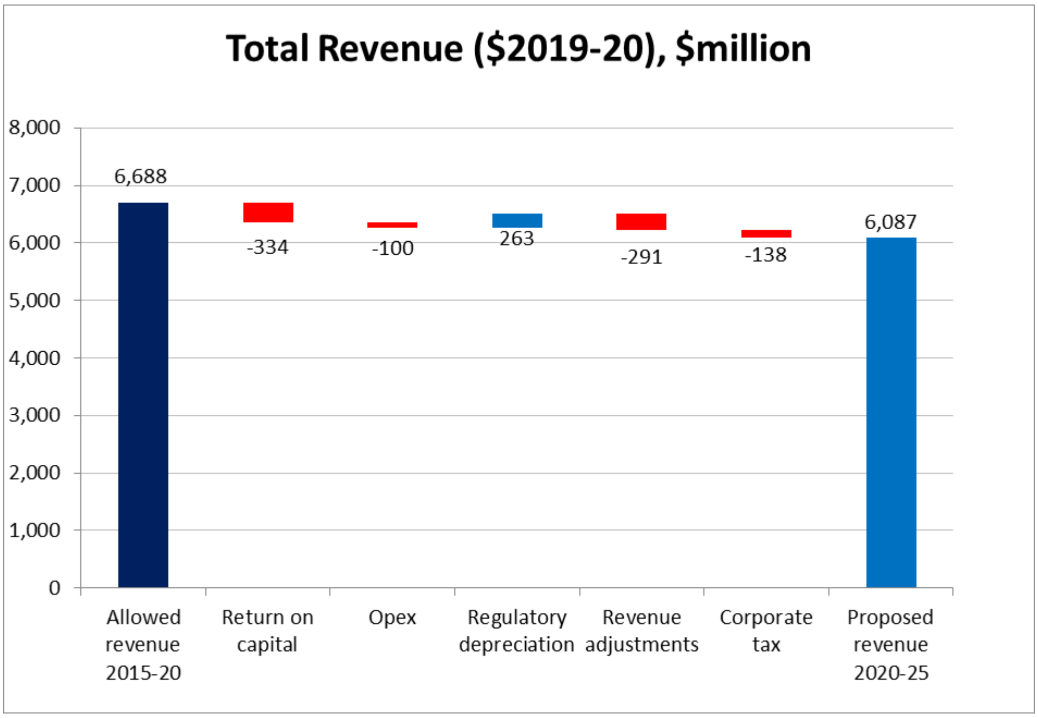
According to the Energex's proposal, these reductions are being driven by a number of factors, including:

- one-off operating efficiencies through the merger of Energex and Ergon Energy into Energy Queensland;

- savings from the capital investment program for 2015-20 which result in a lower than forecast opening RAB[9];
- 1.72 per cent annual productivity improvement;
- Lower financing and tax costs;
- lower forecast capital and operational expenditure in the 2020-25 period than in the previous period; and
- subject to approval of the regulatory proposal, foregoing certain incentive payments (CESS and EBSS) from improved efficiencies.

Energex is proposing to pass these, and other savings gained through increased efficiencies, on to its customers in the form of lower network charges. Figure 4 shows changes in Energex's proposal at the building block level to illustrate what is driving its proposed revenue. The individual drivers, as mentioned above, are discussed further in section 4.

Figure 4 Changes in building blocks: Energex's allowed revenue 2015–20 to forecast revenue 2020–25 ($million, 2019/20 – unsmoothed)



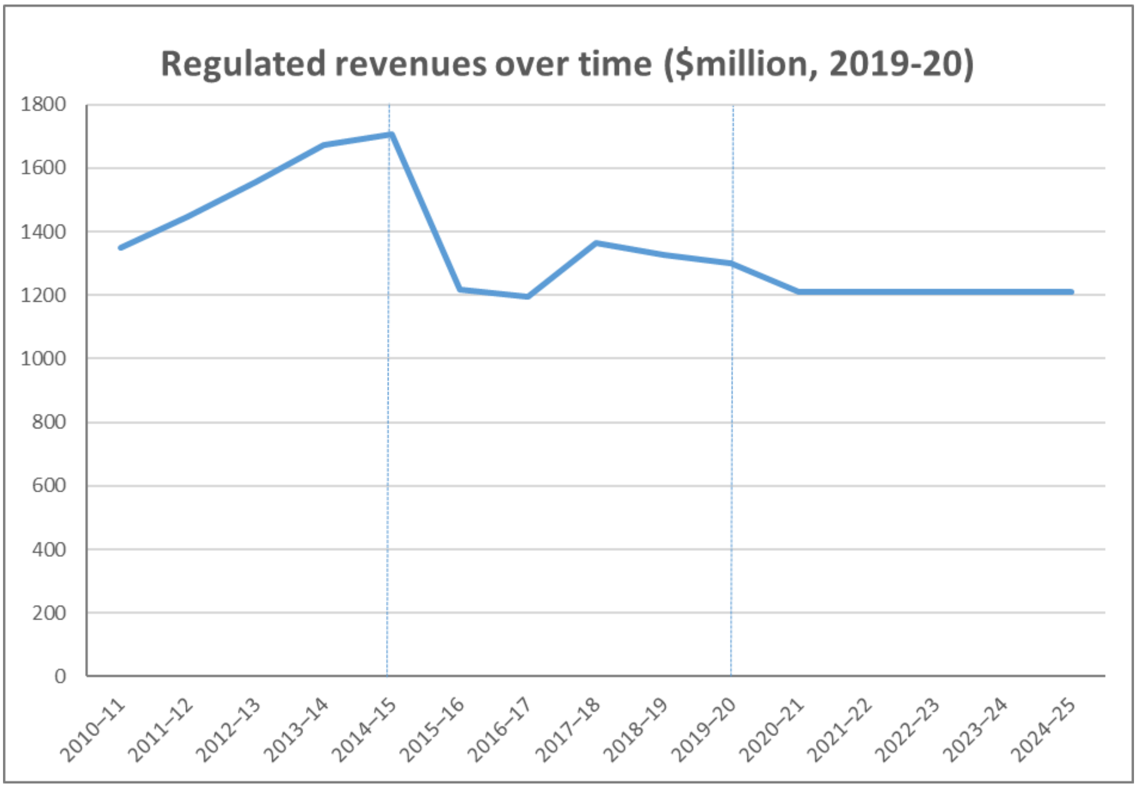
Source: AER analysis based on AER Final decision PTRM for 2015-20 regulatory period, as updated post final decision; Energex Regulatory Proposal PTRM 2020-25 regulatory period.

Ergon Energy's proposal would allow it to recover $6,061.3 million ($2019/20, smoothed) from customers over the 2020–25 regulatory control period. This is a 5.4

[9] From Energex final decision, AER Final decision Energex distribution determination – Overview – 2015-20, p. 22

per cent decrease from our last decision for 2015–20. Figure 5 shows the AER's approved regulated revenue in the past two regulatory periods from 2010–11 to 2019–20 ($2019–20, smoothed) compared to the forecast revenue proposed by Energex for the 2020–25 regulatory control period.

Figure 5 Ergon Energy's regulated revenues over time



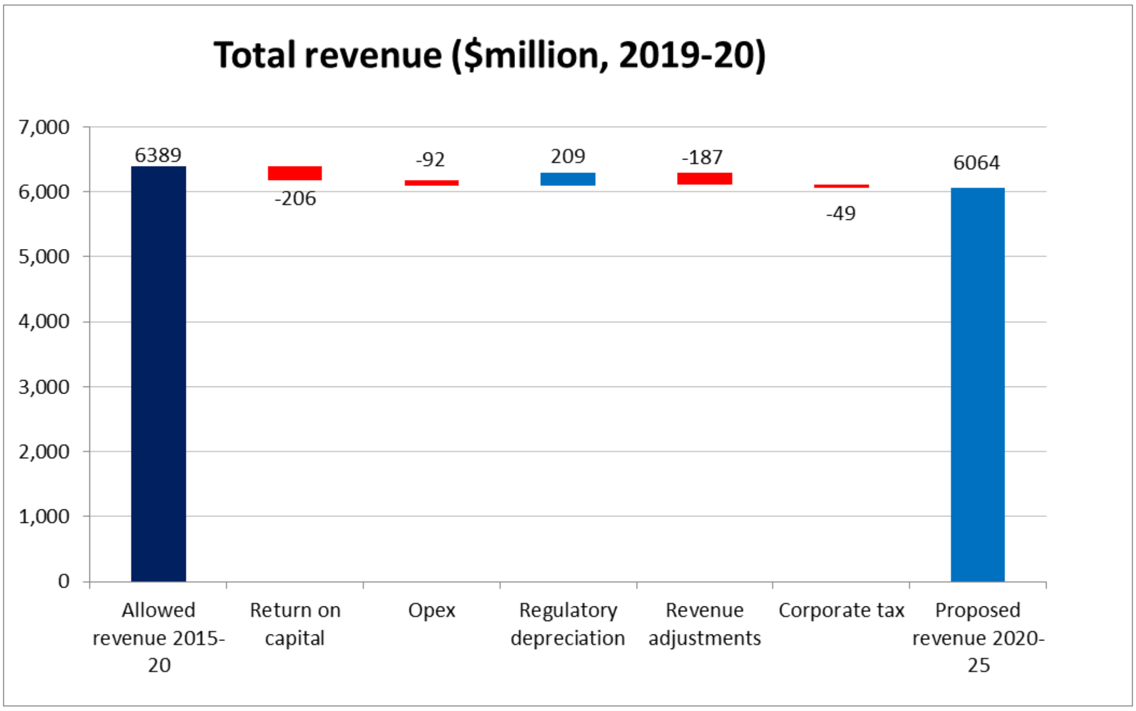
Source: AER analysis based on AER Final decision PTRM for 2010-15 and 2015-20 regulatory periods, as updated post final decision; Ergon Regulatory Proposal PTRM 2020-25 regulatory period, DNSP performance report. Smoothed revenues. Total revenue for 2020-25 is $6061 million (2019-20).

According to Ergon Energy's proposal, the reduction in required revenues are being driven by a number of factors, including:

- one-off operating efficiencies through the merger of Energex and Ergon Energy into Energy Queensland;
- 2.6 per cent annual productivity improvement, resulting in lower forecast opex;
- Lower financing and tax costs;
- subject to approval of the regulatory proposal, foregoing certain incentive payments (CESS and EBSS) from improved efficiencies.

Alongside these savings, we also observe increasing forecast capex which is 8 per cent higher than Ergon Energy's actual net capex for the 2015–20 period, and a RAB around 3 per cent higher in real terms at the end of the 2020–25 period. This is largely being driven by Ergon Energy's replacement capex program which is around 23 per cent higher than the current period. This accelerated replacement program is based on Ergon Energy transitioning to a more proactive replacement approach to assets that are in a poor condition.[10] Figure 6 shows changes in Ergon Energy's proposal at the building block level to illustrate what is driving its proposed revenue. The individual drivers mentioned above are discussed further in section 5.

Figure 6 Changes in building blocks: Ergon Energy's allowed revenue 2015–20 to forecast revenue 2020–25 ($million, 2019/20 – unsmoothed)



Source: AER analysis based on AER Final decision PTRM for 2015-20 regulatory period, as updated post final decision; Ergon Energy Regulatory Proposal PTRM 2020-25 regulatory period.

3.1 How we determine forecast revenue?

The total revenue Energex and Ergon Energy have each proposed reflect their forecasts of the efficient cost of providing its distribution network services over the 2020–25 regulatory control period.

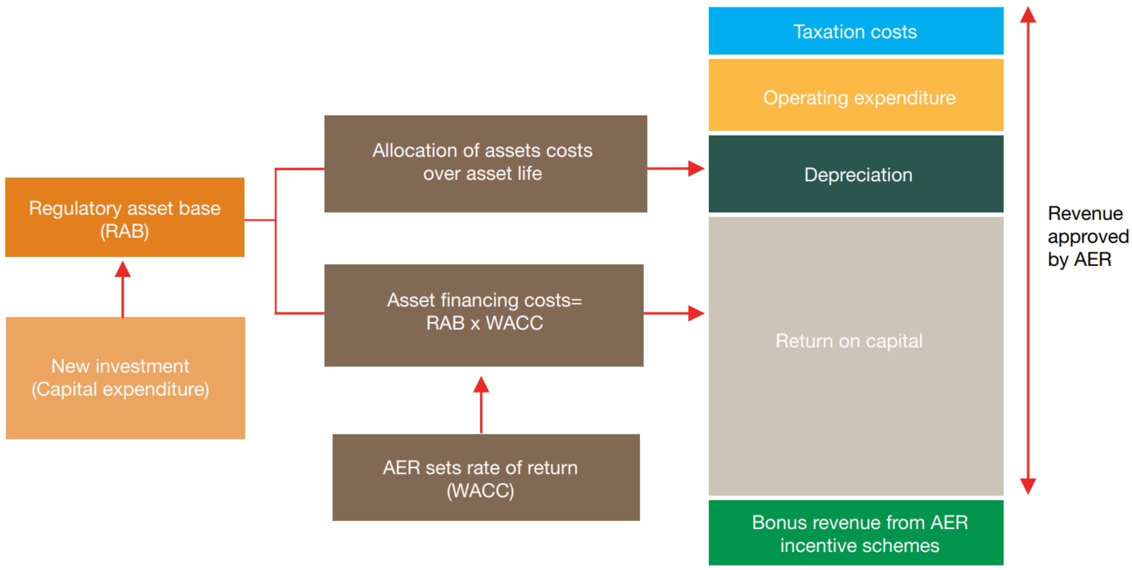
These revenue proposals, and our assessment of them under the National Electricity Law and Rules (NEL and NER), are based on a 'building block' approach (see Figure 7) which looks at five cost components:

- a return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in this business)

[10] Ergon Energy – Regulatory Proposal – January 2019, pp. 58-59

- 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 7 The building block approach for determining total revenue



Source: AER

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 were recently reviewed. The outcomes of these reviews are discussed in sections 3.1.1 and 3.1.2 below.

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.

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

We will apply the 2018 rate of return instrument (the instrument) published by us and the values therein to calculate Ergon and Energex's rate of return.[12] The instrument was developed after extensive consultation and is binding following legislative amendments passed by the South Australian Parliament in December 2018.[13] The instrument also sets out the process by which we will annually update the return on debt (and therefore the overall rate of return) during the regulatory control period.

Ergon and Energex submitted that they have applied the instrument and the key values of its proposal are set out in Figure 8 below.[14]

Figure 8 Key rate of return values

	Energex and Ergon proposal	2018 Instrument
Return on equity	6.26% (indicative)	Risk free rate + 3.66%
Risk free rate	2.6% (indicative)	Based on criteria in the instrument
Market risk premium	6.1%	6.1%
Equity beta	0.6	0.6
Equity risk premium (market risk premium*equity beta)	6.1*0.6%=3.66%	*6.1*0.6%=3.66%
Return on debt (nominal pre–tax)	4.92% (indicative)	Based on criteria in the instrument
Gearing	60%	60%
Gamma (value of imputation credits)	0.585	0.585

Source: AER analysis

3.1.2 Corporate income tax allowance

The building block approach to calculating the annual revenue requirement includes an allowance for the estimated cost of corporate income tax payable by the business. We calculate the expected allowance consistent with the requirements of the NER.[15]

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12 AER, Rate of return instrument, 17 December 2018; AER, Rate of return instrument explanatory statement, December 2018. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-guideline-2018/final-decision

13 Statutes Amendment (National Energy Laws) (Binding Rate of Return Instrument) Act 2018 (SA)

14 Energex, Energex regulatory proposal 2020-25, January 2019, p. 97; Ergon Energy, Regulatory proposal 2020–25, January 2019, p. 94.
We note there appears to be a typo in Ergon Energy's proposal where its proposed market risk premium is 6%, see: Ergon Energy, Regulatory proposal 2020–25, January 2019, p. 95. However, triangulation from its indicative return on equity and attachment 9.002 supports the 6.1% market risk premium from the 2018 Instrument.

15 NER, clause 6.5.3.

Our estimate of the corporate income tax allowance begins with the estimation of the assessable income that would be earned by a benchmark efficient company operating Ergon Energy's and Energex's networks. Estimated tax expenses to be used as tax deductions are then calculated. Estimated tax expenses include interest (using our benchmark 60 per cent gearing), depreciation, operating expenditures, and any capital expenditures that are immediately expensed in accordance with relevant tax law. The taxable income is then determined (assessable income less tax deductions) and the statutory income tax rate of 30 per cent is applied to arrive at the notional tax payable. Finally, an adjustment that reduces the notional tax payable is made to account for the value of imputation credits (gamma), thereby resulting in the net tax allowance that is determined.

In December 2018, we completed a review of our regulatory tax approach.[16] The final report presented analysis of the current tax management practices of the regulated networks and identified some required changes to the estimation of the tax expenses. The changes to our regulatory tax approach require amending our models to:[17]

- recognise immediate tax expensing of some capex forecast for a regulatory control period
- adopt the diminishing value (DV) method for tax depreciation to all future capex except for a limited number of assets which must be depreciated using the straight-line (SL) depreciation method under the tax law.

On 25 January 2019, we released our proposed amendments to the distribution and transmission PTRMs, which implemented these changes for consultation. The final amended PTRMs will be published by the end of April 2019, in time to be applied to the draft decisions for Energex's and Ergon Energy's 2020–25 distribution determinations.

Since the amended PTRM has not been finalised at the time of the submission of Energex's and Ergon Energy's regulatory proposals, the proposals did not account for the changes to the regulatory tax approach from our tax review.[18] To apply these changes we require further information from Energex and Ergon Energy that was not included in their regulatory proposals.

In particular, our draft decision assessment will review information to be provided by Energex and Ergon Energy including:

- Forecast immediately tax expensed capex for each asset class. This input is required to calculate the estimate of tax expenses. Our treatment of forecast immediate expensing of capex will be guided by Energex's and Ergon Energy's actual immediate expensing of capex from the past period and further information to be sought from the businesses.

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16 AER, *Final report: Review of regulatory tax approach*, December 2018, p. 76.

17 Capping of gas asset tax lives was also a finding from the final report, but does not require a model change.

18 Ergon Energy, *Regulatory proposal*, p 99. Energex, *Regulatory proposal*, p. 102.

- Assets which are exempted from the DV tax depreciation method. Our tax review report found that we should apply the DV method as the new regulatory benchmark for calculating tax depreciation to all new capex.[19] However, there are some exceptions to this method under the tax law such as expenditures relating to in-house software, buildings and equity raising costs. We will require Energex and Ergon Energy to re-allocate (where relevant) their forecast capex related to in-house software and buildings from existing asset classes to these new prescribed asset classes if they wish to apply the SL method of tax depreciation to these assets.[20]

We will consult with Energex and Ergon Energy to obtain these inputs and will use them to complete our modelling of the estimated corporate income tax allowance for our draft decisions.

[19] AER, *Final report: Review of regulatory tax approach*, December 2018, p. 76.

[20] The PTRM calculates any equity raising costs requirements using a benchmark approach and applies the SL method of tax depreciation to this amount.

4 Key elements of Energex's revenue proposal

In our decision, we will assess the individual components that make up the building block model driving Energex's proposed revenue. In this section we discuss Energex's proposal regarding the RAB and depreciation and capital expenditure (capex) by its use, namely; augmentation, connections and non-network capex, as well as capitalised overheads. Section 4.3 discusses Energex's operating expenditure (opex) forecasts.

4.1 RAB and depreciation

The RAB is the value of assets used by Energex to provide network services. The value of the RAB substantially impacts the business' 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.

Besides the usual RAB updates for net capex, depreciation and inflation, there is also a legacy issue for the Qld DNSPs' RABs. For the 2020–25 regulatory control period, Energex proposed to include $147 million of information communication technology (ICT) assets in its RAB at 1 July 2020. These assets were previously owned by SPARQ, which was then a part of Energy Queensland, to provide ICT services for Energex in the 2010–15 and 2015–20 regulatory control periods.[21] The cost for providing the services was included as part of Energex's regulated opex allowance for these regulatory control periods.[22] Energex stated that the reason to include these ICT assets into the RAB in the forthcoming period is to improve regulatory transparency.[23]

Figure 9 shows the growth in Energex's RAB. Based on Energex's regulatory proposal, its RAB value is projected to reduce by around 1 per cent in real terms over the 2020–25 regulatory control period.

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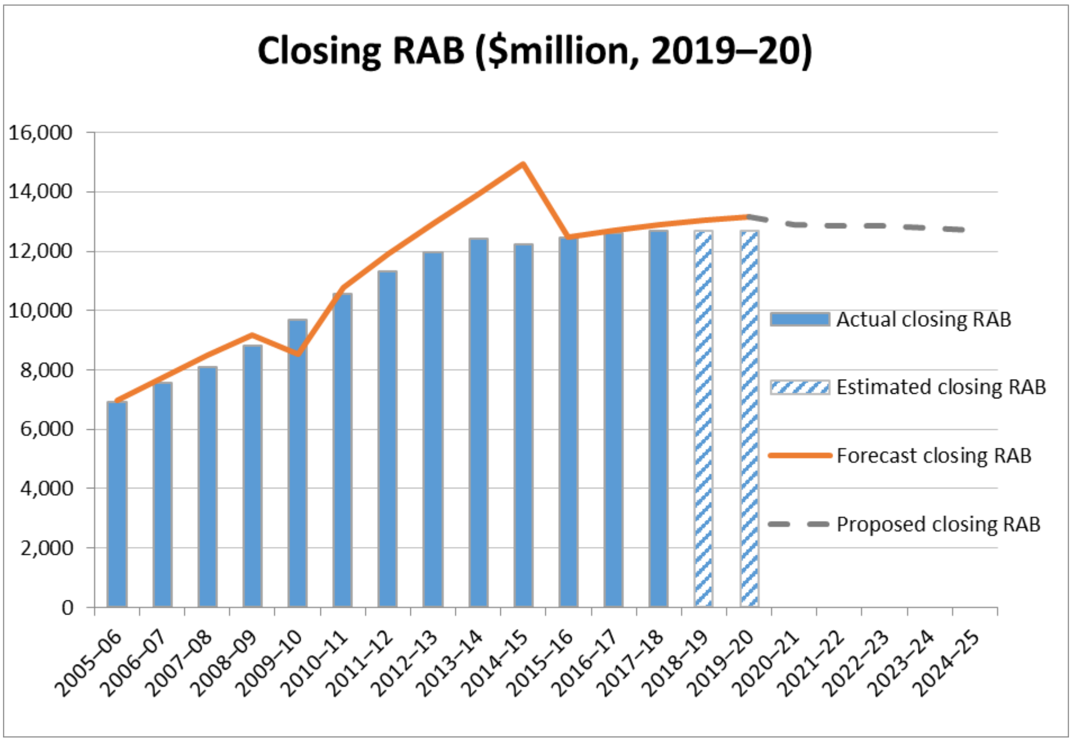
21 Prior to June 2016, SPARQ was a jointly-owned subsidiary of Energex and Ergon Energy. SPARQ's only customers were the two distribution networks (including unregulated entities under the two networks). Following the creation of Energy Queensland on 30 June 2016, SPARQ became a 100% subsidiary of Energy Queensland.

22 Other than the opex component, the remaining parts of the cost were included as the capitalised overheads under the capex allowance.

23 Ergon Energy, *Regulatory proposal*, p 90. Energex, *Regulatory proposal*, p. 92.

Figure 9 Energex's RAB value over time ($million, 2019/20)



Source: AER analysis based on AER Final decision PTRM and RFM for 2010-15 and 2015-20 regulatory periods; Energex Regulatory Proposal PTRM and RFM for 2020-25 regulatory period, DNSP performance report.

Regulatory depreciation is the allowance provided so capital investors can recover their investment over the economic life of the asset (return of capital).The regulatory depreciation allowance is the net total of straight-line depreciation less the inflation indexation adjustment of the RAB.

Energex's proposed regulatory depreciation allowance for 2020–25 is 55 per cent higher in real terms than the allowance we used to set revenues for 2015–20. The increase in proposed depreciation allowance is driven by factors including: an increase in the RAB (which naturally increases depreciation too), introduction of the legacy ICT asset class with a proposed 10 year asset life (which also increases the RAB), and a greater proportion of forecast capex allocated to asset classes with relatively shorter asset lives.

Energex proposed to move to the year-by-year tracking approach for implementing straight-line depreciation from the weighted average remaining lives approach. This proposal adds about 8.1 per cent to the depreciation allowance (or 0.9 per cent to total revenues over the 2020–25 regulatory control period). Year-by-year depreciation tracking improves the matching of depreciation with the assets' underlying economic lives and is currently used by a number of regulated businesses including the SA, Victorian and Tasmanian electricity and gas network service providers. The NER requires the depreciation rate to reflect an asset's economic life. The year-by-year depreciation tracking approach satisfies this requirement. We have limited discretion in this regard.

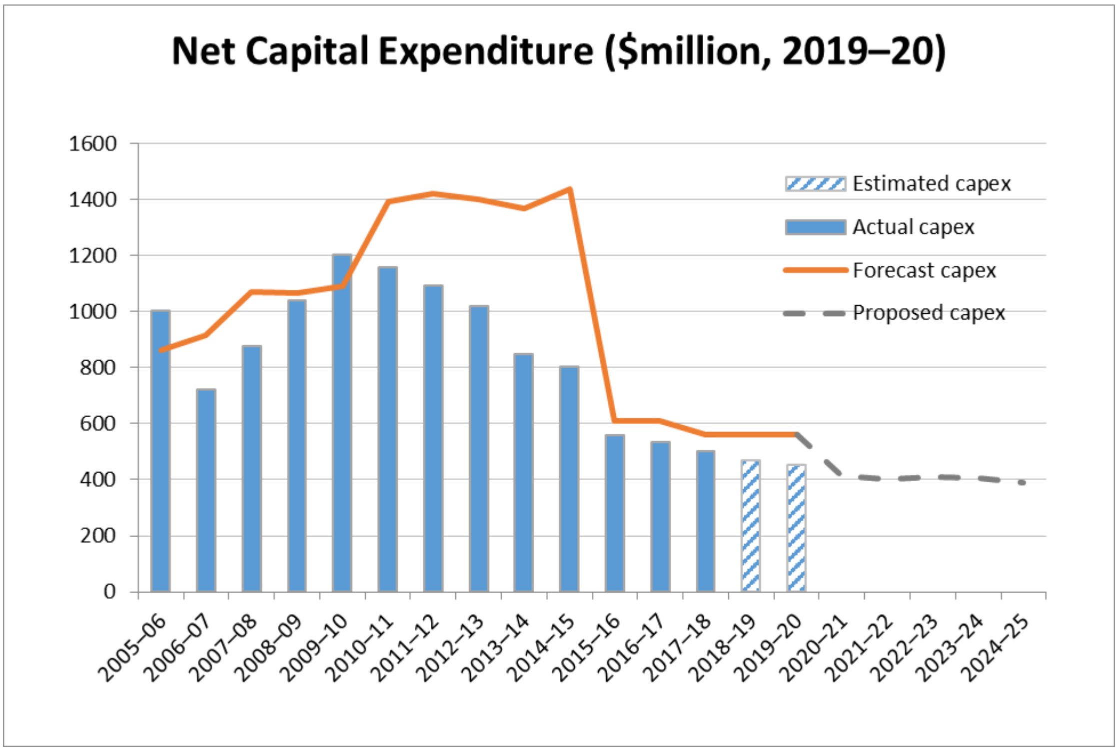
4.2 Capex

Capex is added to Energex'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.

Energex has proposed total forecast net capex of $2.0 billion ($2019–20) for the 2020–25 regulatory control period. This is a decrease of 20 per cent from Energex's actual net capex for the 2015–20 period.[24] Energex has forecast a decrease in all capex categories in 2020–25 compared with the current regulatory period.

Figure 10 shows the trend in Energex's total net capex over time.

Figure 10 Comparison of Energex's past and forecast net capex



Source: AER analysis based on data from AER Final decision PTRM and RFM for 2015-20 regulatory period; Energex Regulatory Proposal PTRM and RFM for the 2020-25 regulatory period.

Note: Total proposed Capital expenditure is $2020 million ($2019-20). These amounts exclude Capcons.

[24] Energex Reset RIN. NB: Energex has adjusted its capex for 2015–20 to put it on a like-for-like basis with its 2020–25 forecast capex. This reflects changes to its cost allocation methodology, classification of service, and reporting). For this reason, AER's capex allowance is not strictly comparable with Energex's historical capex reported in its proposal.

Energex's annual net capex decreased substantially from its peak of around $1.2 billion in 2009–10 to around $453 million in 2019–20. This decrease is forecast to continue, with Energex forecasting annual average capex of around $400 million for the 2020–25 regulatory period.

Energex has proposed net capex of $2.0 billion for the 2020–25 regulatory period, noting that it is "committed to investing capital prudently and efficiently on behalf of customers." Energex submits that its capex focus for 2020–25 is to deliver:[25]

- a no-compromise approach to community and staff safety, leveraging innovative solutions that enable continuous improvement
- sustainable investment to avoid the historical boom-bust cycle and associated future bill shocks, appropriately manage aged assets, and maintain our reliability and security standards while continuing to find cost efficiencies in investments
- investments which support the transition to the future by evolving the network to best enable customer choice in their electricity supply solutions, such that we can integrate solar, batteries and other technologies with the network in a way that is cost effective and sustainable, whilst incorporating non-network alternatives, and
- prudent investment in fit-for-purpose non-network assets to support our staff in efficiently delivering services to [its] customers.

Our role is ensure that Energex's forecast capex for 2020–25 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 Energex'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 safety, sustainability, and prudent investment 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 11 breaks Energex's 2020–25 gross capex forecast into its five main drivers, each of which we discuss briefly below.

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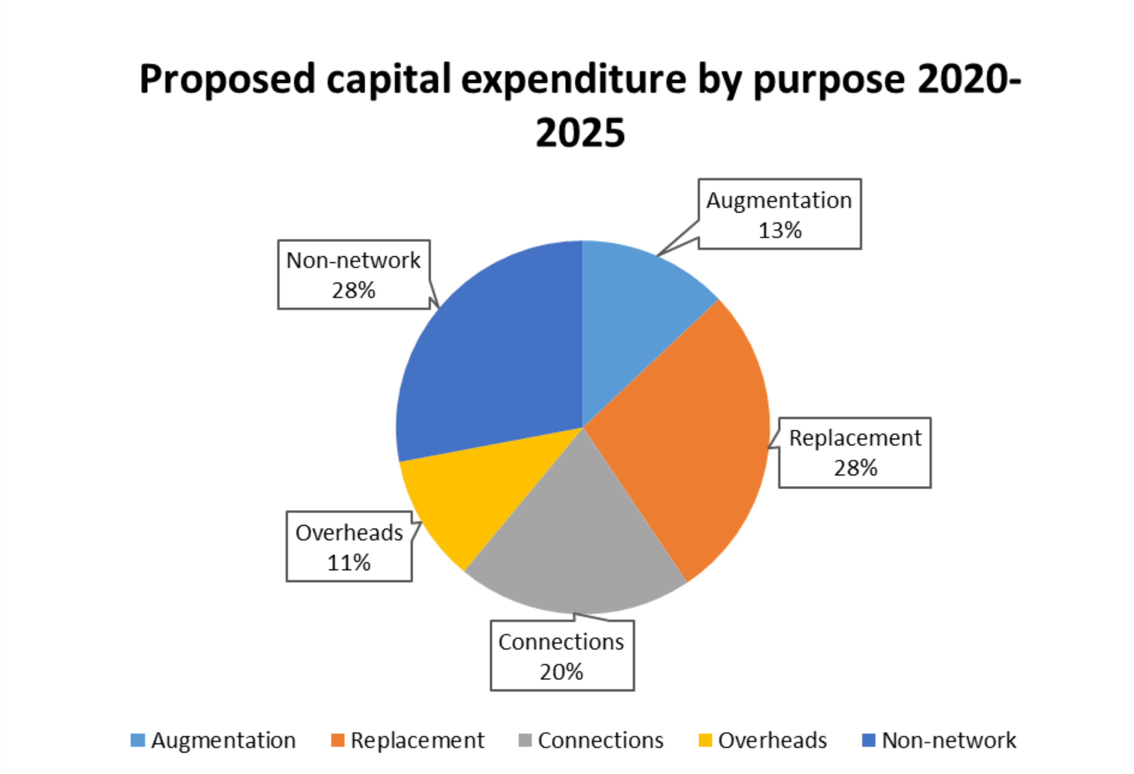
[25] Energex – Regulatory Proposal – January 2019, p. 56.

Figure 11 Energex's forecast gross capex by driver



Source: ENERGEX 2020-25 reset RIN, expenditure summary. ENERGEX 2020-25 Recast CA RIN, expenditure summary.

Note: Total proposed Capital expenditure is $2327 million ($2019-20). These amounts include Capcons of $267m (2019-20).

Replacement capex (repex)

Energex's proposed gross capex includes $643 million, or 28 per cent, related to replacement and renewal of network assets in major projects, planned, conditional and reactive programs. Energex submits that its replacement program is driven largely by assets that are in poor condition and assets that pose a safety risk. This is 26 per cent lower than Energex's replacement capex over the current period.[26]

Energex has broken down its forecast repex for 2020–25 into the following categories:[27]

- Sub-transmission repex – condition and risk $157m
- Distribution repex – condition and risk $341m
- Distribution repex – reactive $85m

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[26] Energex – Regulatory Proposal – January 2019, p. 59.

[27] Energex – Regulatory Proposal – January 2019, p. 66.

- Network control and communication repex $61m.

Energex notes that for the 2020–25 regulatory period it has “focused on the sustainable removal of aged, poor-condition assets to maintain expected network performance for our customers and safety to the community.”[28]

Energex’s largest repex program for 2020–25 is 'Distribution repex – condition and risk'. The major component of this capex is in the distribution line refurbishment programs, which include replacement of overhead conductor, poles and pole top structures that are approaching end of life. Assets that are identified as approaching end of life are prioritised according to overall network risk exposure to maximise prudent investment.[29]

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. Energex tested its repex forecast against the AER’s predictive repex model. It found that its forecast was substantially lower than what the AER’s model predicted.[30]

Augmentation capex (augex)

Energex has proposed $301 million (13 per cent of the capex forecast) for augex, which is 31 per cent lower than for the 2015–20 regulatory period.[31] It notes that augex has steadily decreased since the 2010–15 regulatory period following investment in network security requirements, lower demand growth and cost reductions following the merger. Energex submits that its augex investment is required to service demand growth, support solar PV system uptake, meet statutory obligations and provide functionality to support an intelligent grid.[32]

Energex’s forecast augex program for 2020–25 includes investments relating to growth (57 per cent), network control and communication (22 per cent) and power quality and reliability (22 per cent). Energex notes that the successful use of demand management has been a key driver in decreasing augex in the current and forecast regulatory periods.[33]

Connections capex

28 Energex – Regulatory Proposal – January 2019, p. 65.

29 Energex – Regulatory Proposal – January 2019, pp. 67–68.

30 Energex – Regulatory Proposal – January 2019, p. 69. Energex compared six asset classes that were capable of being modelled (making up 67 per cent of Energex’s total repex proposal).

31 Energex – Regulatory Proposal – January 2019, p. 59.

32 Energex – Regulatory Proposal – January 2019, pp. 70–71.

33 Energex – Regulatory Proposal – January 2019, p. 72.

Energex has proposed $475 million (20 per cent of the capex forecast) in gross connections capex, which is 13 per cent lower than for the 2015–20 regulatory period. This includes:[34]

- $208 million for net connections capex, which is rolled into the RAB and recovered over time through network distribution charges
- $267 million for capital contributions, which is funded by connecting customers through cash contributions and gifted assets.

Compared with the current regulatory period, forecast net connections capex is 3 per cent lower, and forecast capital contributions is 19 per cent lower.

Energex note that there was a high amount of connection works earlier this decade due to a boom in apartment developments and manufacturing sites. Energex expects a steadying in economic activity—and consequently a decrease in connection activity—for the 2020–25 regulatory period.[35]

Non network capex

Non-network capex includes expenditure on information and communications technology (ICT), buildings and property, motor vehicles, and tools and equipment.

Energex's non-network capex forecast for 2020–25 is $651 million. This includes $294 million for information and communications technology (ICT capex), $182 million for fleet and equipment and $174 million for property.[36]

ICT

Energex's ICT services vendor, SPARQ Solutions Pty Ltd, became a fully-owned subsidiary of Energy Queensland in 2016. As a result, from 1 July 2020 Energy Queensland proposes to allocate relevant assets, previously owned by SPARQ, to Energex's RAB.[37]

Energex's ICT capex forecast for 2020–25 is $294 million, which is a small decrease from its expenditure in the current regulatory period ($307 million).[38]

Energex states that legacy applications will be consolidated with Ergon as they are renewed. It points to this transformation program as a key driver for reductions in forecast indirect costs and labour costs for Energy Queensland.[39] It submits that its "proposed ICT investment is essential to support the transformation of our business and supports the delivery of our forecast opex and capex savings…this lower cost

34 Energex – Regulatory Proposal – January 2019, pp. 59, 75.

35 Energex – Regulatory Proposal – January 2019, p. 74.

36 Energex – Regulatory Proposal – January 2019, pp. 59.

37 Energex – Regulatory Proposal – January 2019, pp. 75–76.

38 Energex – Regulatory Proposal – January 2019, p. 77.

39 Energex Energy – Regulatory Proposal – January 2019, p. 77.

base flows through to lower revenue requirements and has enabled us to propose our real reductions in distribution network charges for our customers."[40]

Fleet and equipment

Energex's fleet and equipment forecast for 2020–25 is $182 million, which is 8 per cent lower than the current period. It submits that a large proportion of its elevated work platform and mobile generator fleets are due for replacement within the 2020–25 regulatory period. This is offset by an increase in the replacement cycle for its light vehicle fleet and life extension of suitable plant through refurbishment.[41]

Property

Energex's property forecast for 2020–25 is $174 million, which is 11 per cent lower than the current period. It submits that it will "bring forward initiatives that will drive business benefits and lower costs in the long term."[42]

Capitalised overheads

Energex's capitalised overheads forecast for 2020–25 is $257 million, which is 19 per cent lower than the current period.[43] This is the same as the decrease in forecast direct net capex.[44]

Energex used a base-step-trend approach to forecast capitalised overheads. This involved:

- using 2018–19 as the base year
- making adjustments to remove non-recurrent expenditure and to reflect productivity targets
- applying growth factors for output and labour and non-labour prices
- Energex not proposing a step-change.[45]

4.3 Opex

Operating expenditure (opex) refers to the operating, maintenance and other noncapital expenses incurred in the provision of network services. Forecast opex is one of the building blocks we use to determine Energex's total regulated revenue requirement.

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40 Energex – Regulatory Proposal – January 2019, p. 78.
41 Energex – Regulatory Proposal – January 2019, p. 79.
42 Energex – Regulatory Proposal – January 2019, p. 80.
43 Energex – Regulatory Proposal – January 2019, p. 82.
44 That is, forecast net capex less forecast capitalised overheads.
45 Energex – Regulatory Proposal – January 2019, pp. 81–82.

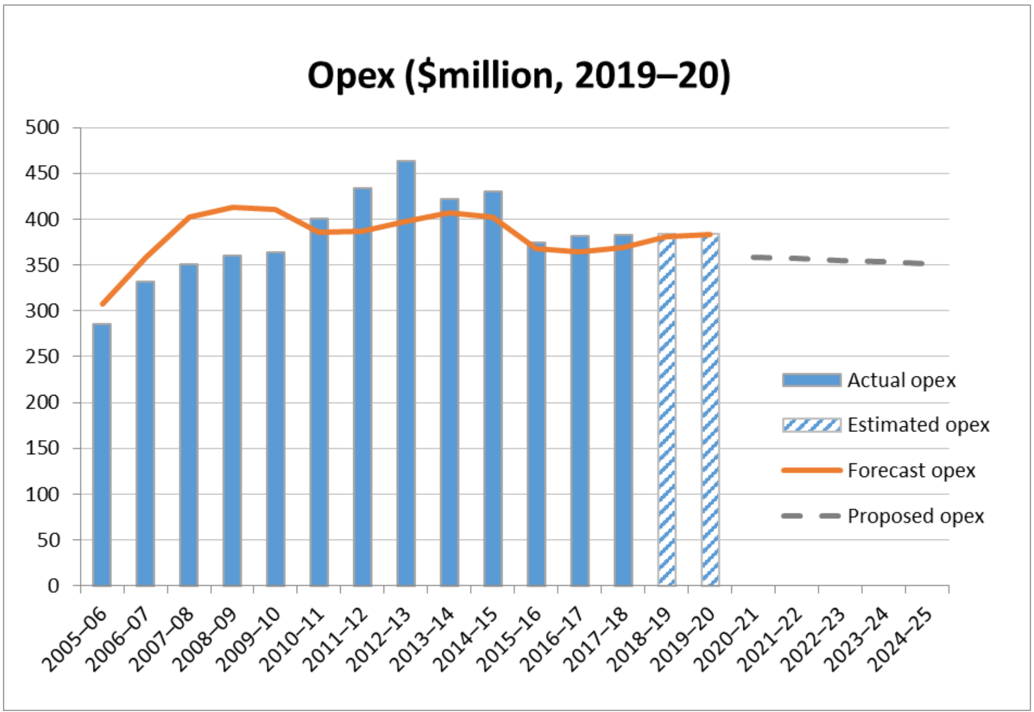
Energex's revenue proposal for the 2020-25 regulatory control period includes total forecast opex of $1805.8 million ($2019-20).[46] This is:

- a decrease of $105.5 million (or 5.5 per cent) compared to its estimated opex over the 2015-20 regulatory period
- $99.7 million (or 5.2 per cent) less than the opex forecast included in our final decision for the 2015-20 regulatory period.

Energex proposes to achieve a downward trend in opex in each year of the next regulatory period through a combination of downward adjustments to its 2018-19 base year opex and a negative rate of change.

Figure 12 provides a comparison between Energex's historical opex, its estimated opex in 2018-19 and 2019-20, and its forecast opex for the 2020-25 regulatory period.

Figure 12 Comparison of Energex's past and forecast opex



Source: AER analysis.

Note: Excludes solar bonus opex. Opex includes debt-raising costs. Actual and forecast debt-raising costs up to and including 2019-20 are zero.

Energex has used a base-step-trend methodology to forecast its opex requirements for the 2020-25 regulatory control period. This is consistent with our preferred approach to assessing opex, as outlined in our Expenditure Forecast Assessment Guideline.[47]

[46] Includes debt-raising costs. Energex 6.007 opex forecast - SCS Jan19 Public.

Energex proposes using 2018-19 as its base year to forecast total opex for the 2020-25 regulatory control period. Energex states that the level of opex incurred in this year represents a realistic expectation of the efficient and sustainable level of opex that will be required in the 2020-25 regulatory control period. Energex notes that 2018-19 also represents:

- the most recent year for which audited data is available
- the first year to largely reflect the level of opex under the merger of Energex and Ergon into Energy Queensland.[48]

Energex estimates 2018-19 base year opex of $376.6 million ($2019-20).[49] This contributes $1872.3 million ($2019-20) to its total opex proposal. Energex then adjusts this amount with:

- an increase in opex for service classification changes ($12.8 million, $2019-20)
- an increase in opex for cost allocation method (CAM) changes ($36.0 million, $2019-20)
- a decrease in opex to remove non-recurring costs (i.e. 'change costs' such as redundancies that Energex has incurred to reform its business) and post-merger savings expected in 2019-20 ($123.6 million, $2019-20)[50]
- an increase in opex in the final year of the current regulatory control period ($10.6 million, $2019-20).

Energex's proposal then accounts for changes in trend factors (i.e. output, input price and productivity growth) to produce an overall decreasing trend in opex in each year of the 2020-25 regulatory period. These adjustments include:

- an increase in opex to account for expected output growth ($54.4 million, $2019-20). Energex uses the weights and methodology generally applied by the AER.
- an increase in opex to account for changes in real input prices ($3.5 million, $2019-20). Energex uses the weights generally applied by the AER. Its forecast input price growth rate is moderated by Energex's inclusion of a 'management productivity' adjustment, which decreases input price growth by an average annual amount of 0.59 percent.
- a decrease in opex to account for forecast average annual productivity growth of 1.7 per cent ($91.2 million, $2019-20). Energex's productivity

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47 AER website: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/expenditure-forecast-assessment-guideline-2013

48 Energex – Regulatory Proposal – January 2019, p.47.

49 Energex – Regulatory Proposal – January 2019, p.48. The estimate will be updated in Energex's revised regulatory proposal.

50 Energex – Regulatory Proposal – January 2019, pages 47-48.

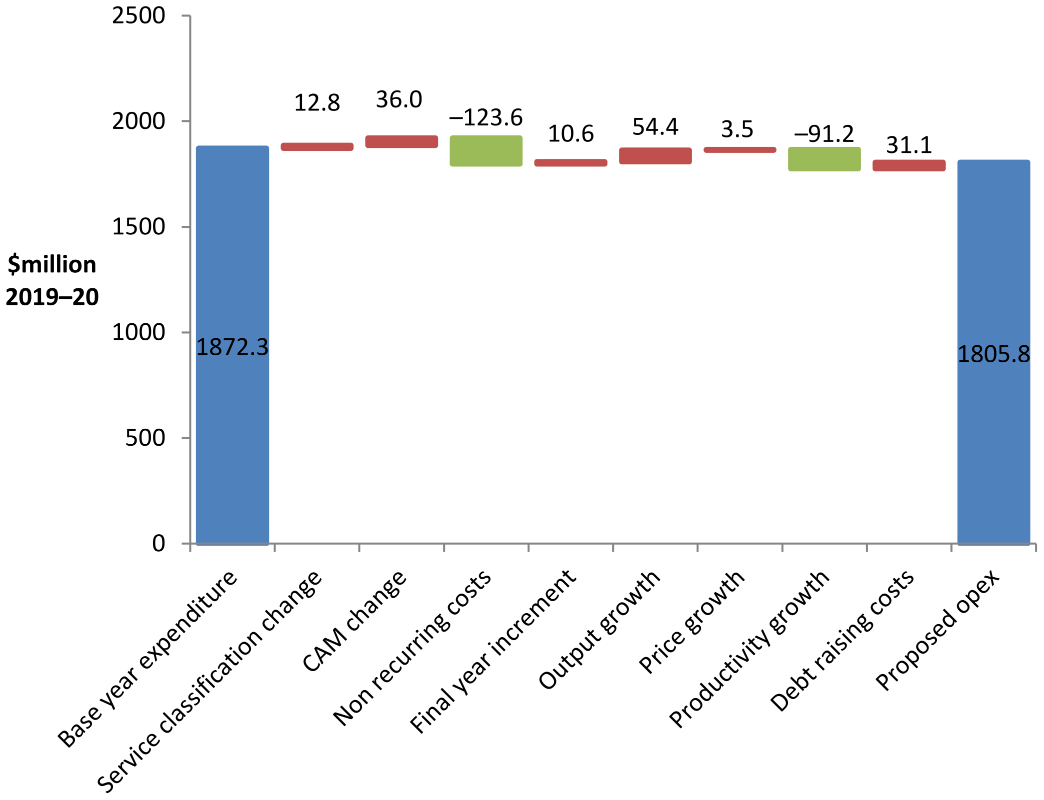
growth forecast is above our revised approach to forecasting productivity growth.[51]

Energex has not proposed any step changes.

Energex has also included $31.1 million ($2019-20) of debt raising cost in its opex forecast.[52] 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 13 shows how each of these components has contributed to Energex's total opex forecast.

Figure 13 Breakdown of Energex's opex forecast ($million, $2019-20)



Source: AER analysis.

We are interested in understanding stakeholder views as to how well Energex's forecast opex —summarised above—reasonably reflects the efficient costs of a

[51] The final decision of the AER's review of forecasting opex productivity growth for electricity distributors, published 8 March 2019, sets our productivity forecast at 0.5 per cent (average annual).

[52] Energex 6.007 Opex forecast - SCS Jan19 Public.

prudent operator. We are also interested in gauging the extent to which electricity consumers consider Energex's opex forecast has addressed the concerns identified over the course of its consumer engagement program.

5 Key elements of Ergon Energy's revenue proposal

In this section we further break down some of the drivers of Ergon Energy’s proposed revenue, namely the Regulatory Asset Base (RAB) and depreciation, the components of capex, as well as the Opex forecast.

5.1 RAB and depreciation

The RAB is the value of assets used by Ergon Energy to provide network services. The value of the RAB substantially impacts the business’ 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.

Besides the usual RAB updates for net capex, depreciation and inflation, there is also a legacy issue for the Qld DNSPs’ RABs. For the 2020–25 regulatory control period, Ergon Energy proposed to include $154 million of information communication technology (ICT) assets in its RAB at 1 July 2020. These assets were previously owned by SPARQ, which was then a part of Energy Queensland, to provide ICT services for Ergon Energy in the 2010–15 and 2015–20 regulatory control periods.[53] The cost for providing the services was included as part of Ergon Energy's regulated opex allowance for these regulatory control periods.[54] Ergon Energy stated that the reason to include these ICT assets into the RAB in the forthcoming period is to improve regulatory transparency.[55]

Figure 14 shows the growth in Ergon Energy's RAB. Based on Ergon Energy's regulatory proposal, its RAB value is projected to increase by around 3 per cent in real terms over the 2020–25 regulatory control period.

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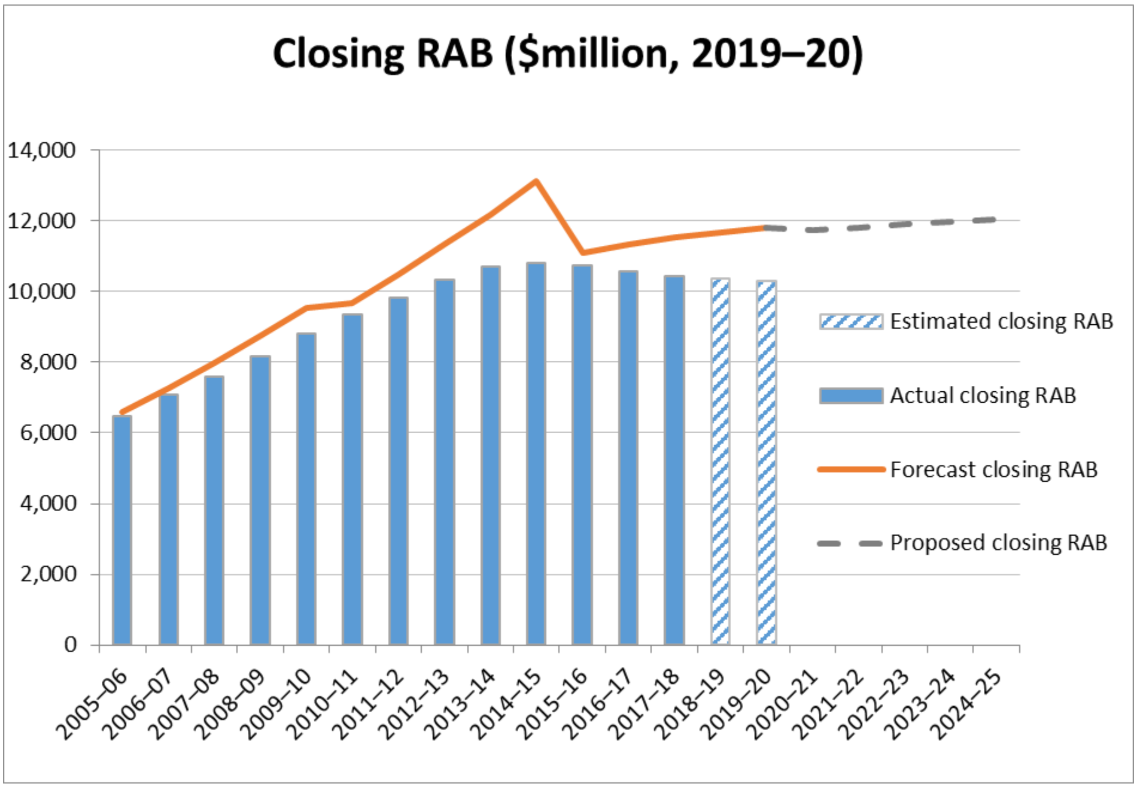
[53] Prior to June 2016, SPARQ was a jointly-owned subsidiary of Energex and Ergon Energy. SPARQ’s only customers were the two distribution networks (including unregulated entities under the two networks). Following the creation of Energy Queensland on 30 June 2016, SPARQ became a 100% subsidiary of Energy Queensland.

[54] Other than the opex component, the remaining parts of the cost were included as the capitalised overheads under the capex allowance.

[55] Ergon Energy, *Regulatory proposal*, p 90.

Figure 14 Ergon Energy's RAB ($million, 2019/20)



Source: AER analysis based on AER Final decision PTRM and RFM for 2010-15 and 2015-20 regulatory periods; Ergon Energy Regulatory Proposal PTRM and RFM for 2020-25 regulatory period, DNSP performance report.

Regulatory depreciation is the allowance provided so capital investors can recover their investment over the economic life of the asset (return of capital).The regulatory depreciation allowance is the net total of straight-line depreciation less the inflation indexation adjustment of the RAB.

Ergon Energy's proposed regulatory depreciation allowance for 2020–25 is 27 per cent higher in real terms than the allowance we used to set revenues for 2015–20. The increase in proposed depreciation allowance is driven by various factors including: the increase in the RAB (which naturally increases depreciation too), introduction of the legacy ICT asset class with a proposed 10 year asset life (which also increases the RAB), and a greater proportion of forecast capex allocated to asset classes with relatively shorter asset lives.

Ergon Energy proposed to move to the year-by-year tracking approach for implementing straight-line depreciation from the period-by-period depreciation approach. This proposal has a negligible impact on the depreciation allowance. Year-by-year depreciation tracking improves the matching of depreciation with the assets' underlying economic lives and is currently used by a numbers of regulated businesses including the SA, Victorian and Tasmanian electricity and gas network service providers. The NER requires the depreciation rate to reflect an asset's economic life.

The year-by-year depreciation tracking approach satisfies this requirement. We have limited discretion in this regard.

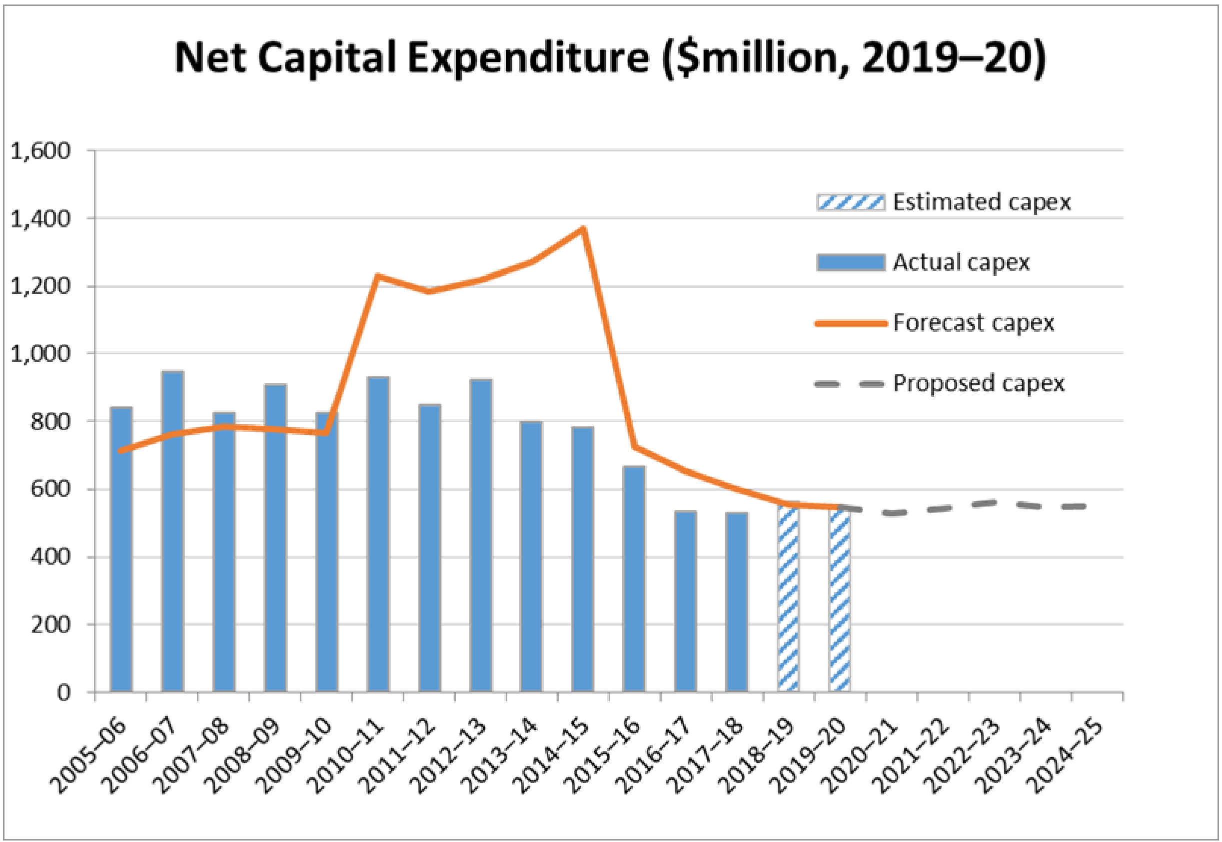
5.2 Capex

Capex is added to Ergon Energy'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.

Ergon has proposed total forecast net capex of $2.7 billion ($2019–20) for the 2020–25 regulatory control period. This is an increase of 8 per cent from Ergon's actual net capex for the 2015–20 period.[56]

Figure 15 shows the trend in Ergon Energy's total net capex over time.

Figure 15 Comparison of Ergon Energy's past and forecast net capex



Source: AER analysis based on data from AER Final decision PTRM and RFM for 2015-20 regulatory period; Ergon Regulatory Proposal PTRM and RFM for the 2020-25 regulatory period.

[56] Ergon Energy Reset RIN. NB: Ergon Energy has adjusted its capex for 2015–20 to put it on a like-for-like basis with its 2020–25 forecast capex. This reflects changes to its cost allocation methodology, classification of service, and reporting). For this reason, AER's capex allowance is not strictly comparable with Ergon's historical capex reported in its proposal.

Ergon Energy’s net capex was relatively consistent between 2005–06 and 2014–15 in real terms, despite an increase in the AER’s capex allowance for the 2010–15 regulatory period. It spent around $4.3 billion in capex for both the 2005–10 and 2010–15 regulatory periods. Ergon Energy’s net capex in 2015–20 is $2.5 billion, representing a decrease of more than 40 per cent compared with the previous regulatory period.

Ergon Energy has proposed net capex of $2.7 billion for the 2020–25 regulatory period, noting that it is “committed to investing capital prudently and efficiently on behalf of customers.” Ergon Energy submits that its capex focus for 2020–25 is to deliver:[57]

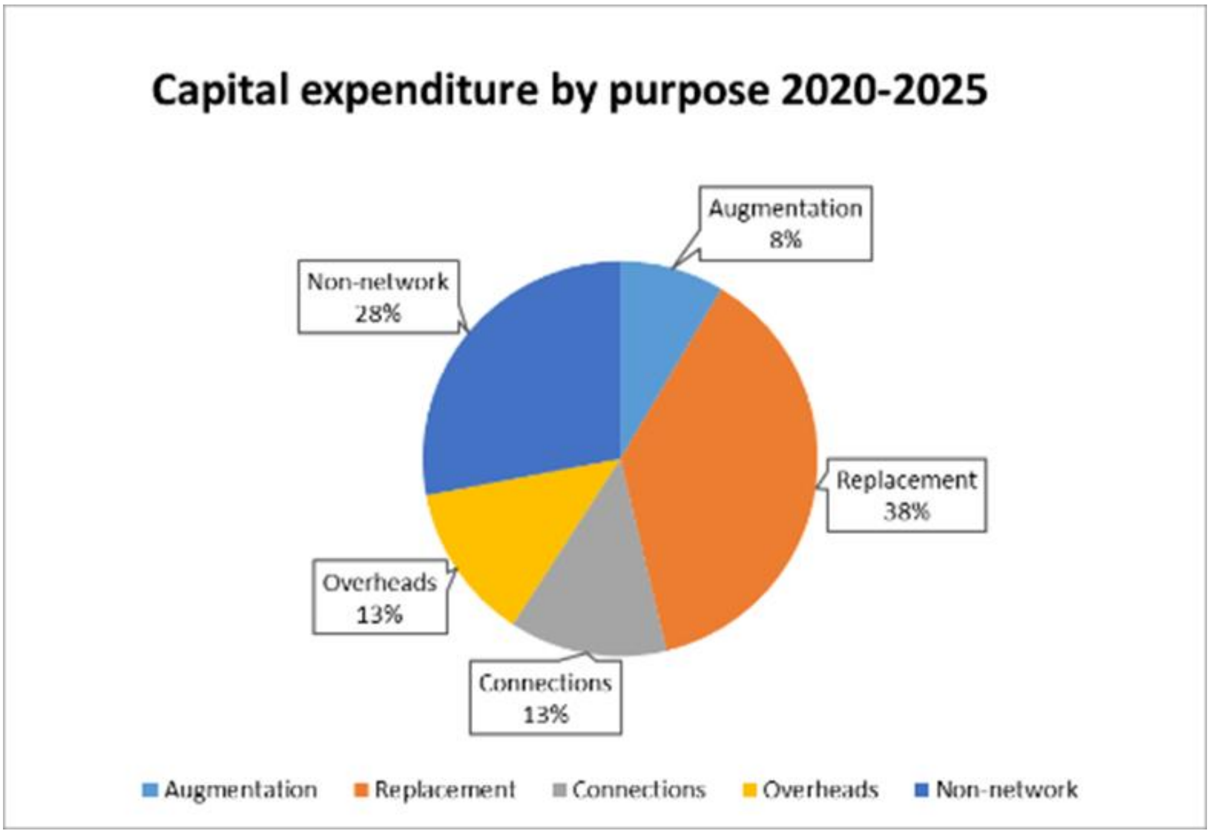
- a no-compromise approach to community and staff safety, leveraging innovative solutions that enable continuous improvement
- sustainable investment to avoid the historical boom-bust cycle and associated future bill shocks, appropriately manage aged assets, and maintain our reliability and security standards while continuing to find cost efficiencies in investments
- investments which support the transition to the future by evolving the network to best enable customer choice in their electricity supply solutions, such that we can integrate solar, batteries and other technologies with the network in a way that is cost effective and sustainable, whilst incorporating non-network alternatives, and
- prudent investment in fit-for-purpose non-network assets to support our staff in efficiently delivering services to our customers.

Our role is ensure that Ergon Energy's forecast capex for 2020–25 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 Ergon Energy'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 safety, sustainability and prudent investment 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 16 breaks Ergon Energy's 2020–25 gross capex forecast into its four main drivers, each of which we discuss briefly below.

[57] Ergon Energy – Regulatory Proposal – January 2019, p. 54.

Figure 16 Ergon Energy's forecast gross capex by driver



Source: Ergon Reset RIN, AER analysis.

Replacement capex (repex)

$1094 million, or 38 per cent, of Ergon Energy's proposed gross capex relates to replacement and renewal of network assets in major projects, planned, conditional and reactive programs. Ergon Energy's replacement program is driven largely by assets that are in poor condition and assets that pose a safety risk. This is 23 per cent higher than Ergon Energy's replacement capex over the current period.[58]

Ergon Energy has broken down its forecast repex for 2020–25 into the following categories:[59]

- Sub-transmission repex – condition and risk $243m
- Distribution repex – condition and risk $297m
- Distribution repex – reactive $514m
- Network control and communication repex $41m.

[58] Ergon Energy – Regulatory Proposal – January 2019, p. 57.

[59] Ergon Energy – Regulatory Proposal – January 2019, p. 64.

Ergon Energy notes that the forecast increase in repex compared with the current period is driven by maintaining or improving safety where relevant; an increase in replacement relative to repairs and maintenance; reducing network risk of the overhead distribution network (poles and wires); and transitioning to a more proactive replacement approach for sustainable asset management.[60] Ergon Energy states that, despite taking a more proactive approach to replacing assets, risk has continued to grow across the network over the current regulatory period due to the age profile of its assets.[61] Consistent with our standard approach to replacing assets, our review will focus on Ergon Energy's overall risk assessment and areas where it has identified safety risk concerns. We will appraise how Ergon Energy has quantified risk when coming to our view on whether its repex forecast forms part of a capex proposal that is likely to be prudent and efficient.

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. Ergon Energy tested its repex forecast against the AER's predictive repex model. It found that its forecast was higher than what the AER's model predicted; however, it noted that both its forecast and the model predicted a similar underlying trend in required repex over the next regulatory period.[62]

Augmentation capex (augex)

Ergon Energy has proposed $249 million (8 per cent of the capex forecast) for augex, which is 10 per cent lower than for the 2015–20 regulatory period.[63] It submits that this investment is required to service demand growth, support solar PV system uptake, meet statutory obligations and provide functionality to support an intelligent grid.[64]

Ergon Energy's forecast augex program for 2020–25 includes investments relating to growth (65 per cent), network control and communication (28 per cent) and power quality and reliability (8 per cent). Ergon Energy notes that the successful use of demand management has been a key driver in decreasing augex in the current and forecast regulatory periods.[65]

Connections capex

60 Ergon Energy – Regulatory Proposal – January 2019, pp. 58-59.

61 Ergon Energy – Regulatory Proposal – January 2019, p. 63.

62 Ergon Energy – Regulatory Proposal – January 2019, p. 68. Ergon compared six asset classes that were capable of being modelled (making up 67 per cent of Ergon's total repex proposal).

63 Ergon Energy – Regulatory Proposal – January 2019, p. 69

64 Ergon Energy – Regulatory Proposal – January 2019, pp. 68–69.

65 Ergon Energy – Regulatory Proposal – January 2019, p. 70.

Ergon Energy has proposed $376 million (13 per cent of the capex forecast) in gross connections, which is 14 per cent lower than for the 2015–20 regulatory period. This includes:[66]

- $206 million for net connections capex, which is rolled into the RAB and recovered over time through network distribution charges
- $170 million for capital contributions, which is funded by connecting customers through cash contributions and gifted assets.

Compared with the current regulatory period, forecast net connections capex is 8 per cent lower, and forecast capital contributions is 19 per cent lower.

Ergon Energy states that connections capex has declined in recent years, reflecting prevailing economic conditions. It expects this decline to continue, and has therefore forecast lower connections capex in 2020–25 compared with the current regulatory period.

Non network capex

Non-network capex includes expenditure on information and communications technology (ICT), buildings and property, motor vehicles, and tools and equipment.

Ergon Energy's non-network capex forecast for 2020–25 is $812 million. This includes $367 million for information and communications technology (ICT capex), $225 million for fleet and equipment and $220 million for property.[67]

ICT

Ergon Energy’s ICT services vendor, SPARQ Solutions Pty Ltd, became a fully-owned subsidiary of Energy Queensland in 2016. As a result, from 1 July 2020 Energy Queensland proposes to allocate relevant assets, previously owned by SPARQ, to Ergon Energy’s RAB.[68]

Ergon Energy's ICT capex forecast for 2020–25 is $367 million, which is about the same as its expenditure in the current regulatory period ($364 million).[69]

Ergon Energy states that legacy applications will be consolidated with Energex as they are renewed. It points to this transformation program as a key driver for reductions in forecast indirect costs and labour costs for Energy Queensland.[70] It submits that “our proposed ICT investment is essential to support the transformation of our business and supports the delivery of our forecast opex and capex savings…this lower cost base

[66] Ergon Energy – Regulatory Proposal – January 2019, pp. 72–73.
[67] Ergon Energy – Regulatory Proposal – January 2019, p. 57.
[68] Ergon Energy – Regulatory Proposal – January 2019, p. 74.
[69] Ergon Energy – Regulatory Proposal – January 2019, p. 75.
[70] Ergon Energy – Regulatory Proposal – January 2019, p. 76.

flows through to lower revenue requirements and has enabled us to propose our real reductions in distribution network charges for our customers."[71]

Fleet and equipment

Ergon Energy's fleet and equipment forecast for 2020–25 is $225 million, which is 12 per cent higher than the current period. It submits that a large proportion of its elevated work platform and mobile generator fleets are due for replacement within the 2020–25 regulatory period. This is offset by an increase in the replacement cycle for its light vehicle fleet and life extension of suitable plant through refurbishment.[72]

Property

Ergon Energy's property forecast for 2020–25 is $220 million, which is 5 per cent higher than the current period. It submits that it is "bringing forward initiatives that will drive business benefits and lower costs in the long term."[73]

Capitalised overheads

Ergon Energy's capitalised overheads forecast for 2020–25 is $374 million, which is 4 per cent higher than the current period.[74] This compares with a 9 per cent increase in forecast direct net capex.[75]

Ergon Energy used a base-step-trend approach to forecast capitalised overheads. This involved:

- using 2018–19 as the base year
- making adjustments to remove non-recurrent expenditure and to reflect productivity targets
- applying growth factors for output and labour and non-labour prices
- Ergon Energy has not proposed a step-change.[76]

5.3 Opex

Operating expenditure (opex) refers to the operating, maintenance and other noncapital expenses incurred in the provision of network services. Forecast opex is one of the building blocks we use to determine Ergon Energy's total regulated revenue requirement.

71 Ergon Energy – Regulatory Proposal – January 2019, p. 77.
72 Ergon Energy – Regulatory Proposal – January 2019, p. 77.
73 Ergon Energy – Regulatory Proposal – January 2019, p. 78.
74 Ergon Energy – Regulatory Proposal – January 2019, p. 80.
75 That is, forecast net capex less forecast capitalised overheads.
76 Ergon Energy – Regulatory Proposal – January 2019, p. 79.

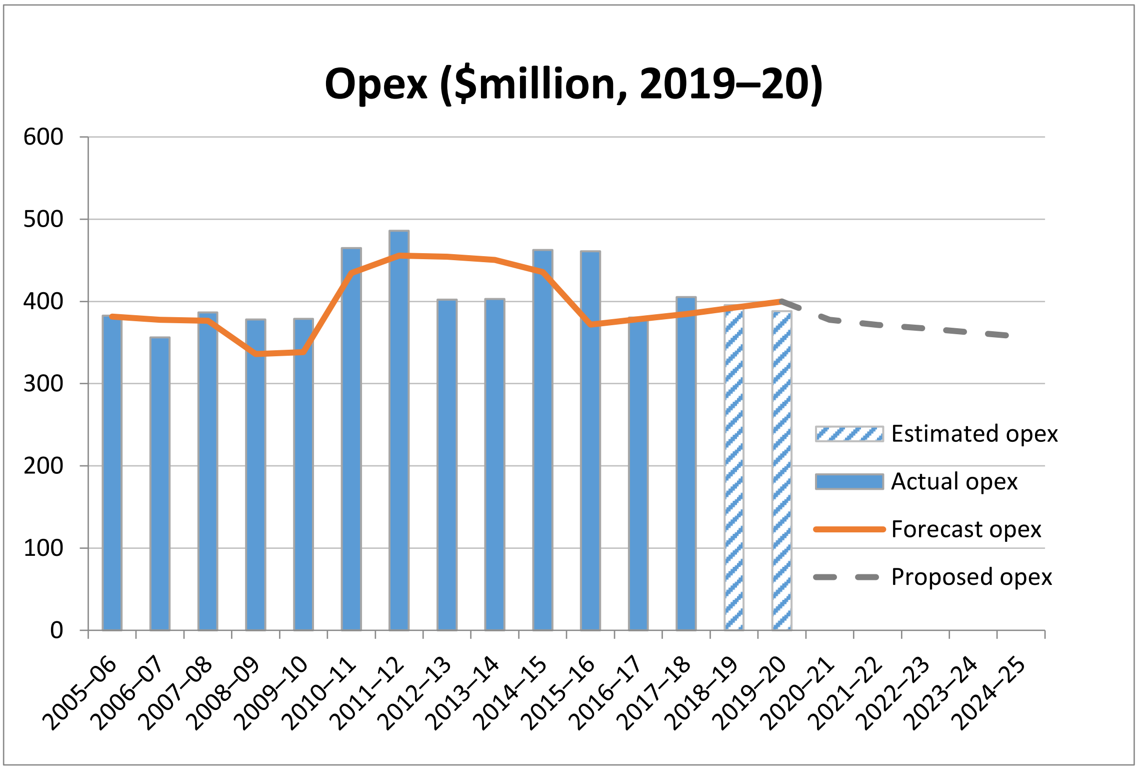
Ergon Energy's revenue proposal for the 2020-25 regulatory control period includes total forecast opex of $1834.6 million ($2019/20).[77] This is:

- a decrease of $195.9 million (9.6 per cent) compared to its estimated opex over the 2015-20 regulatory period[78]
- $92.5 million (or 4.8 per cent) less than the opex forecast included in our final decision for the 2015-20 regulatory period.

Ergon Energy proposes to achieve a downward trend in opex in each year of the next regulatory period through a combination of downward adjustments to its 2018-19 base year opex and a negative rate of change.

Figure 17 provides a comparison between Ergon Energy's historical opex, its estimated opex in 2018-19 and 2019-20, and its forecast opex for the 2020-25 regulatory control period.

Figure 17 Comparison of Ergon Energy's past and forecast opex



Source: AER analysis.

Note: Excludes solar bonus opex. Opex includes debt-raising costs. Actual and forecast debt-raising costs up to and including 2019-20 are zero. Actual opex has been updated to reflect material impacts of more closely

[77] Includes debt-raising costs. Ergon 6.008 opex forecast - SCS Jan19 Public.

[78] Ergon's estimate of total opex for the 2015-20 regulatory control period has been updated to reflect material impacts of more closely aligning Ergon's cost allocation methods and service classifications with those of Energex's following their merger under Energy Queensland.

aligning Ergon's cost allocation methods and service classifications with those of Energex's following their merger under Energy Queensland.

Ergon Energy has used a base-step-trend methodology to forecast its opex requirements for the 2020-25 regulatory control period. This is consistent with our preferred approach to assessing opex, as outlined in our Expenditure Forecast Assessment Guideline.[79]

Ergon Energy proposes using 2018-19 as its base year to forecast total opex for the 2020-25 regulatory control period. Ergon Energy states that the level of opex incurred in this year represents a realistic expectation of the efficient and sustainable level of opex that will be required in the 2020-25 regulatory control period. Ergon Energy notes that 2018-19 also represents:

- the most recent year for which audited data is currently available
- the first year to largely reflect the level of opex under the merger of Energex and Ergon into Energy Queensland.[80]

Ergon Energy estimates 2018-19 base year opex of $387.1 million ($2019-20).[81] This contributes $1898.9 million ($2019-20) to its total opex proposal. Ergon Energy then adjusts this amount with:

- an increase in opex for service classification changes ($0.4 million, $2019-20)
- an increase in opex for cost allocation method (CAM) changes ($78.7 million, $2019-20)
- a decrease in opex to remove non-recurring costs ($127.0 million, $2019-20) (i.e. 'change costs' such as redundancies that Ergon Energy has incurred to reform its business) and post-merger savings expected in 2019-20[82]
- an increase in opex for the final year increment of the current regulatory control period ($36.6 million, $2019-20).

Ergon Energy's proposal then accounts for changes in trend factors (i.e. output, input price and productivity growth) to produce a decreasing trend in opex in each year of the next regulatory period. These adjustments include:

- an increase in opex to account for expected output growth ($56.5 million, $2019-20). Ergon Energy uses the weights and methodology generally applied by the AER.

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79 AER website: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/expenditure-forecast-assessment-guideline-2013

80 Ergon Energy – Regulatory Proposal – January 2019, p.46. From 30 June 2016 Energex and Ergon Energy merged under the banner of Energy Queensland Limited.

81 Ergon Energy – Regulatory Proposal – January 2019, p. 47. This estimate will be updated in Ergon's revised regulatory proposal.

82 Ergon Energy – Regulatory Proposal – January 2019, pages 46-47.

- an increase in opex to account for changes in real input prices ($3.5 million, $2019-20). Ergon Energy uses the weights generally applied by the AER. Ergon Energy's forecast input price growth rate is moderated by its inclusion of a 'management productivity' adjustment, which decreases the input price growth by an average annual amount of 0.59 percent.
- a decrease in opex to account for forecast positive average annual productivity growth of 2.6 per cent ($141.4 million, $20-19-20). Ergon Energy's productivity growth forecast is above our revised approach to forecasting productivity growth.[83]

Ergon Energy has not proposed any step changes.

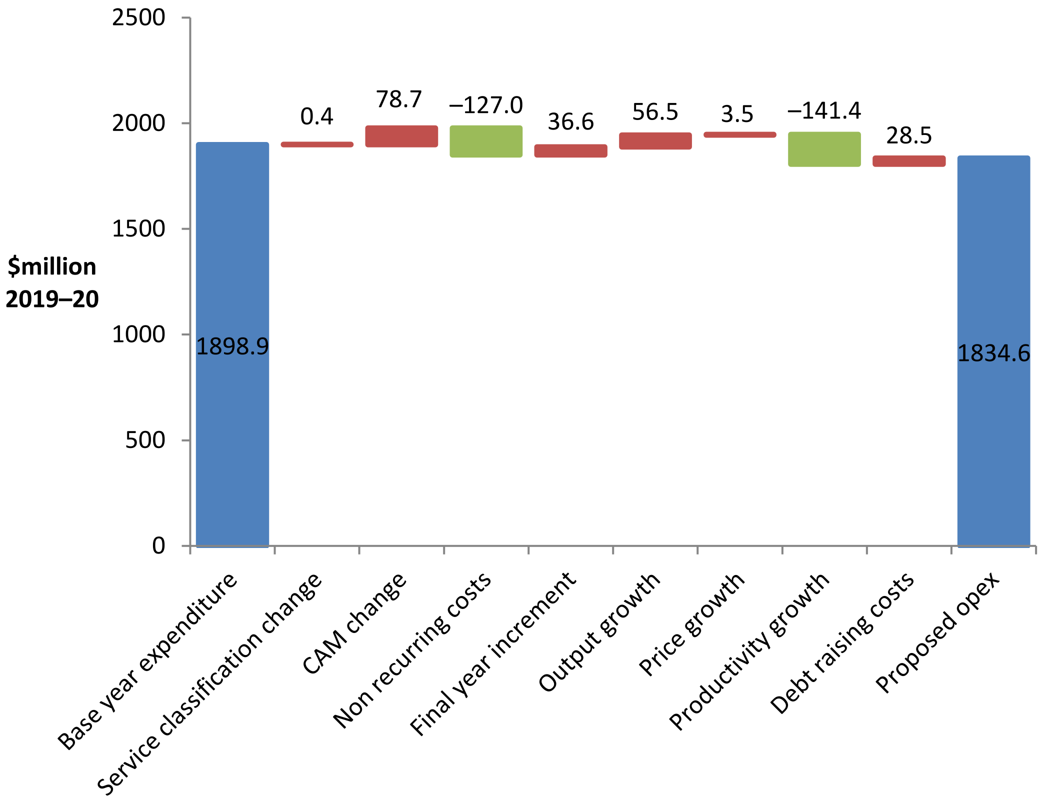
Ergon Energy has also included $28.5 million ($2019-20) of debt raising costs in its opex forecast.[84] Debt raising costs are transaction costs incurred each time debt is raised or refinanced. Our approach is to forecast an efficient level of debt-raising costs based on the cost incurred by an 'efficient' benchmark firm rather than a service provider's actual costs.

Figure 18 shows how each of these components has contributed to Ergon Energy's total opex forecast.

83 The final decision of the AER's review of forecasting opex productivity growth for electricity distributors, published 8 March 2019, set our productivity forecast at 0.5 per cent (average annual).

84 Ergon Energy – Regulatory Proposal – January 2019, pages 50-52.

Figure 18 Breakdown of Ergon Energy's opex forecast ($million, $2019-20)



Source: AER analysis.

We are interested in understanding stakeholder views as to how well Ergon Energy's forecast opex —summarised above—reasonably reflects the efficient costs of a prudent operator. We are also interested in gauging the extent to which electricity consumers consider Ergon Energy's opex forecast has addressed the concerns identified over the course of its consumer engagement program.

6 Incentive schemes

Incentive schemes are a component of incentive based regulation and complement our approach to assessing efficient costs. The incentive schemes that the AER might apply to distribution 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 about when and what type of expenditure to incur, and meet service reliability targets.

Energex and Ergon Energy have each proposed the application of our EBSS, CESS, STPIS, DMIS and DMIAM. These provide important balancing incentives 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.

6.1 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.

The EBSS has been applied to Energex and Ergon Energy during the current 2015-20 regulatory control period. Ergon Energy is forecasting an EBSS carryover amount of $268.5 million.[85] Energex is forecasting an EBSS carryover amount of $157.3 million.[86]

As part of its overall regulatory proposal, Energex and Ergon Energy are proposing to forfeit their EBSS carry over amounts and their CESS amounts (section 6.2) on the condition that the AER accepts their overall regulatory proposals.[87]

In our Final Framework and Approach paper for the Energex and Ergon Energy resets, we stated we intended to apply the EBSS to Energex and Ergon Energy in the 2020–25 regulatory control period, if we are satisfied the scheme will fairly share efficiency gains and losses between the distributors and consumers.[88] This relies on our assessing that Energex and Ergon Energy's revealed costs in the base year are not materially higher than the opex that would have been incurred by a benchmark efficient DNSP.[89] Energex and Ergon Energy support the application of the EBSS in the 2020-25 regulatory control period.

6.2 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 and Approach paper we set out our intention to apply the CESS (as set out in our capex incentives guideline[90]) to Energex and Ergon Energy in each regulatory year of the 2020−25 regulatory control period.[91]

Energex and Ergon Energy proposed that they were entitled to CESS carryover of $39.3 million and $107.0 million, respectively.[92]

However, Energex and Ergon Energy proposed to not claim its CESS (and EBSS) revenue adjustments subject to our acceptance of the regulatory proposals.

6.3 Service target performance incentive scheme

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85 Ergon Energy – Regulatory Proposal – January 2019, pages 103-104.

86 Energex – Regulatory Proposal – January 2019, pages 108-109.

87 Ergon Energy – Regulatory Proposal – January 2019, p. 103; Energex – Regulatory Proposal – January 2019, p. 106.

88 Final framework and approach Energex and Ergon Energy Regulatory control period commencing 1 July 2020-July 201, p.66.

89 Ibid.

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

91 AER, Final framework and approach Energex and Ergon Energy regulatory control period commencing 1 July 2020, July 2018, pp. 69–70

92 Ergon Energy – Regulatory Proposal – January 2019, p. 103. Energex – Regulatory Proposal – January 2019, p. 107.

Our distribution STPIS[93] 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.

In their respective revenue proposals, Energex and Ergon Energy both accepted the STPIS application approach as set out in the Framework and Approach paper but submitted that their targets will need to be adjusted as the actual performance outcome of the current regulatory period has been much better than the performance targets. As such, the reward was capped at the revenue at risk limit set under the current scheme for both distributors.[94]

When a distributor's actual performance is much better or worse than the performance targets, this may lead to a financial reward or penalty under the STPIS exceeding the revenue at risk under the scheme. In such a case, the distributor’s actual performance in a particular period must be adjusted for the purpose of setting the performance targets for the subsequent period.[95]

This is to ensure that the distributor's performance targets in the future reflect the financial reward/penalty that they have received. In particular, a distributor should not be allocated with an easy target because of historical poor performance. This is particularly so when customers have not received the appropriate compensation for poor performance. The STPIS guideline provides a standardised approach to make such adjustment that will result in a balanced outcome for both the distributor and its customers.

Energex and Ergon Energy proposed a different approach to set the adjustments to its performance targets for the forthcoming period different from the method specified in the scheme, while maintaining the principle that the outcome will be cost neutral to consumers. We are interested to hear stakeholders' views on whether Energex’s and Ergon Energy’s proposed method is reasonable.[96]

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[93] AER, *Electricity distribution network service providers - service target performance incentive scheme V2*, November 2018.

[94] Ergon Energy, Regulatory Proposal 2020-25, January 2018, Attachment 11.002 Application of Incentive Schemes, pp. 12–13; Energex, Regulatory Proposal 2020-25, January 2018, Attachment 11.001 Application of Incentive Schemes, pp. 12-13.

[95] AER, Electricity distribution network service providers - service target performance incentive scheme V2, November 2018, Appendix F.

[96] Ergon Energy, Regulatory Proposal 2020-25, January 2018, Attachment 11.002 Application of Incentive Schemes, pp. 15–16; Energex, Regulatory Proposal 2020-25, January 2018, Attachment 11.001 Application of Incentive Schemes, pp. 14–15.

6.4 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.

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.

DMIS

Energex and Ergon Energy support the new DMIS, which operates as an incentive cost uplift of up to 50 percent of expected costs of efficient demand management projects, subject to certain constraints. Energex and Ergon Energy propose that the new DMIS apply to the individual businesses during the 2020-25 regulatory control period, consistent with our proposed approach set out in the final F&A.

DMIAM

Energex and Ergon Energy support the new DMIAM as outlined in the final F&A and propose that it apply during the 2020-25 regulatory control period. Energex and Ergon Energy propose a maximum allowance of $5.58 million and $5.56 million respectively for the 2020-25 regulatory control period.

Table 5 and Table 6 set out the calculation for Energex and Ergon Energy over the forthcoming 2020-25 regulatory period.

Table 5 Proposed DMIAM allowances for Energex the 2020-25 regulatory control period

$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Average 2020-25
DMIAM	1.11	1.11	1.11	1.12	1.13	5.58

Source: Energex – 1.003 - Regulatory proposal 2020-25, p. 109

Table 6 Proposed DMIAM allowances for Ergon Energy the 2020-25 regulatory control period

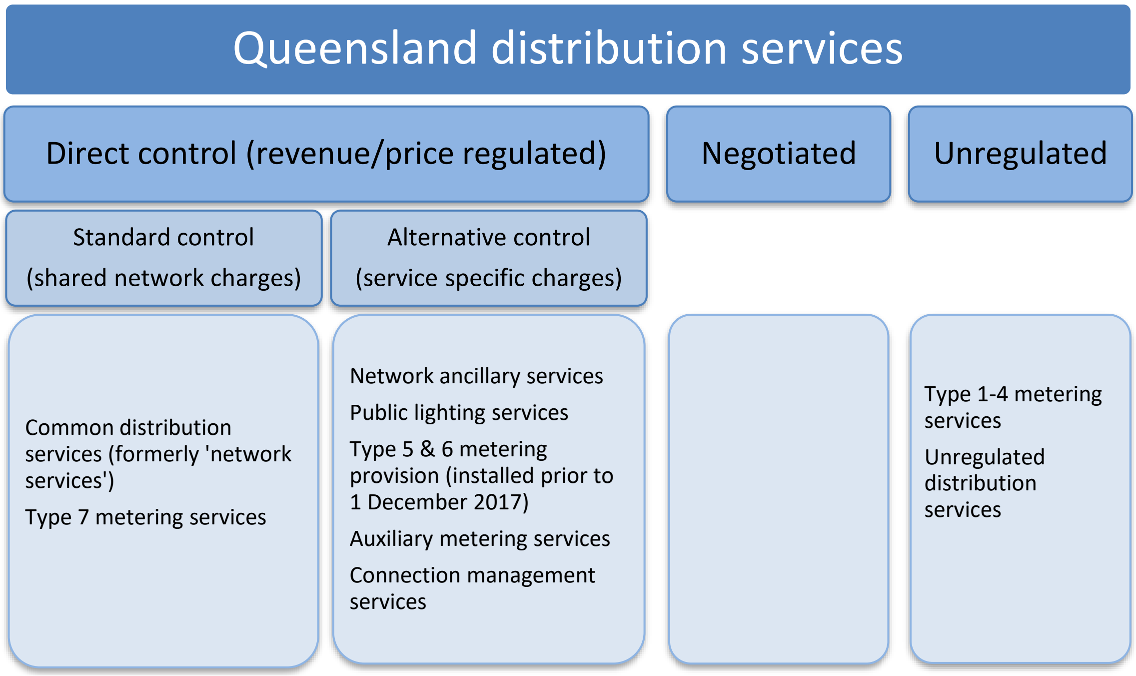
$M, Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Average 2020-25
DMIAM	1.10	1.11	1.11	1.12	1.13	5.56

Source: Ergon Energy – 1.004 – Regulatory Proposal 2020-25, p. 109.

7 Service Classification

In the Framework & Approach (F&A) paper we published last year, we set out our intended classification of the services Energex and Ergon Energy provide to their customers – summarised by Figure 19.

Figure 19 AER's proposed approach to classification of Qld distribution services



Source: AER

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. Energex and Ergon Energy have both 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 TSS proposals in section 8, 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 the direct users of those services, through a capped price on each individual service.[97]

We discuss the alternative control services proposals in section 9.

In September 2018, we published our Service Classification Guideline for electricity distribution businesses, which came into effect on 1 October 2018.[98] The Guideline sets out our approach to the classification of distribution services with the aim to provide clarity, transparency and predictability for DNSPs in the service classification process. The Guideline is not binding on distributors. However, where we depart from the Guideline we must provide reasons for doing so.[99]

Similarly, the classification of distribution services must be as set out in our final F&A unless we consider that a material change in circumstances justifies departing from that approach.[100] We consider that the release of the Service Classification Guideline, published subsequent to the final F&A for Queensland distributors, represents a material change of circumstances warranting departures from the approach to classification taken in our final F&A. The Queensland distributors agreed, requesting a number of changes to the classified services list. They also requested a departure from the Service Classification Guideline in the description of one service and the classification of one service, consistent with the approach taken in the final F&A. The departures are summarised below:

7.1 Common distribution services

The Queensland distributors agreed with the approach we took in our service classification guideline to include bulk supply point metering as part of the common distribution service. There are no changes to pricing arrangements, because these services were previously classified standard control.

7.2 Connection services

The service description for these services requested by the Queensland distributors departs from the final F&A, but is broadly consistent with the Service Classification Guideline. Brief descriptions of the various connection services have been added. For jurisdictional and operational reasons Queensland distributors propose to retain much of the classification for connection services from the final F&A, which is a departure from the Service Classification Guideline.

Enhanced connection services

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97 AER, Framework & Approach for Energex and Ergon Energy 2020-25, July 2018, p. 18.

98 https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/distribution-service-classification-guidelines-and-asset-exemption-guidelines/final-decision

99 AER, Electricity Service Classification Guideline, p.5.

100 NER cl. 6.12.3(b)

The service description differs from that in the F&A paper, but is broadly consistent with the Service Classification Guideline. The Queensland distributors have suggested an amendment to the reference to embedded generators. They consider that thresholds for embedded generators are more appropriately considered in the connection policy. There are no changes proposed to the classification.

7.3 Inspection and auditing services

This service description is consistent with that in the F&A paper, but differs to the Service Classification Guideline. In particular, consistent with jurisdictional obligations arising from section 219 and 220 of the Electrical Safety Regulation 2013 (Qld), the distributors have retained two additional activities relating to after-hours examination of consumer mains, mains switchboard, and electrical installations.[101]

The Queensland distributors support the proposed classification in the F&A, which is consistent with the baseline service list in the Service Classification Guideline.

7.4 Security lights

The Queensland distributors are proposing to adopt the description from the Service Classification Guideline. They have not proposed a change to classification.

7.5 Customer requested provision of electricity network data

The Queensland distributors are proposing to adopt the description from the Service Classification Guideline. They have not proposed a change to classification.

We are interested in stakeholder feedback on the changes to service classification that Energex and Ergon Energy have proposed, which have arisen as a result of the publication of the Service Classification Guideline.

[101] Electrical Safety Regulation 2013 (Qld), s219 & s220, p.158 - 159

8 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.[102] An indicative pricing schedule must accompany the TSS.[103] The final prices for each tariff continue to be determined on an annual basis.

8.1 The AER expectations for the upcoming TSS consultation by QLD distributors

The TSS submitted to the AER by the QLD distributors on 31 January 2019 contains a number of elements that are either unclear or subject to further consultation. The QLD distributors have committed to undertaking further consultation on their initial TSS proposal.[104]

It is important that the upcoming TSS consultation by the QLD distributors results in stakeholders having a clear understanding of the tariff reform options under consideration (including their network bill impact on customers) and that the QLD distributors appropriately take into account the feedback received during the consultation process in finalising their tariff reform proposals. It is also important that this consultation process leaves adequate time for the AER to assess whether the TSS satisfies the requirements under the NER.

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102 NER, cl. 6.18.5.

103 NER, cl. 6.8.2(d1).

104 Energy Queensland, Letter of 14 February tariff structure statement further explanation - available from: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/energex-determination-2020-25/proposal.

It is very important that the QLD distributors focus their TSS consultation process to include the following key issues:

- What should be the default network tariff for new residential and small business customers?
- Should existing customers be allowed to remain on the flat tariff even if they have a smart interval meter? If not, what should be the trigger(s) for re-assigning these customers to a cost reflective tariff?
- Should customers on a cost reflective tariff be allowed to opt-out to another tariff? If yes, what structure should this tariff have?
- Is it necessary to have transitional arrangements or safeguard measures to mitigate the customer impact of the introduction of cost reflective network prices? If yes, what transitional arrangements and/or safeguard measures should be adopted?

We are interested in the views of stakeholders on what the key issues are for the QLD distributors to address during the TSS consultation process?

We encourage the QLD distributors, when formulating their preferred position on each of these issues, to take into account the recent AER decisions on TSS proposals in other jurisdictions. The key insights from these decisions are:

- The AER will not approve the flat tariff as the default network tariff for new residential and small business customers. In other words the default network tariff must have a cost reflective structure.
- The AER considers that Time of Use and demand tariffs can be designed to be cost reflective.
- The AER believes that it is in the interests of customers for the distributor to also offer alternative cost reflective tariffs on an opt-in basis.
- To achieve an acceptable speed of transition to cost reflective pricing, the AER requires the distributor to re-assign existing customers with a smart meter to a cost reflective tariff as long as there are sufficient safeguard measures and transitional arrangements in place.

8.2 What are we trying to achieve with tariff reform in QLD?

The network pricing objective under the Rules is that the tariffs that a distributor charges in respect of its provision of direct control services (the transport of electricity through the grid) to a retail customer should reflect the distributor's efficient cost of providing those services to the retail customer. [105]

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105 NER, cl6.18.5(a)

A key principle of cost reflective tariffs is the concept of long run marginal cost. In simple terms, this is the cost to the network of an incremental change in demand for its services. The pricing principles include that each tariff must be based on long run marginal cost of providing the service to which it relates to the retail customer assigned to that tariff. [106]

If tariffs accurately reflect the marginal or forward looking cost of changes (positive or negative) in demand, then consumers can make informed and appropriate choices on whether and when to consume more or less electricity. Tariff reform seeks to promote additional investment in the network by distributors only when consumers value that increased demand more than the cost of delivering the additional network capacity necessary to meet that demand.

We are seeking the views of stakeholders on the extent that long run marginal cost should play a direct role in guiding the design of tariffs in QLD? How should this occur? We also wish to receive feedback from stakeholders on the QLD distributor’s proposed change in LRMC methodology. Do you think that this change is appropriate? Is it preferred to current industry practice of using the Average Incremental Cost (AIC) methodology?

It should also be noted that setting tariffs on the basis of long run marginal cost alone is unlikely to produce sufficient revenue for distributors to recover their total efficient costs of providing their network services, which are reflected in their annual revenue allowance. The difference between the total efficient cost and the revenue recovered from LRMC based prices is referred to as the 'residual cost'. This residual cost includes the costs relating to the existing or 'sunk' assets that are used to provide current network services. Accordingly another key principle of cost reflective tariffs is that the 'residual costs' must be recovered in a way that minimises distortions to the efficient network usage that would result from tariffs based on long run marginal cost alone. [107]

The AER notes that a key underlying driver of tariff reforms in QLD is the need to address the cross subsidies contained in existing legacy tariffs.[108] We are interested to hear whether stakeholders understand the concept of cross subsidy being used by the QLD distributors, the extent to which different customers are cross subsidising other customers and the proposed strategy of the QLD distributors to address these subsidies in the next regulatory control period.

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[106] NER, cl6.18.5(f)

[107] NER, cl6.18.5(g)

[108] Energex 2019, Energex TSS Explanatory notes 2020-25, p.14, January

9 Alternative control services

Alternative control services are services provided by Energex and Ergon Energy to specific customers. The costs of providing these services are not included in the revenue proposals we discussed in section 4. 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.

9.1 Public lighting

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

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
- whether the light is considered major or minor
- whether the light is conventional or LED.

For the 2020-25 regulatory period, both Energex and Ergon Energy have proposed using a limited building block model to generate the allowable revenue for public lighting which they then translate into tariffs. Both businesses have very limited roll-out of LEDs (1.3 per cent for Energex and 0.4 per cent for Ergon Energy as at March 2018)[109] and are planning to increase the roll-out of LEDs so as to achieve 47 per cent LED penetration by 2025.[110] As part of this, the businesses are proposing to introduce specific LED versions of the existing public lighting tariffs, as well as a new LED specific tariff.[111] Energex will also be changing its method of apportioning revenue to be consistent with Ergon Energy.[112]

9.2 Metering

[109] AER calculations based on Energy Queensland, *15.004 Public Lighting Strategy*, October 2018, p. 11.

[110] Energy Queensland, *1.005 An overview – our regulatory proposal 2020*-25, January 2019, p. 54.

[111] Energex, *15.005 Alternative Control Services 2020-25*, January 2019, pp. 19-20; *Ergon Energy – 15.006 - Alternative Control Services 2020-25*, January 2019, pp. 18-9.

[112] Energex, *15.005 Alternative Control Services 2020-25*, January 2019, p. 19.

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 primary; controlled load; and solar PV tariffs.

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 are to be smart meters – as a minimum, a Type 4
- 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.[113]

As a result of the Power of Choice reforms, Energex and Ergon Energy are no longer responsible for installing new meters or replacing them when they fail.[114] Their proposals do not include any new capital expenditure for installing and replacing meters (direct metering capex), except for Ergon Energy's Mount Isa-Cloncurry network.

Energex and Ergon Energy have proposed indirect metering capex, including IT systems and meter testing equipment to meet remaining type 6 metering obligations.[115] We will consider the appropriateness of these estimates. While type 6 metering opex costs per customer are trending downwards slowly, the total cost per meter is increasing, which is to be expected as fixed costs need to be spread over a smaller customer base. Both businesses have proposed continuing to apply a capital charge to customers who shift to a contestable metering provider.

Table 7 details the metering opex per customer proposed by each business.

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[113] 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 interval meters (type 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 a declining capital charge reflecting the steadily diminishing value of unrecovered metering investment.

[114] Except for Ergon's Mount Isa-Cloncurry supply network.

[115] Energex, *15.005 Alternative Control Services 2020-25*, January 2019, p. 6; *Ergon Energy – 15.006 - Alternative Control Services 2020-25*, January 2019, p. 6.

Table 7 Proposed metering opex per customer ($2019–20)

		2020-21	2021-22	2022-23	2023-24	2024-25
Energex	Forecast customer numbers	1,270,620	1,246,097	1,222,048	1,198,462	1,175,332
	Metering opex per customer	15.12	15.01	14.92	14.85	14.78
Ergon Energy	Forecast customer numbers	622,552	591,051	561,144	532,750	505,793
	Metering opex per customer	46.40	44.81	43.45	42.24	41.16

Sources: AER Analysis; EGX ERG 15.028 Metering Pricing model - ACS JAN19 PUBLIC; Ergon Energy, 17.045 Metering ACS supporting information (Reset RIN schedule 1 s15), p. 11; Energex, 17.044 Metering ACS supporting information (Reset RIN schedule 1 s15), p. 9.

9.3 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, to conduct an independent review of the labour costs and estimated times to perform the most commonly demanded ancillary services for Energex and Ergon Energy.

Both Energex and Ergon Energy have proposed a cost build up model for fee-based and quoted services, including the addition of a 'capital allowance' which has been defined as:

> a return on and return of capital for non-system assets (for example vehicles, IT and tools) used in the provision of the service.[116]

While our Framework & Approach proposed a price cap formula for quoted services without this component, we did approve its inclusion in our 2015-20 decision.[117]

[116] Energex, 14.001 2020-25 Tariff Structure Statement JAN 19 Public, p. 40; Ergon Energy, 14.002 2020-25 Tariff Structure Statement JAN 19 Public, p. 43.

In terms of fee-based services, we will analyse proposed prices with regard to our consultant's report on labour rates and consider how a 'capital allowance' falls within this.

[117] For example: AER, *Final Decision – Energex determination 2015-16 to 2019-20 – Attachment 16 – Alternative Control Services*, October 2015, p. 16-10.

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.[118] 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.[119] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[120]

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.[121] 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.[122]

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.[123] 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.[124] 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.[125] 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 maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable.[126] 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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118 NEL, section 16(1).

119 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.

120 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.

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

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

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

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

125 NEL, s. 7A(7).

126 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 judgments 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 judgment. 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, [127] 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.[128]

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.

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

[128] NEL, s. 16(1)(d).