Ergon Energy Revised Regulatory Proposal 2020-25

December 2019

ERGON ENERGY NETWORK

Contents

Executive Summary

We exist to provide electricity distribution services to our fellow Queenslanders. Over the past year, we have engaged our community stakeholders, customers and industry partners to better understand what they need, value and expect from us. We have heard that our customers want us to 'safely deliver affordable, secure and sustainable energy solutions'. This Revised Regulatory Proposal details how we will deliver these outcomes from 1 July 2020.

Snapshot of our revised proposal

The key aspects of our Revised Regulatory Proposal for the 2020-2025 regulatory control period are summarised below.

Table 1 Forecast summary 2020-21 to 2024-25

	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Standard control services						
Forecast expenditures ($M, Real $2020)						
Net capex	552.34	570.59	583.38	552.89	557.62	2,816.80
Opex (including debt raising costs)	376.83	371.57	367.00	362.06	357.17	1,834.63
Opening RAB ($M, Nominal)	11,513.23	11,908.30	12,316.91	12,736.94	13,126.01	
Revenue Requirements ($M, Nominal)						
Return on Capital (WACC 4.67%)	538.06	540.71	542.91	544.51	543.71	2,709.90
Regulatory Depreciation	176.67	195.65	212.02	223.74	243.44	1,051.53
Opex (including debt raising costs)	385.76	389.40	393.72	397.62	401.55	1,968.04
Incentive Schemes and other Revenue Adjustments	68.01	62.43	76.18	28.41	25.19	260.22
Corporate Tax Allowance (Gamma 0.585)	-	-	-	-	-	-
Annual Revenue Requirements (smoothed)	**1,143.96**	**1,171.07**	**1,198.82**	**1,227.23**	**1,256.32**	**5,997.40**
X Factor (note – positive value reduces revenue) (%)	13.60%	0.00%	0.00%	0.00%	0.00%	13.60%
Demand - Forecast 50POE (MW)	2,544.78	2,536.49	2,532.72	2,549.14	2,564.24	
Customer numbers	744,049	751,961	759,601	767,234	774,870	
Forecast energy consumption (GWh)	13,453.83	13,434.06	13,389.05	13,406.40	13,329.86	67,013.20
Alternative control services						
Metering annual revenue requirement (unsmoothed) - ($M, Nominal)	47.38	45.55	43.88	42.34	40.94	220.09
Public lighting annual revenue requirement (unsmoothed) - ($M, Nominal)	25.61	26.24	26.92	27.82	28.96	135.55

Totals may not add due to rounding.

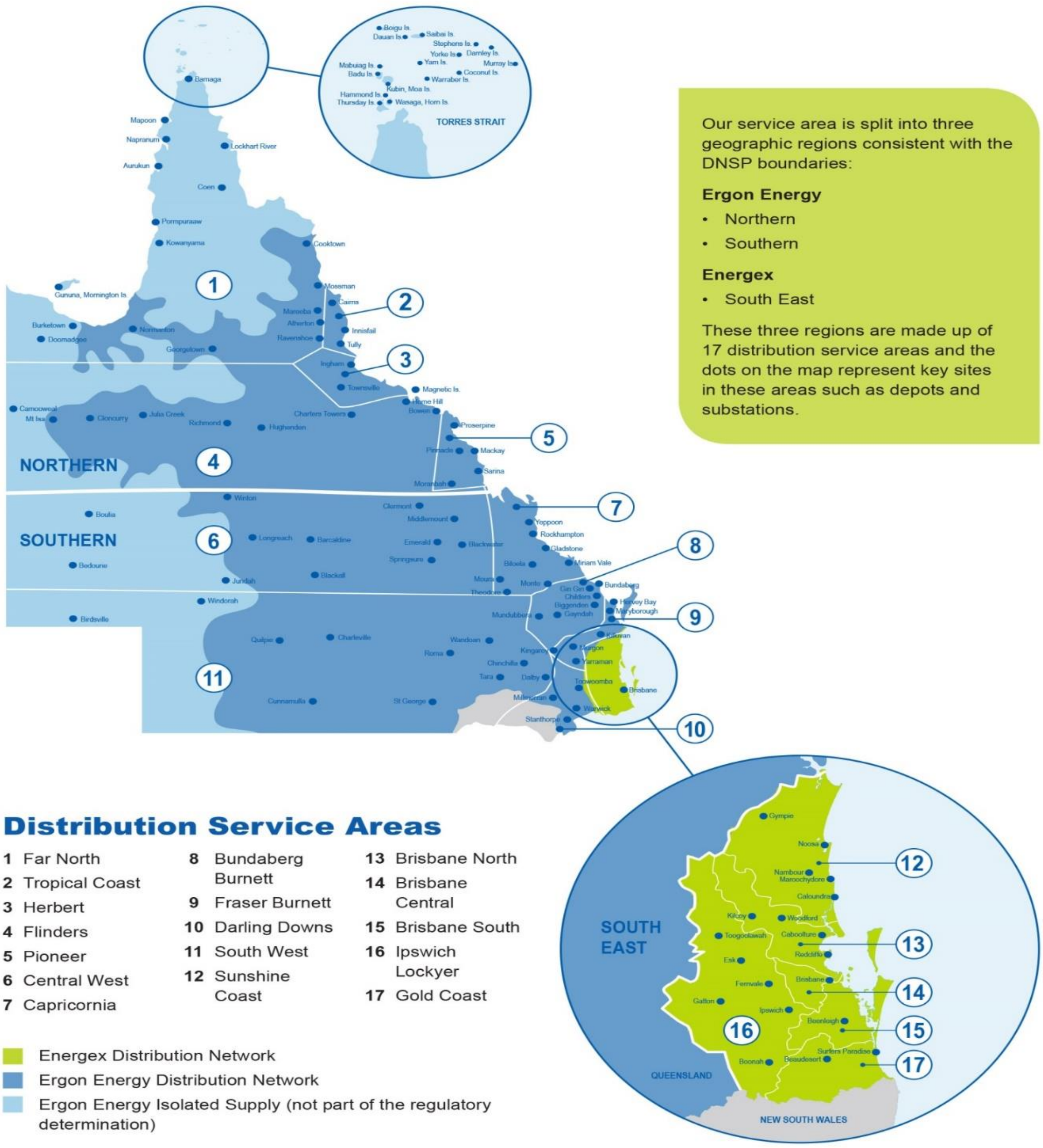
1. About us and this Revised Regulatory Proposal

1.1 About us

We provide our distribution services to more than 750,000 households and businesses throughout Queensland, except for the South East corner, geographically accounting for 97% of Queensland. We must maintain enough capacity in our distribution network to supply every household and business on the days when electricity demand is at its maximum, no matter where they are. We are proudly part of Energy Queensland, a Queensland Government owned organisation.

The communities we serve, our customers and other stakeholders, want an affordable, secure and sustainable electricity supply today, and into the future. To deliver this across the breadth and length of Queensland, we are committed to listening and acting on this feedback and continuing to engage with our communities, customers and stakeholders as we move forward.

Figure 1 – Geographic coverage



1.2 Why a Revised Regulatory Proposal is required

To ensure we manage the distribution network efficiently and in the best interests of our community and customer interests, Ergon Energy is regulated under the National Electricity Rules (NER) by the AER. It is the AER's role to cap the revenues we are allowed and regulate the amount we can recover through our distribution network charges. These are set in five-year periods, with our next regulatory control period starting on 1 July 2020.

The distribution network charges, for the access to and supply of electricity via the distribution network, are incorporated into retail electricity bills across Queensland. These are known as our Standard Control Services (SCS) and, unless specified, this document refers to these services. Several other customer specific and asset specific services and charges are separately regulated as Alternative Control Services (ACS).

We have prepared this Revised Regulatory Proposal in accordance with clause 6.10.3 of the NER. The AER will respond to our Revised Regulatory Proposal with its Final Determination in April 2020. The AER's Draft Decision, released in October 2019, was preceded by our publication of Our Draft Plans, our initial Regulatory Proposal, and an extensive period of stakeholder consultation. This Revised Regulatory Proposal details our acceptance of elements of the AER's Draft Decision and provides our justifications and modifications in other areas. This Revised Regulatory Proposal builds on our earlier Regulatory Proposal, incorporating input from community stakeholders, end use customers and industry partners. It also considers new information available as part of our business as usual asset management processes.

In preparing for 2020 and beyond, and in order to ensure we are best placed to deliver for all Queenslanders, we have continued to focus on ensuring our capital investment and operating plans are prudent and efficient and that our tariff reforms provide better outcomes.

Since the submission of our Regulatory Proposals in January 2019, we have continued to engage with our communities and customers to help inform our revisions to expenditure, revenue and tariff proposals. While there have been changes outside of our control in terms of the revenue allowance, with the AER's support for our revised proposals we are confident that our plans will enable us to deliver a bright energy future for Queensland.

1.3 Summary of changes

This Revised Regulatory Proposal has been prepared in response to the AER's Draft Decision and has been informed by a balanced view of business and network sustainability and safety as well as the preferences of our communities and customers. A summary of changes is presented in Table 2.

Table 2 Summary of changes

Item	Unit	Regulatory Proposal	AER Draft Decision			Revised Regulatory Proposal		
		Forecast	Forecast	Difference from RP	%	Forecast	Difference from RP	%
Revenue and pricing								
Revenue (smoothed)	$m nominal	6,515.77	5,787.89	-727.87	*-11.17%*	5,997.40	-518.36	*-7.96%*
P_0 (initial price decrease in 2020/21)	%	9.44%	16.82%	7.38%	*78.18%*	13.60%	4.16%	*44.10%*
X-factor (annual price change in remaining years)	% p.a.	0.00%	0.00%	0.00%	*0.00%*	0.00%	0.00%	*0.00%*
Building blocks								
Return on capital	$m nominal	3,346.29	2,806.91	-539.39	*-16.12%*	2,709.90	-636.39	*-19.02%*
Operating expenditure (inc debt raising)	$m nominal	1,971.91	1,972.69	0.77	*0.04%*	1,968.04	-3.87	*-0.20%*
Depreciation	$m nominal	1,052.31	997.39	-54.92	*-5.22%*	1,051.53	-0.78	*-0.07%*
Tax	$m nominal	143.97	0.60	-143.37	*-99.59%*	-	-143.97	*-100.00%*
Revenue adjustment	$m nominal	5.98	5.47	-0.51	*-8.55%*	260.22	254.24	*4249.20%*
Key inputs								
Average annual growth in peak demand	%	0.38%	0.38%	0.00%	*0.00%*	0.15%	-0.22%	*-59.16%*
Incentive schemes (EBSS and CESS)	$m real 2019-20	307.84	202.75	-105.09	*-34.14%*	240.06	-67.78	*-22.02%*
Net New customers	customers	60,000	60,000	-	*0.00%*	36,000	-	*0.00%*
Inflation	%	2.42%	2.45%	0.03%	*1.24%*	2.37%	-0.05%	*-2.07%*
Rate of return (WACC)	%	5.46%	4.87%	-0.59%	*-10.84%*	4.67%	-0.79%	*-14.39%*
Net capital expenditure	$m real 2019-20	2,724.24	2,150.91	-573.33	*-21.05%*	2,816.80	92.56	*3.40%*
RAB per customer (current forecast)	$ real 2019-20 per customer	15,521.36	14,744.56	-776.80	*-5.00%*	15,513.85	-7.51	*-0.05%*

Totals may not add due to rounding. All customer numbers in the RRP have been updated to align with the new QCA forecasting method.

Our Revised Regulatory Proposal improves upon our Regulatory Proposal revenue reduction to deliver a 13.60% reduction in revenue from 2019-20 to 2020-21. While we continue to look for ways to make our business more efficient and have provided a proposal that is capable of acceptance, our number one priority is safety.

Compared to the current regulatory control period (2015-20), the next regulatory control period (2020-25) will see a 14% reduction ($790.33 million in real $2019-20) in our overall smoothed revenue requirement. Ergon Energy's Revised Regulatory Proposal revenue also represents a 8% reduction from the revenue requirement contained in our Regulatory Proposal.

The reduction in our revenue requirement translates directly into lower tariffs for our customers. The average Ergon Energy residential and small business customer will receive a real reduction of 15.4% in network charges. The Queensland Government Customer Service Obligation (CSO) means that the average residential and small business customer on notified retail prices will pay no more than the average residential and small business customer on default tariffs in South East Queensland.

Ergon Energy residential customers with a digital meter who choose to move to a new cost reflective tariff could save up to 17.6% while small businesses could save up to 20.0% on the network component of their bill.

Our Tariff Structure Statement details the impact of our proposed revenue on the various Ergon Energy tariff categories. It also introduces new tariff categories that provide opportunities for customers to further reduce the network tariff portion of their electricity bill.

1.4 How to provide feedback

The AER will consult on our Revised Regulatory Proposal and publish its Final Determination by the end of April 2020, with new pricing applying from 1 July 2020. Throughout this process we will continue to engage with our customers and other stakeholders on our plans, including through our Customer Council and our website, www.talkingenergy.com.au, where all of our existing consultation material is available.

Questions can be directed to us via regulatoryproposal@energyq.com.au or you can provide feedback to the AER at http://www.aer.gov.au

1.5 Supporting documentation

The following documents supporting this chapter:

Name	Ref	File Name
An Overview Our Revised Regulatory Proposals 2020-25	1.001	EGX ERG 1.001 An Overview Our Revised Regulatory Proposals 2020-25 DEC19 PUBLIC
Document Register	1.002	ERG 1.002 Document Register DEC19 PUBLIC
2020-25 Revised Regulatory Proposal	1.003	ERG 1.003 2020-25 Revised Regulatory Proposal DEC19 PUBLIC
Confidentiality template	1.004	ERG 1.004 Confidentiality template DEC19 PUBLIC

2. Our Revised Regulatory Proposal

In preparing its Draft Decision, the AER took three key factors into account:

- Ensuring that customers pay no more than they need for safe and reliable services
- Our engagement with consumers
- Recognition that an evolving electricity system requires investment.

The AER's Draft Decision stated that "*in order to accept Ergon Energy's proposal we will need further justification and supporting material"*. This Revised Regulatory Proposal revisits certain areas of our Regulatory Proposal and provides additional justification and supporting material to enable the AER's acceptance.

This Revised Regulatory Proposal is structured as follows:

- **Chapter 3** covers the **Customer Engagement** we have undertaken in preparation of this Revised Regulatory Proposal. It details the delivery drivers for our business.
- **Chapter 4** provides the **Revised Annual Revenue Requirements** and establishes our opening Regulatory Asset Base (RAB) for our Standard Control Services (SCS). We show the application of depreciation, indexation and capital expenditure (capex) in the calculation of the RAB for the 2020-25 regulatory control period.
- **Chapter 5** updates our **Demand forecast**
- **Chapter 6** explains our revised **Capital expenditure** and provides references to the resubmitted business cases.
- **Chapter 7** details our **Revised operating expenditure** using the base-step trend methodology.
- **Chapter 8** provides the **Rate of return, inflation, debt and equity raising** assumptions used in our revised proposal.
- **Chapter 9** covers the operation and outcomes of the **Incentive schemes**.
- **Chapter 10** briefly covers **Other constituent decisions** associated with the regulation of our business.
- **Chapter 11** provides our revised proposal for **Alternative control services** (ACS) which incorporates public lighting, metering, ancillary (fee-based and quoted) services and security lights.

Further information about our future investment plans is available in the supporting documents we have submitted to the AER with this Revised Regulatory Proposal. As with our January 2019 submission, where possible supporting information covering both Energex and Ergon Energy has been provided in a single document. Where we have not detailed a change in approach, we continue to rely upon the material and approach contained in our original Regulatory Proposal for the 2020-25 regulatory control period.

We have adopted the "Accept, Modify and Justify" approach in our Revised Regulatory Proposal as follows:

- **Accept**: We accept the AER Draft Decision on the basis that the AER has accepted our forecast as per our Regulatory Proposal or because the substituted forecast is acceptable to us

- **Modify:** Based on the feedback from the AER, we are modifying our forecast to either change the project scope (e.g. where an alternative option is acceptable) or vary the forecast costs. This includes projects or programs where new information has become available since the submission of our Regulatory Proposal in January 2019 (e.g. increase in known safety defects)
- **Justify:** We maintain the forecast capex as set out in the Regulatory Proposal were prudent and efficient and are re-submitting our business cases with additional evidence to justify the needs

3. Customer Engagement

Energy Queensland has provided an overview document as a quick guide to the Revised Regulatory Proposals and Revised Tariff Structure Statements (TSSs) for both Ergon Energy and Energex. We have also updated the 2020 and beyond Community and Customer Engagement report which describes the engagement program we undertook with our stakeholders and details how this Revised Regulatory Proposal meets our customer commitments. We understand our customers:

- want us to listen to and act on their feedback, clearly showing how it has informed our decisions
- want us to provide affordable, secure and sustainable electricity.

We will continue to engage with our customers and other stakeholders as the AER prepares its Final Determination for the 2020-25 regulatory control period.

The overview document details our extensive engagement program where we listened to our community stakeholders, customers, and industry partners to better understand what matters to them as we prepared this Revised Regulatory Proposal. It includes the messages we heard from these stakeholders and our responding actions.

Figure 2 provides our customer commitments, where we balance the requirement to ensure safety with the competing objectives of affordability, security and sustainability.

Figure 2 Our customer commitments

3.1 Safety

Safety is our overarching commitment to our communities, customers and employees. This is a non-negotiable element of our investment plans and how we work. New technology will help to improve safety and performance, while managing affordability.

Our engagement program highlighted that stakeholders recognise the importance of safety and they:

- recognise the dangers of electricity and that, if it is not managed appropriately, our distribution network presents a physical risk to our staff and the public
- are generally happy with the current safety of the network as well as our approach to maintaining safety for our communities, customers and staff
- recognise the value of investing in new technologies, such as low voltage monitoring devices, which can enhance customer safety.

3.2 Affordability

Our engagement program highlighted that affordability remains a core concern for many customers. Our Revised Regulatory Proposal reduces our proposed allowed revenue providing for even larger reductions in distribution network charge than were included in our Proposed TSS. This has been made possible by our ongoing commitment to constrain costs and operate our business efficiently, the reduction in the Weighted Average Cost of Capital (WACC) and a new method of calculating regulatory tax.

The overview document steps through the affordability outcomes for customers and provides context around how we have balanced our affordability objective with the changing operating and market conditions.

3.3 Security

We have legislative and regulatory obligations to maintain the safety and reliability of our network services. Our customers have told us that they are generally happy with the current level of safety and reliability, and that they value us “being there for the community after the storm”. We have modified our operations and resubmitted the business cases to support our capex expenditure to ensure that we have the funds necessary to maintain power reliability, while targeting expenditure savings and improving outcomes where network outages are outside of our service standards.

3.4 Sustainability

The manner in which our customers source and use energy, and monitor their energy needs, are all rapidly changing. Our customers want greater choice and control over their energy solutions. We are looking to the future and evolving into a network that enables customer choice and the associated adoption of new, emerging technologies. We continue to utilise demand management and embedded generation options when optimising our investment program. We are facilitating customer choice in metering and have proposed separate tariffs for Light Emitting Diode (LED) public lights.

3.5 Supporting documentation

The following documents supporting this chapter:

Name	Ref	File Name
Customer Engagement Summary - 2020-25 Revised Regulatory Proposals	3.001	EGX ERG 3.001 Customer Engagement Summary - 2020-25 Revised Regulatory Proposals DEC19 PUBLIC

4. Revised Annual Revenue Requirements

The Annual Revenue Requirement (ARR) represents the amount of revenue we require over the 2020-25 regulatory control period to allow us to invest in, operate and maintain our network (i.e. provide standard control services). The NER stipulates that the ARR is calculated using the AER's post-tax revenue model (PTRM) by summing up the following building block costs for each year

- Return on capital (financing costs)
- Return of capital or Regulatory Depreciation (payback of the RAB)
- Forecast opex
- Forecast tax allowance
- Other revenue adjustments.

The ARR is then smoothed to reduce fluctuations between years across the regulatory period.

Our Revised Regulatory Proposal proposes total revenue of $5,587 million (real $2019-20) over the 2020-25 regulatory control period. This is 6% lower than our initial Regulatory Proposal but 6% higher than the Draft Decision. Table 3 shows the nominal annual revenue requirement for the 2020-25 regulatory control period.

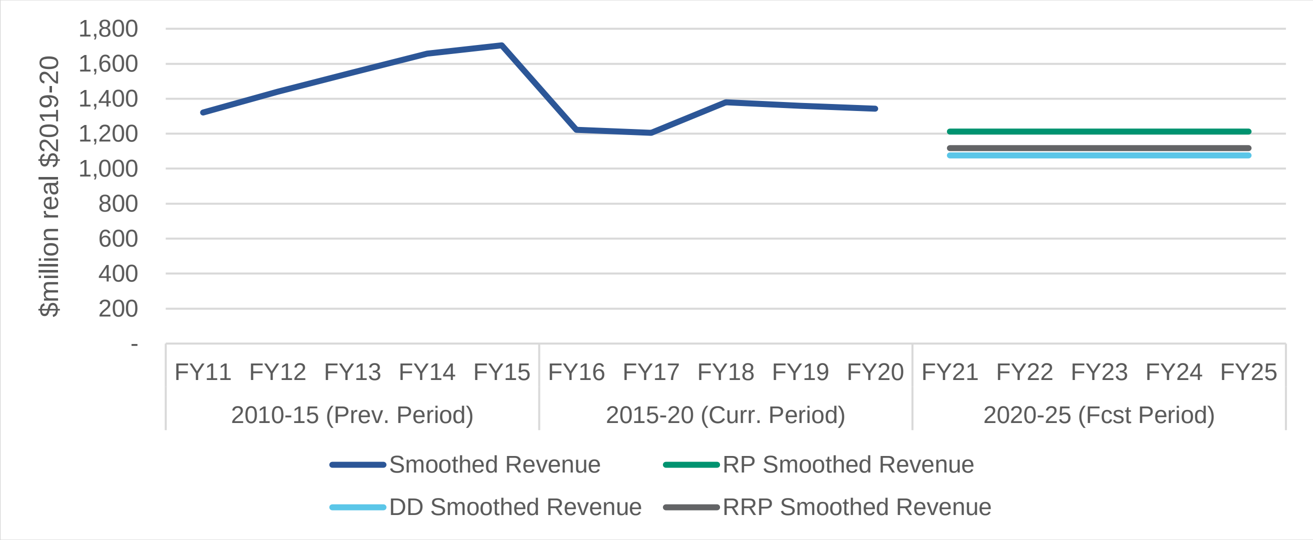
Table 3 Annual revenue requirement

$million nominal	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Return on capital	538.06	540.71	542.91	544.51	543.71	**2,709.90**
Return of capital (Regulatory depreciation)	176.67	195.65	212.02	223.74	243.44	**1,051.53**
Opex	385.76	389.40	393.72	397.62	401.55	**1,968.04**
Tax allowance	-	-	-	-	-	**-**
Revenue adjustment	68.01	62.43	76.18	28.41	25.19	**260.22**
Annual revenue requirement	1,168.51	1,188.19	1,224.83	1,194.27	1,213.88	**5,989.69**
Smoothed annual revenue	1,143.96	1,171.07	1,198.82	1,227.23	1,256.32	**5,997.40**
X-factors	13.60%	0.00%	0.00%	0.00%	0.00%	**13.60%**

A positive x-factor indicates a reduction in annual revenue

Our proposed regulated revenue is lower than at any other time that we have been regulated by AER as shown in Figure 3.

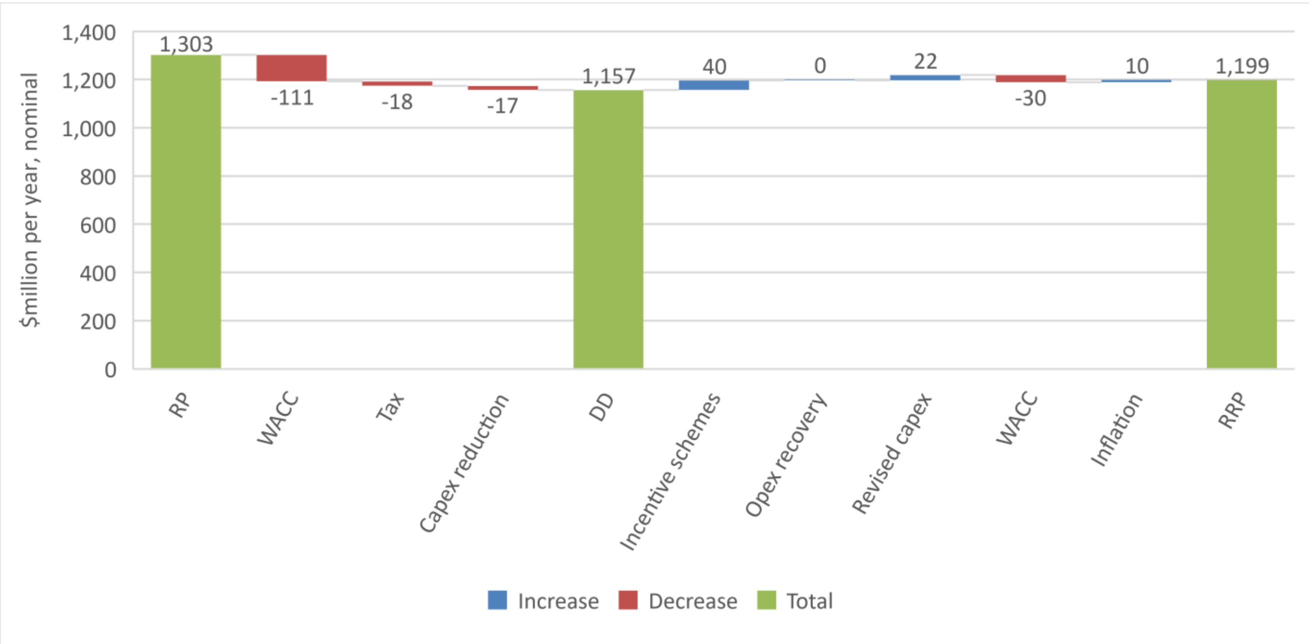
Figure 3 Revenue trend



The main drivers of the revenue differences between the Regulatory Proposal, Draft Decision and our Revised Regulatory Proposal are highlighted in Figure 4. Significant changes in the financial markets, which have reduced our allowed rate of return, and changes to regulatory treatment of taxation were the primary drivers of the significant reduction in our forecast revenue in the Draft Decision.

Differences between the Draft Decision and our Revised Regulatory Proposal reflect the significant changes in our financial and operational circumstances. We have had to recalibrate the affordability commitments that we included in our Regulatory Proposal. We have included the incentives schemes revenues which we had previously elected to forgo (discussed in Chapter 9) while retaining our opex forecasts (discussed in Chapter 7). We have also revised our capex program (discussed in Chapter 6) and updated the forecast allowed rate of return (discussed in Chapter 8).

Figure 4 Revenue driver waterfall from RP to RRP ($million nominal, average annual revenue)



Note: This chart covers SCS revenue only. Some revenue drivers affect multiple building blocks, so approximations were used to allocate the revenue change between the Regulatory Proposal and the Revised Regulatory Proposal across the revenue drivers

In the sections that follow, we set out our revised RABs, regulatory depreciation, tax allowances and other revenue adjustments.

4.1 Regulatory asset base

4.1.1 Opening RAB as at 1 July 2020

We have accepted changes proposed by the AER in its Draft Decision and have updated our calculations of the opening RAB to incorporate these amendments and the latest Consumer Price Index (CPI) information. Table 4 sets out our revised opening RAB.

Table 4 Revised opening RAB

$million nominal	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
Opening RAB	9,872.98	10,217.02	10,489.79	10,803.30	11,146.07	
Straight-line depreciation	-434.10	-387.70	-393.65	-409.79	-423.65	
Indexation	166.71	150.80	200.26	192.74	189.48	
Capex	611.43	509.66	506.90	559.82	550.07	
Closing RAB	10,217.02	10,489.79	10,803.30	11,146.07	11,461.96	
Adjustment for previous regulatory control period					-69.91	
Legacy ICT assets					121.17	
Opening value as at 1 July 2020						11,513.23

Totals may not add due to rounding.

The Draft Decision largely accepted our proposed methodology for calculating the opening RAB as at 1 July 2020. The AER approved a value of $11,552.8 million, which was $81.3 million (0.7%) lower than our proposal because of several revisions made to our proposed inputs in the roll forward model (RFM) including:

- CPI for 2014-15
- Movements in capitalised provisions
- Updates for newer information such as:
  - actual CPI input for 2018–19 and updated inflation estimate for 2019–20
  - weighted average cost of capital (WACC) input for 2019–20 following the return on debt update for that year in the 2015–20 post-tax revenue model (PTRM)
  - forecast straight-line depreciation for 2019–20 following the return on debt update for that year in the 2015–20 PTRM.
- The value of legacy ICT assets as at 1 July 2020.

4.1.2 Forecast RAB over the 2020-25 regulatory control period

Our Revised Regulatory Proposal updates the calculation of our forecast RAB over the 2020-25 period. The updated elements of our Revised Regulatory Proposal that affect the forecast RAB include:

- opening RAB at 1 July 2020
- capex forecasts
- rate of return
- expected inflation.

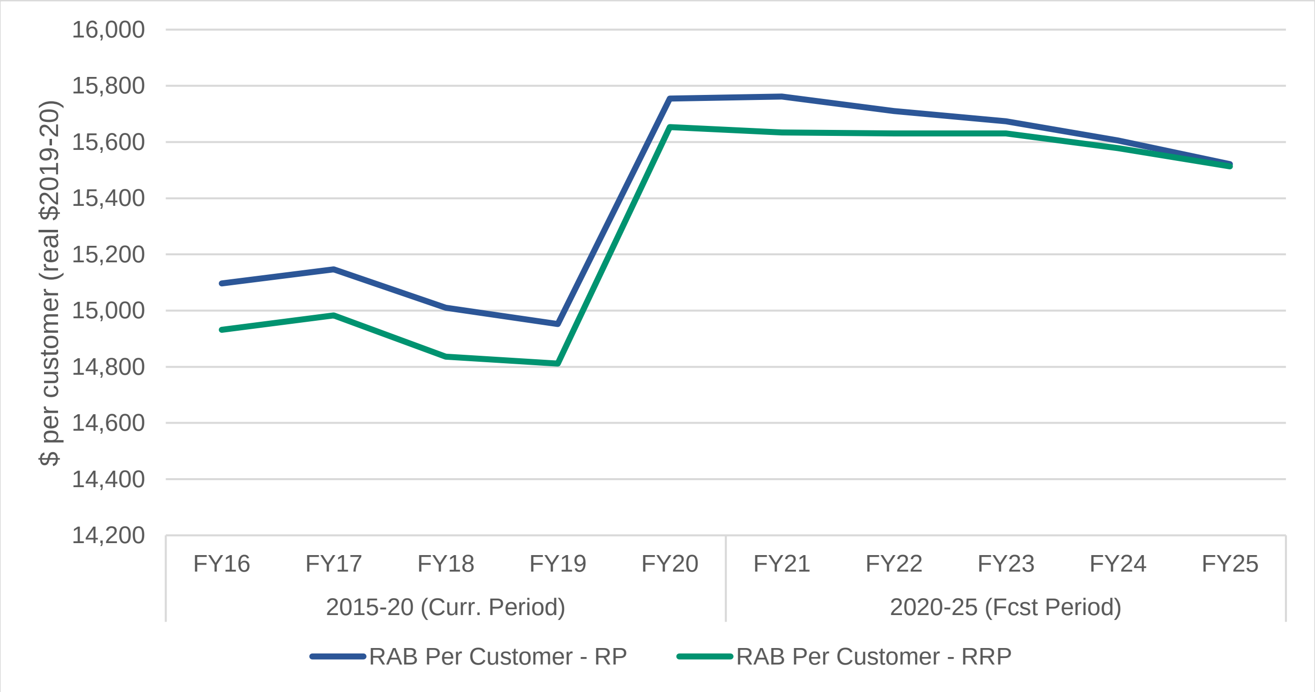
Table 5 RAB for the 2020-25 regulatory control period ($ million, nominal)

$M, nominal	2020-21	2021-22	2022-23	2023-24	2024-25
Opening RAB	11,513.23	11,908.30	12,316.91	12,736.94	13,126.01
Net Capex	571.75	604.26	632.04	612.82	632.31
Straight-line depreciation	-449.54	-477.88	-503.93	-525.61	-554.53
Indexation	272.86	282.23	291.91	301.87	311.09
Closing RAB	11,908.30	12,316.91	12,736.94	13,126.01	13,514.88

Totals may not add due to rounding.

Our proposed capex increases our RAB in nominal terms across the 2020-2025 regulatory control period, however Figure 5 shows that in real terms on a per customer basis, the RAB is declining throughout the period. The increase in the RAB per customer at the start of the period is a result of the legacy ICT assets being added.

Figure 5 Real RAB per customer



4.2 Regulatory depreciation

Our Revised Regulatory Proposal updates the calculation of regulatory depreciation. The updated elements of our proposal that affect regulatory depreciation allowances include:

- opening RAB at 1 July 2020
- capex forecasts
- rate of return
- expected inflation.

The Draft Decision accepted our proposed:

- use of the straight-line depreciation method
- use of the year-by-year tracking approach but made some minor amendments to our calculations
- existing asset classes but removed redundant asset classes (i.e. communications, easements and research and development)
- standard asset lives – except for Equity raising costs
- inclusion of a legacy ICT asset class, with a 10-year asset life.

We accept the Draft Decision in this regard. Table 6 sets out our revised regulatory depreciation calculations.

Table 6 Depreciation

$M, nominal	2020-21	2021-22	2022-23	2023-24	2024-25
Straight-line depreciation	449.54	477.88	503.93	525.61	554.53
Indexation	272.86	282.23	291.91	301.87	311.09
Regulatory depreciation	**176.67**	**195.65**	**212.02**	**223.74**	**243.44**

Totals may not add due to rounding.

4.3 Estimated cost of corporate tax allowance

Our Revised Regulatory Proposal forecasts nil tax allowances for the 2020-25 regulatory control period. Our tax allowances have been reduced to zero for two reasons. Firstly, our revenues have materially fallen as a result of the decline in the allowed rate of return. Secondly, in April 2019, after we had submitted our Regulatory Proposal in January 2019, the AER completed the implementation of the outcomes of its 2018 regulatory tax review with the publication of version 4 of the PTRM. The calculation of our tax allowances in the PTRM was adversely impacted by the following two changes in the AER's approach:

- **immediate expensing of capex –** allowing for certain capex to be immediately expensed when estimating the benchmark tax expense. For the purpose of forecasting the AER uses an 'actual informed approach' to determine the expensing of capex. Our current practise of expensing capitalised overheads therefore materially reduces our tax allowances.

- **diminishing value depreciation method –** applying the diminishing value (DV) method for tax depreciation purposes to all new depreciable assets except for capex associated with in-house software, equity raising costs and building.

4.4 Revenue adjustments

In addition to asset costs (financing and depreciation), opex and tax allowances, our building blocks also include revenue adjustments for incentive schemes (discussed in Chapter 9) and shared assets. These are set out in Table 7.

Table 7 Revenue adjustment

$M , Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25
CESS	9.23	9.23	9.23	9.23	9.23
EBSS	56.15	49.29	60.72	15.61	12.16
DMIA	1.07	1.06	1.07	1.03	1.02
Shared assets	-	-	-	-	-
Total	**66.44**	**59.57**	**71.01**	**25.87**	**22.40**

Totals may not add due to rounding.

As shown in Table 7, our Revised Regulatory Proposal forecasts no shared assets revenue as our shared assets revenue remains under the 1% materiality threshold. We note that the Draft Decision requires our Revised Regulatory Proposal to provide an update on the impact on forecast shared assets revenues from the July 2019 announcement by the Queensland Government that Powerlink and Energy Queensland will jointly operate a new optic fibre network business, QCN Fibre (previously FibreCo). As we previously advised the AER and its Consumer Challenge Panel (CCP), we do not currently expect an increase in the scope or volume of unregulated services using shared assets that we provide as a result of the formation of QCN Fibre. Initially, customer contracts (for services *currently* provided by Powerlink and to a lesser extent Energex and Ergon Energy) are being novated to QCN Fibre. Any increased activity on our network over and above existing arrangements being novated are expected to be insignificant in the short to medium term and subject to high levels of uncertainty over the longer term.

4.5 Supporting documentation

The following documents supporting this chapter:

Name	Ref	File Name
RAB Depreciation Model	4.001	ERG 4.001 RAB Depreciation Model DEC19 PUBLIC
PTRM – SCS	4.002	ERG 4.002 PTRM – SCS DEC19 PUBLIC
RFM – SCS	4.003	ERG 4.003 RFM – SCS DEC19 PUBLIC

5. Demand forecast

During 2018, we developed a new, improved system peak demand forecasting model for the forward 10-year period. This model was used in our 2019 forecast using the recorded 2018/19 summer peak demand at our substations. Substation peak demand forecasts are reconciled with the system peak demand forecasts to ensure economic drivers at the state level are integrated into the substation forecasts.

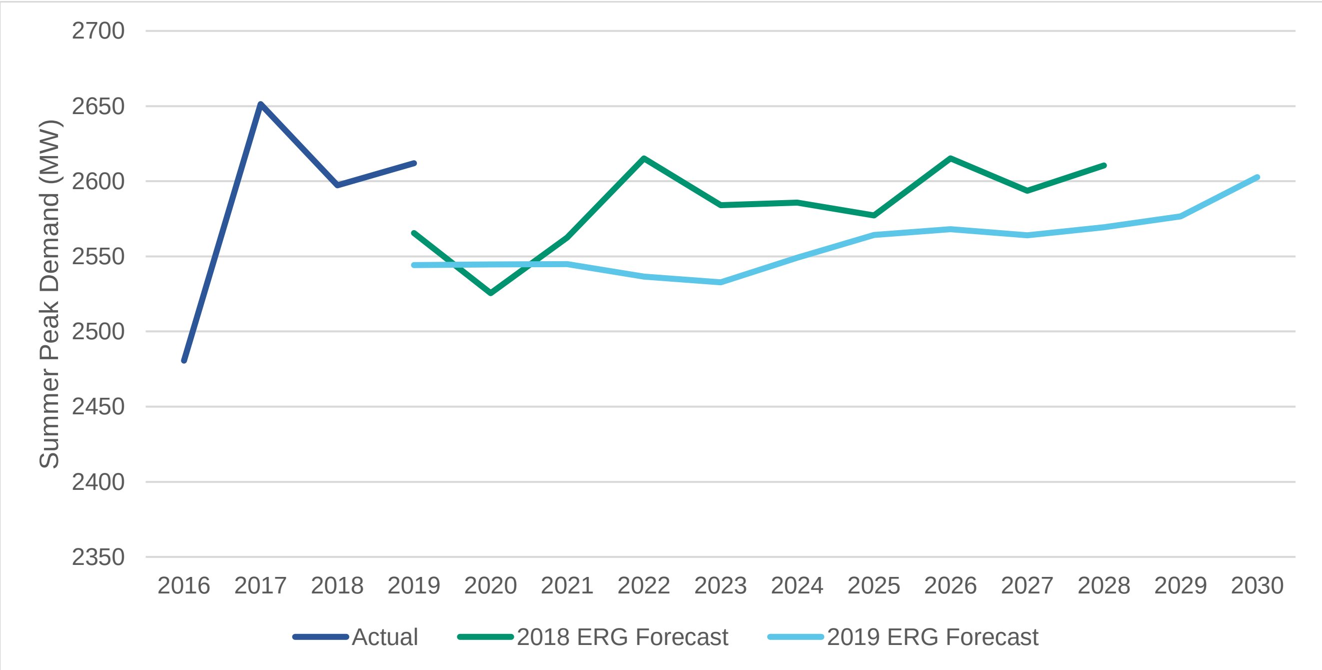
A comparison of the system peak demand forecasts, and the underlying model assumptions and inputs from 2018 to 2019 forecasts, are provided in Table 8.

Table 8 System peak demand forecasts: 2018 and 2019 comparison

Measure	Unit	2018 Forecast	2019 Forecast
2020 Peak Demand (50 PoE Base Case)	MW	2,525.50	2,544.54
2025 Peak Demand (50 PoE Base Case)	MW	2,577.19	2,564.24
2020-25 Average Annual Growth Rate (50 PoE Base Case)	%	0.17%	0.04%
2020-25 Average Annual GSP Growth Rate	%	2.75%	2.24%
2020-25 Average Annual Population Growth Rate	%	0.69%	0.92%

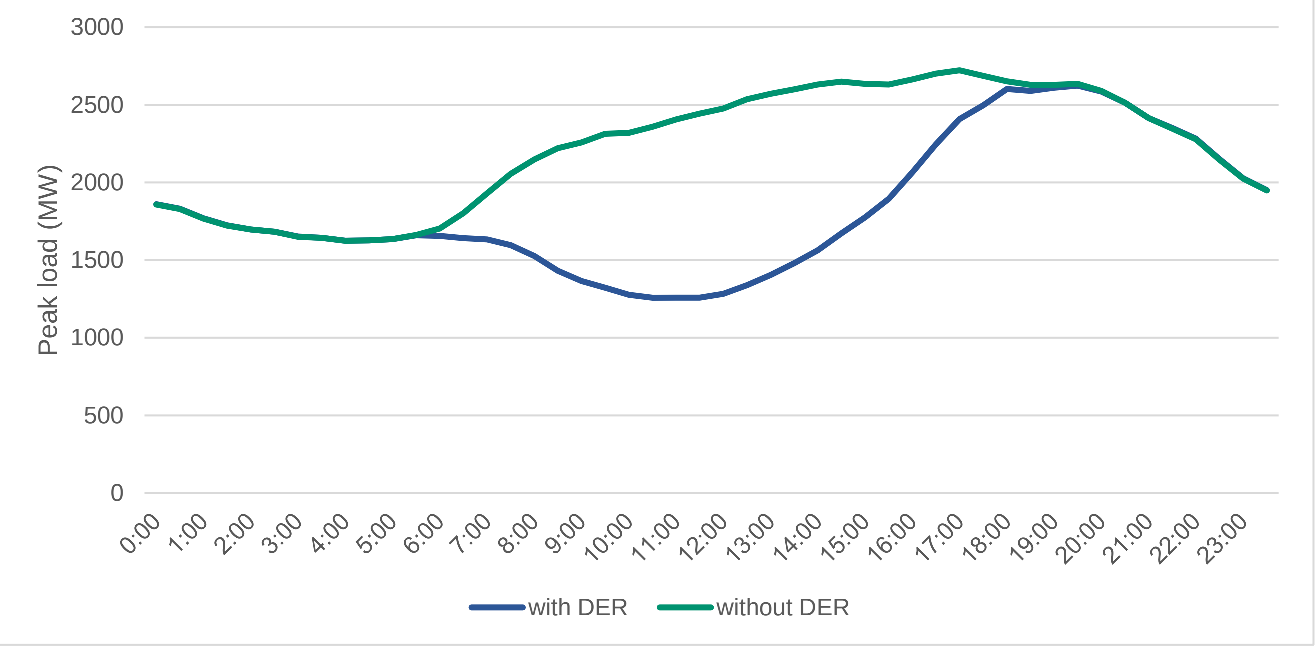
A comparison of the 10-year system peak demand forecasts from 2018 and 2019 is provided in Figure 6. It shows the slightly higher actual peak demand for 2019, with lower peak demand outcomes for each year during the 2020-25 regulatory control period.

Figure 6: System peak demand forecast (MW)



The expected average peak demand for the 2020-25 regulatory control period incorporates the expected impact of Distributed Energy Resources (DER) such as solar and batteries. In 2025, solar exports to the grid will result in a system peak demand that is both lower and later in the day than it otherwise would have been. Figure 7 shows the forecasted half hourly interval demand data for a peak demand day in 2025. As shown in Figure 7 the peak is marginally lower and shifts to later in the day when DER is included.

Figure 7: Peak day network load profile for 2025 with and without DER



5.1 Demand forecast method

Ergon Energy engaged an external consultant, ACIL Allen, to review both the model methodology and the associated forecasts. A suite of recommendations was made, including consideration of the use of regional drivers in our network, and removal of the air-conditioning from the model structure. The ACIL Allen report has been provided as an attachment to this Revised Regulatory Proposal.

Most of ACIL Allen's recommendations were accepted and integrated into the system and regional peak demand forecasting models, from which a revised 2019 peak demand forecast was derived using data up to 31 March 2019. The revised forecasting methodology resulted in the 2019 Forecast Assumptions detailed in Table 9.

Table 9: 2019 Forecast Assumptions

Parameters	Description
Network Load	Five regional peak demand loads (Far North, North, Central, Mackay, Wide Bay) based on summation of connection points.
GSP	Gross State Product (chain volume) - National Institute of Economic and industry Research base case (changed from NIEIR low case used in 2018)
Days	Variable for Weekends and Days of week
Temperature	Weather (maximum and minimum temperatures)

There was little change in Ergon Energy's system peak demand forecast, though there was some change to the areas that would observe the highest growth rates.

5.2 Customer number forecast

In this Revised Regulatory Proposal, we have updated our forecast customer numbers to align with those provided by the Queensland Competition Authority. For 2025, this reduced our forecast customer numbers to 774,870 (819,996 previously) with a corresponding adjustment to customer growth across the regulatory control period.

5.3 Supporting documentation

The following document supporting this chapter:

Name	Ref	File Name
ACIL Forecasting Report	5.001	EGX ERG 5.001 ACIL Allen System Demand Forecast Review ACIL Allen DEC19 PUBLIC

6. Capital expenditure

In this Revised Regulatory Proposal, we are proposing a net capex of $2,817 million (Real $2020), reflecting a $93 million increase from our Regulatory Proposal. This compares with the AER's Draft Decision of $2,151 million.

In its Draft Decision the AER made it clear that we failed to provide sufficient justification for some of the capex included in our Regulatory Proposal. We appreciate this feedback and note the constructive engagement we have had with the AER and the support we have received from other stakeholders to address this issue.

We recognise the AER's concerns surrounding the reconciliation of our recast CA RIN data to previously submitted CA RIN data for 2014-15 and 2015-16. Our ability to reconcile the pre-merger data is hampered by system and resources changes resulting from the merger and the assumptions used. We note that this reconciliation is to provide information for AER's capex assessment and is one of many other tools that the AER has at its disposal.

In the Draft Decision, the AER stated that it will have regard to all of our revised proposal information. In preparing this Revised Regulatory Proposal, we have engaged external expertise to assist us with the risk assessment quantification and have applied this approach in our revised business cases to demonstrate and justify the investment needs. We therefore encourage that the AER places a higher weight on the prudence of our capex program through our risk quantification assessments efforts.

To provide AER with some comfort on the integrity of our data, we are working to provide the reconciliation based on direct repex costs only which are reported in the historic CA RIN. The reconciliation work will include quantified differences and explanations for these differences.

6.1 What we have heard from the AER and our customers

Responses from customers generally support our Regulatory Proposal themes of safety, affordability, security and sustainability with affordability appearing to be the primary concern for most customers.

We note the concerns raised by the Consumer Challenge Panel (CCP14) and Energy Consumers Australia (ECA) regarding the sustainability of our forecast savings, lower WACC, incentive schemes and the prudency and efficiency of our investments. We also note the safety issues raised by the Queensland Electrical Safety Office; particularly in relation to neutral failure and conductor clearance matters. Table 10 summarises the issues raised by the AER and how we have responded.

Table 10 Summary of feedback on capex

Issues	What we heard	How we responded
Total capex	• Inconsistent application of investment governance and management framework, inadequate risk-based cost-benefits analysis of programs and projects.	• A standard template and methodology to include assessment of risks, counterfactual arguments and options analysis is now used for all business cases.
Augex	• Lack of options analysis and compliance to Safety Net Target obligations not demonstrated. • Lack of cost-benefit analysis in support of smart network (power quality monitoring and intelligent grid) enablement programs.	• We have provided clarification on how the Safety Net Target obligation is to be applied. • We have also updated our business cases to include risks and option assessments and cost-benefit analysis.

Connections	• Our connections and capital contributions forecasts are reasonable, and the AER has included the forecast amounts in their total capex.	• We accept the AER's Draft Decision on our connection capex.
Repex	• Modelled replacement capital expenditure (repex) is significantly higher that predictive modelling threshold or historical expenditure. Lack of risk-based cost-benefit analysis. LV safety program not justified on economic or legislative grounds.	• We have engaged external expertise to assist us with the risk assessment quantification. We have applied this approach in our business cases to demonstrate and justify the investment needs.
ICT	• High costs of "minor application upgrades" along with inclusion of contingency costs and deliverability concerns with the planned major ICT projects. Contribution of the estimated ICT program benefits to Energy Queensland's productivity targets was unclear.	• We accept the AER's substituted ICT capex with a minor adjustment. • We had included a negative step change to our opex to account for the quantified benefits from the implementation of the ICT program.
Property	• Expectation of further justification of the planned Major Projects and one of the Other Property Program investments	• We have engaged external expertise to redevelop the business case analyses for two planned Major Project investments (including one joint project with Energex) and one Other Property Program investment on Property Security. • These business cases now include further analysis of needs, options and economic analyses and change impact assessments. • We had included a negative step change to our opex to account for the quantified benefits from the implementation of our property program
Other non network - Fleet	• Some fleet service life and unit rate assumptions did not reflect efficient costs or were lacking in evidence	• We have redeveloped our Fleet models and adopted a consistent, rigorous approach to application of forecast age or kilometre-based service lives. A detailed review of unit rates has been undertaken from various sources.
Other non-network – Tools and Equipment	• The AER assessed that our forecast of tools and equipment were higher than expectations.	• We accept the AER's Draft Decision on our Other Non-Network Tools & Equipment capex

Capitalised Overheads	• The AER corrected an error in our modelling and flat-lined our capitalised overheads.	• We have updated our 2018-19 base year overheads, applied our new CAM, and adopted the AER's methodology for Energex in our capitalised overheads forecasts.

6.2 Our capital expenditure

In our Regulatory Proposal, submitted on 31 January 2019, we forecast a net capex requirement of $2,724 million (Real $2019-20). This capex forecast was approximately 14% above our estimated capex in the current regulatory period (or 11% below the AER allowance).[1]

Our Distribution Authority prescribes that we must plan and develop our supply network in accordance with good electricity industry practice to meet the minimum service standards (MSS) and Safety Net Target. It also requires that we address the reliability of the worst performing feeders on our network. Further the Queensland Electrical Safety Act 2002 includes an obligation that we must ensure that our works are electrically safe and are operated in a way that is electrically safe.

Our repex program is primarily driven by the need to maintain or improve safety outcomes for our communities, customers and employees as required under our Distribution Authority and other relevant legislative instruments. Some replacement capex is driven by the economics of high costs of maintaining assets that are ageing and in poor asset condition.

Our augmentation capex (augex) forecast has been developed to comply with our obligations as a distribution network service provider and to continue to deliver secure and reliable supply in the evolving electricity market. Our augmentation capex includes traditional network upgrade solutions to cater for demand growth as well as expenditures required to modernise the network to operate a more complex grid. The proliferation of DER connected to our network have changed the characteristics of our low voltage (LV) network from a simple one-way flow to the more complex bi-directional flow. Integration of DER into our distribution network and managing bi-directional flow requires innovative technology investments to enable a smart grid that will improve asset utilisation and maintain our ability to provide a secure and reliable energy supply.

We provide customer connections to our distribution network under our connection capex which is primarily driven by customer growth within our area of supply. All connections are performed in accordance with our Connection Policy and Capital Contributions framework.

Our non-network capex forecast relates to the provision of Information and Communications Technology (ICT), Property, Fleet and Equipment in support of the activities of our business.

6.3 Overview of our revised capital expenditure

We have considered the AER's concerns on the lack of options analysis and cost-benefit justification in some of the business cases presented in our January 2019 Regulatory Proposal submission.

[1] Page 30 , AER's Draft Decision Ergon Energy Distribution 2020 to 2025 Overview

In this Revised Regulatory Proposal, we have provided expanded business cases which include counterfactual arguments, options and cost-benefit analyses, quantified risk assessments and details of how the proposed capex forecasts meet the capital expenditure objectives and criteria as required under the NER.

6.3.1 Approach to our Revised Capital Expenditure

In response to the AER's Draft Decision, our approach in this Revised Regulatory Proposal is to review our capital expenditure forecast and categorise them as accept, modify or justify as detailed in Chapter 2.

6.3.2 Program-wide adjustments

In preparing this Revised Regulatory Proposal, we have considered several factors that influence all aspects of our capital expenditure program which have changed since the time of our Regulatory Proposal submission including:

- **Safety / condition changes assessment**

  We have conducted several aerial based inspection programs on our assets in recent years. Since the lodgement of our Regulatory Proposal, we have received further information from the latest aerial program. This inspection program shows significant numbers of Clearance to Structure (CTS) and Clearance to Ground (CTG) defects that necessitate immediate attention. This is described further in Attachment 6.018 Business Case CTG/CTS.
- **Quantified Risk Assessments**

  We have engaged external expertise to assist us with risk assessment quantification. This risk quantification work has been modelled on the AER Industry Practice Application Note for Asset Replacement Planning[2]. This work is detailed in Attachment 6.04 "Risk Methodology Summary".
- **Capex / Opex Trade-offs**

  All resubmitted business cases now include clearly quantified benefits or savings. Quantified benefits from our ICT and property programs had been included in our internal opex forecasts as negative step changes and are also incorporated into our capitalised overheads.
- **Labour cost escalators and Unit rates**

  We have updated our cost escalators and unit rates based on latest available information. We have retained the historically accepted approach of averaging our BIS Oxford Economics and the AER's Deloitte Access Economics for our labour escalators.

6.3.3 Summary of changes of revised capex forecast

Our revised capex forecast largely accepts the AER's Draft Decision. We have provided additional justification for important augex to meet customer demand and establish a smart network to integrate solar and batteries. We have modified the scope of some projects or programs based on the AER's feedback or where we have identified new information since the submission of our Regulatory Proposal in January 2019. The remainder of our capex forecast is focussed on re-justifying the needs and costs presented with our Regulatory Proposal with additional evidence.

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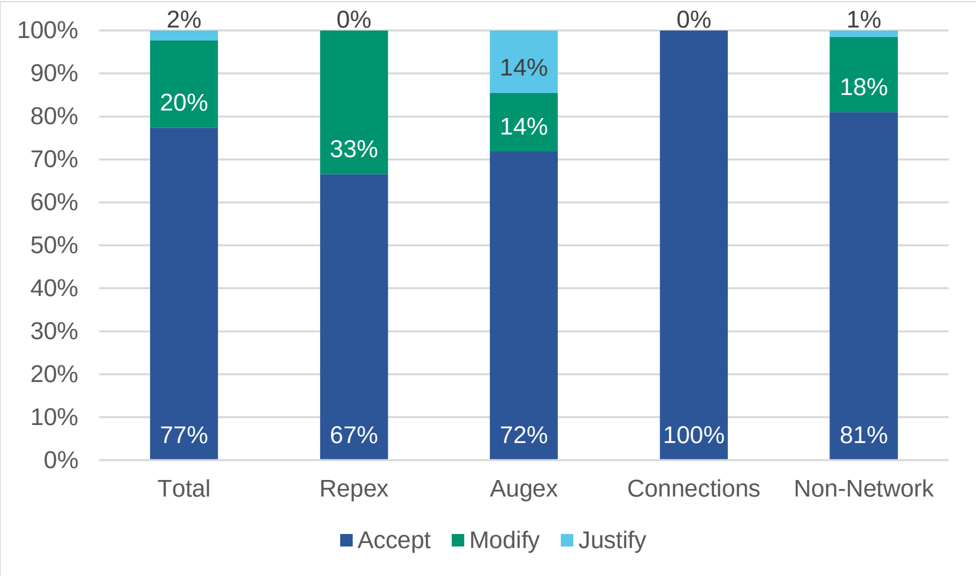
[2] AER Industry practice application note for asset replacement planning Jan 2019

Figure 8 shows the proportion of the AER's Draft Decision capex amount that we have accepted, modified or justified in this Revised Regulatory Proposal.

Figure 8: Revised Forecast Capex



Totals may not add due to rounding.

6.4 Revised capital expenditure forecast

Table 11 sets out our revised forecast capex by capex driver over the 2020-25 regulatory control period.

Table 11: Revised capex forecast by capex driver

$M Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Replacement	234.79	239.97	264.40	272.94	277.47	**1,289.57**
Augmentation	55.28	55.29	55.10	41.38	32.46	**239.50**
Connections (including capital contributions)	79.13	76.80	72.97	73.34	74.46	**376.71**
ICT	34.20	33.97	33.33	29.56	33.34	**164.40**
Property	29.33	32.79	22.30	11.40	8.02	**103.84**
Fleet	24.04	31.48	29.81	18.98	24.01	**128.33**
Other Non-Network	4.38	4.41	4.45	4.43	4.44	**22.12**
Overheads	133.23	135.16	136.84	137.62	139.31	**682.16**
Total (Gross capex)	**594.39**	**609.87**	**619.20**	**589.66**	**593.51**	**3,006.63**
Capital Contributions	38.06	35.29	31.84	31.87	31.90	**168.96**
Asset Disposals	3.99	3.99	3.99	4.90	3.99	**20.87**
Total (Net capex)	**552.34**	**570.59**	**583.38**	**552.89**	**557.62**	**2,816.80**

Figure 9 shows the forecast capex by category for the 2020-25 regulatory control period.

Figure 9: Forecast capex categories

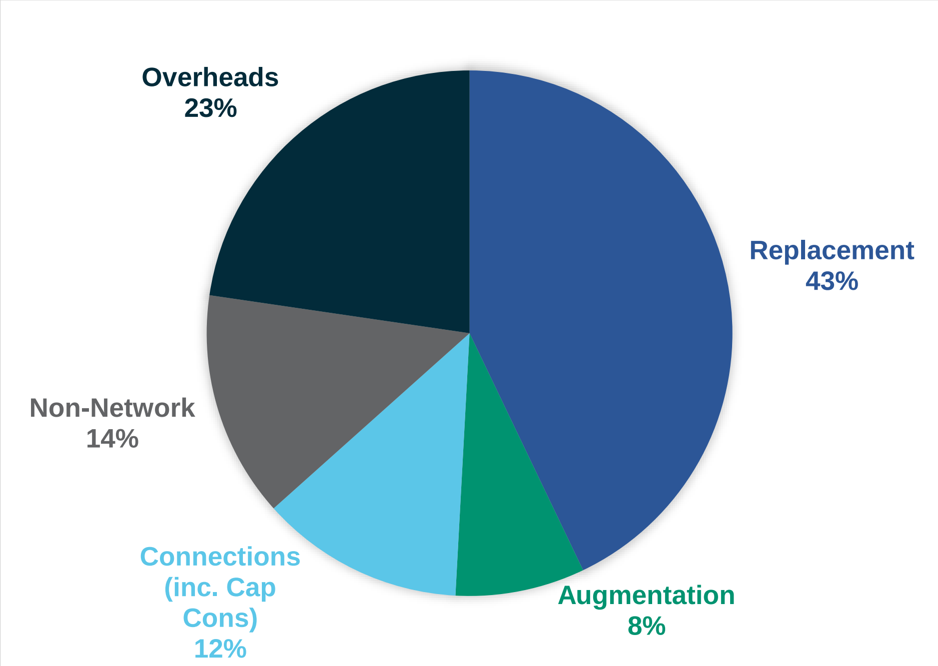


Table 12 provides a summary of our revised capex forecast compared to the capex forecast in our initial Regulatory Proposal and the substituted forecast as set out in the AER's Draft Decision.

Table 12: Comparisons of Capex Forecast Summary

$M Real $2020	Regulatory Proposal	AER Draft Decision	Revised Regulatory Proposal				
			Forecast	Difference from RP		Difference from DD	
					%		%
Repex	1,094.41	834.53	1,289.57	195.16	*17.83%*	455.04	*54.53%*
Augex	248.51	169.31	239.50	-9.01	*-3.63%*	70.19	*41.46%*
Gross connections	375.91	373.21	376.71	0.80	*0.21%*	3.51	*0.94%*
ICT	210.12	158.44	164.40	-45.72	*-21.76%*	5.95	*3.76%*
Property	128.55	56.09	103.84	-24.71	*-19.22%*	47.75	*85.14%*
Fleet	135.76	114.56	128.33	-7.43	*-5.47%*	13.78	*12.03%*
Other non-network	24.90	22.24	22.12	-2.79	*-11.18%*	-0.12	*-0.55%*
Overheads	686.52	610.64	682.16	-4.37	*-0.64%*	71.51	*11.71%*
Gross capex	**2,904.70**	**2,339.02**	**3,006.63**	**101.93**	***3.51%***	**667.61**	***28.54%***
less capcons	169.87	168.96	168.96	-0.91	*-0.54%*	-	*0.00%*
less disposals	10.59	19.15	20.87	10.28	*97.12%*	1.72	*8.98%*
Net capex	**2,724.24**	**2,150.91**	**2,816.80**	**92.56**	***3.40%***	**665.90**	***30.96%***

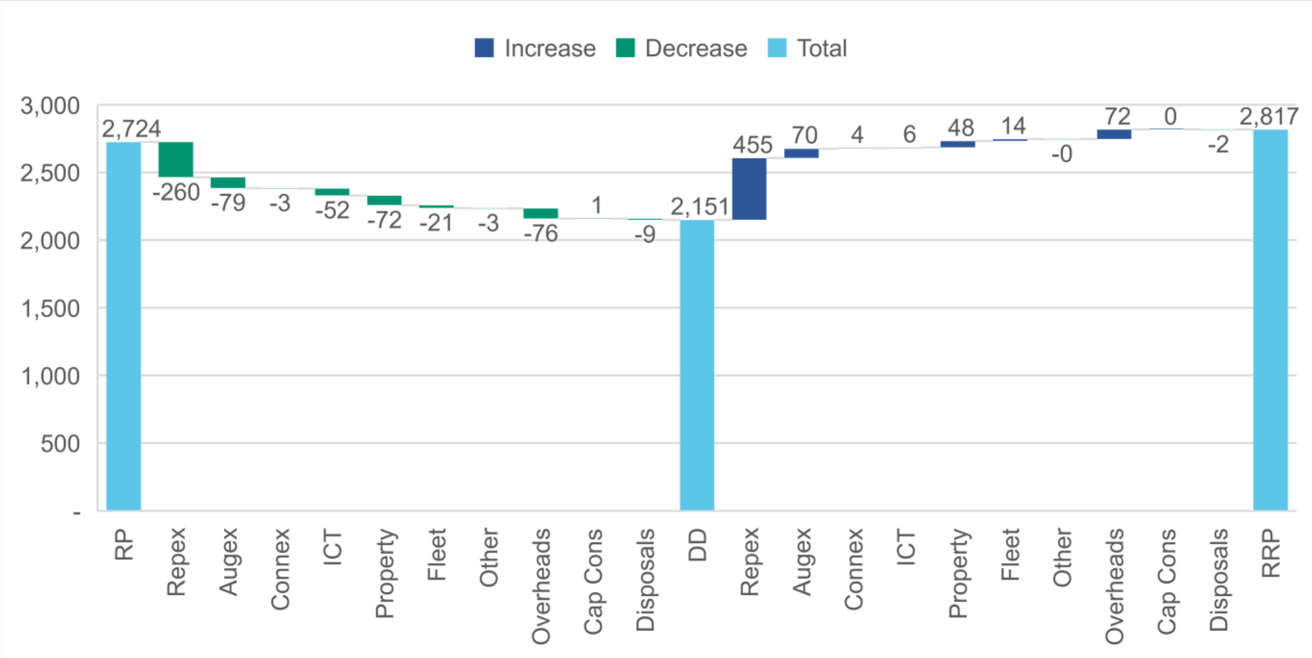
Totals may not add due to rounding.

In summary, our revised net capex in the 2020-25 regulatory control period will be:

- 3.4% (or $93 million) above our forecast capex in our Regulatory Proposal
- 31% (or $666 million) above the AER's allowance in the Draft Decision

Figure 10 shows our revised capex forecasts compared to the initial forecast capex and the AER's Draft Decision.

Figure 10: 2020-25 revised net capex forecast compared to AER's Draft Decision



Details of our revised capex are presented in the remaining sections of this chapter.

6.5 Revised replacement capex (repex)

Our repex is predominantly targeted at managing our network to deliver our safety commitment to our communities, customers and employees. Our investment plans include the deployment of new technologies that will help to improve safety and performance whilst managing affordability. Our customers recognised the value of investing in network technologies that will provide enhanced customer safety and deliver benefits to the wider community. The forecast projects and programs in this Revised Regulatory Proposal are required to mitigate safety risks to our communities, customers and employees.

The Draft Decision did not include any allowance for our LV network safety program which is critical to our safety initiatives. We have reviewed the scope of this program and resubmitted the business case in our Revised Regulatory Proposal for the AER's reconsideration. The updated business case includes details of options and risks analyses and quantified benefits associated with the program.

In response to the AER's feedback we have undertaken significant effort in risk quantification as part of the development of this Revised Regulatory Proposal. This work is detailed in Attachment 6.004 "Risk Methodology Summary". This risk quantification work has been modelled on the AER *Industry Practice Application Note for Asset Replacement Planning*.

Attachment 6.028 “Repex Capex Summary” sets out an overview and details of our proposed replacement capex for this Revised Regulatory Proposal.

Our revised repex forecast for the 2020-25 regulatory control period is set out in Table 13.

Table 13: Revised Replacement capex - Repex ($M 2019-20)

$M Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Regulatory Proposal	200.13	199.65	221.34	234.16	239.13	**1,094.41**
AER Draft Decision	151.36	158.66	166.28	174.63	183.61	**834.53**
Revised Regulatory Proposal	234.79	239.97	264.40	272.94	277.47	**1,289.57**

Note: Draft Decision numbers are from the AER’s capex model and PTRM. Variation of the Draft Decision numbers from Attachment 5 of the Draft Decision is due to allocation of modelling adjustment costs to all capex category.

6.6 Augmentation capex (augex)

Historically, augmentation capex (augex) was driven by strong demand growth (primarily air-conditioning uptake) and economic development in South-East Queensland. While demand growth has slowed in recent years, it remains material. There are pockets of our network where the growth in demand is high and reaching the capacity of relevant network assets. Network augmentation is required to comply with our obligation to the safety net targets prescribed in our Distribution Authority.

We have resubmitted our smart network business cases, as these innovative technology investments are required to maintain our ability to provide a secure and reliable energy supply and comply with our obligations. The electricity industry is rapidly changing and with the increasing penetration of DER, our network is now required to accommodate a growing number of two-way flows on our LV feeders. Voltage fluctuations as a result of excess solar generation and the associated drop when cloud cover impacts generation are caused by the high penetration of roof-top solar on our network. Managing voltage and the other variabilities and uncertainties associated with DER generation is increasingly challenging from a technical perspective. Successfully integrating high levels of DER requires an increasing level of visibility, predictability, and control of these resources. Investments in an upgrade to a smart network will facilitate our ability to dynamically manage our network and increase the hosting capacity which will result in better utilisation of the network.

Attachment 6.029 “Augex Capex Summary Document” sets out an overview and details of our proposed augmentation capex for this Revised Regulatory Proposal. Our revised augex for the 2020-25 regulatory control period is set out in Table 14.

6.7 Connections capex and customer contributions

We accept the AER’s Draft Decision on the forecast for connections capex and customer contribution.

Adjusting for the latest inflation rates and relevant escalations, our revised connections expenditure for the 2020-25 regulatory control period is set out in Table 14.

Table 14: **Revised Connection capex- Connex ($M 2019-20)**

$M Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Regulatory Proposal	79.33	76.75	72.77	73.02	74.04	**375.91**
AER Draft Decision	78.97	76.39	72.28	72.37	73.20	**373.21**
Revised Regulatory Proposal	79.13	76.80	72.97	73.34	74.46	**376.71**

Note: Draft Decision numbers are from the AER's capex model and PTRM. Variation of the Draft Decision numbers from Attachment 5 of the Draft Decision and the Regulatory Proposal is due to allocation of modelling adjustment costs to all capex category.

6.8 Information communication technology (ICT) capex

We accept the AER's Draft Decision on the forecast of our ICT capex with a minor proposed adjustment in the calculation for "Recurrent ICT Capex - Minor Upgrades and Updates". We have taken on board AER and stakeholder feedback regarding the cost estimates and deliverability risks associated with the "Non-Recurrent ICT Capex Program" and accept the AER's substitute position. Ergon Energy will continue to manage program delivery within the reduced forecast, maximising delivery efficiency with priority on risk mitigation, sustainability, security and productivity enablement.

The quantified benefits identified in the business cases submitted were to be incorporated as negative opex step changes, but now form part of our internal opex forecast only.

Attachment 6.008 ICT Capex Summary Document sets out an overview and details of our proposed ICT capex for this Revised Regulatory Proposal.

Our revised ICT capex for the 2020-25 regulatory control period is set out in Table 15.

Table 15: **Revised ICT capex ($M 2019-20)**

$M Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Regulatory Proposal	44.35	43.93	42.77	37.79	41.28	**210.12**
AER Draft Decision	33.43	33.03	32.60	27.68	31.70	**158.44**
Revised Regulatory Proposal	34.20	33.97	33.33	29.56	33.34	**164.40**

Note: Draft Decision numbers are from the AER's capex model and PTRM. Variation of the Draft Decision numbers from Attachment 5 of the Draft Decision is due to smearing of allocation adjustment costs to all capex category.

6.9 Revised property capex

Our property strategy is to deliver a safe and efficient, fit-for-purpose and customer-centric property portfolio that will support Queensland communities and customers by ensuring we have facilities in the right locations to enable the operation of a safe and efficient network.

In this Revised Regulatory Proposal, we have provided enhanced business cases for our planned Major Projects to justify our property expenditure. These business cases include more thorough analyses of "counterfactual" base case scenarios, alternative options analyses, sensitivity analyses, independent condition assessments, quantity surveyor cost estimates, risk and benefit analyses.

The quantified benefits identified in the business cases submitted were to be incorporated as negative opex step changes, but now form part of our internal opex forecast only.

Attachment 6.012 “Property Capex Summary Document” sets out an overview and details of our proposed capex for property this Revised Regulatory Proposal.

Our revised proposed property capex for the 2020-25 regulatory control period is set out in Table 16.

Table 16: Revised Property capex ($M 2019-20)

$M Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Regulatory Proposal	26.81	32.37	33.01	20.19	16.17	**128.55**
AER Draft Decision	15.93	12.96	7.78	11.40	8.02	**56.09**
Revised Regulatory Proposal	29.33	32.79	22.30	11.40	8.02	**103.84**

Note: Draft Decision numbers are from the AER’s capex model and PTRM. Variation of the Draft Decision numbers from Attachment 5 of the Draft Decision is due to allocation of modelling adjustment costs to all capex category.

6.10 Revised fleet capex

Investing in fleet assets enables us to deliver distribution services in line with community and customer expectations to support the efficient delivery of our network program of work. We continue to seek efficiencies through fleet standardisation and improved optimisation of our fleet portfolio. The objectives of our Fleet and Equipment Asset Management Strategies continue to be to identify fleet and equipment assets which meet business requirements based on the principle of fit-for-purpose design considering safety, industry standards, business priorities and cost efficiency.

In this Revised Regulatory Proposal, we have revised our fleet forecasts using a standardised approach and model. The revised modelling adopts a consistent, rigorous approach to the application of forecast age or kilometre-based service life replacements based on each fleet asset’s in-service date. We have also reviewed the unit rates of our fleet portfolio based on historical general ledger transactions, invoices or contracts as applicable.

Attachment 6.011 “Fleet Capex Summary Document” sets out an overview and details of our revised capex for fleet in this Revised Regulatory Proposal. Our revised fleet capex for the 2020-25 regulatory control period is set out in Table 17.

Table 17: Revised Fleet capex

$M Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Regulatory Proposal	27.36	26.97	27.20	26.27	27.96	**135.76**
AER Draft Decision	21.13	27.87	25.59	16.35	23.62	**114.56**
Revised Regulatory Proposal	24.04	31.48	29.81	18.98	24.01	**128.33**

Note: Draft Decision numbers are from the AER’s capex model and PTRM. Variation of the Draft Decision numbers from Attachment 5 of the Draft Decision is due to allocation of modelling adjustment costs to all capex category.

6.11 Revised tools and equipment capex

We accept the AER's Draft Decision on the forecast for tools and equipment capex and are not submitting any revised business cases.

Adjusting for the latest inflation rates and relevant escalations, our revised tools and equipment expenditure for the 2020-25 regulatory control period is set out in Table 18.

Table 18: Revised Tools and Equipment capex ($M 2019-20)

$M Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Regulatory Proposal	4.93	4.97	5.01	4.99	5.00	**24.90**
AER Draft Decision	4.40	4.44	4.47	4.46	4.47	**22.24**
Revised Regulatory Proposal	4.38	4.41	4.45	4.43	4.44	**22.12**

Note: Draft Decision numbers are from the AER's capex model and PTRM. Variation of the Draft Decision numbers from Attachment 5 of the Draft Decision is due to allocation of modelling adjustment costs to all capex category.

6.12 Revised capitalised overheads

We have adopted an approach that is consistent with the methodology adopted for Energex and accepted by the AER in its Draft Decision for Energex.

In summary, we have:

- Updated our 2018-19 overheads for actuals per our annual 2018-19 Regulatory Information Notice (RIN)
- Applied our 2020-25 Cost Allocation Method (CAM) to derive the 2018-19 base year capitalised overheads
- Quantified our actual direct capex and associated overheads for the 2015-16 to 2018-19 capex program to determine the proportion of capitalised overheads to our total capex cost (this constituted 52.61%)
- Adopted the AER's Draft Decision of 25% as the variable component of capitalised overheads
- The resulting 13.15% reduction of variable capitalised overheads is applied to each year to determine the forecast capitalised overheads for the 2020-25 regulatory control period.

Adjusting for the latest inflation rates and relevant escalations, our capitalised overheads expenditure for the 2020-25 regulatory control period is set out in Table 19.

Table 19: Revised Capitalised Overheads capex ($M 2019-20)

$M Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Regulatory Proposal	130.36	132.38	135.86	140.74	147.17	**686.52**
AER Draft Decision	122.13	122.13	122.13	122.13	122.13	**610.64**
Revised Regulatory Proposal	133.23	135.16	136.84	137.62	139.31	**682.16**

Note: Draft Decision numbers are from the AER's capex model and PTRM. Variation of the Draft Decision numbers from Attachment 5 of the Draft Decision is due to allocation of modelling adjustment costs to all capex category.

6.13 Supporting documentation

The following documents supporting this chapter accompany our Revised Regulatory Proposal:

Name	Ref	File name
Business Case LV Network Safety	6.001	EGX ERG 6.001 Business Case LV Network Safety DEC19 PUBLIC
Business Case Secure Data Zone	6.002	EGX ERG 6.002 Business Case Secure Data Zone DEC19 PUBLIC
Risk Quantification Methodology	6.003	EGX ERG 6.003 Risk Quantification Methodology Aurecon DEC19 PUBLIC
Business Case Intelligent Grid Enablement	6.004	EGX ERG 6.004 Business Case Intelligent Grid Enablement DEC19 PUBLIC
ICT Capex Summary Document	6.005	EGX ERG 6.005 ICT Capex Summary Document DEC19 PUBLIC
Fleet, Tools and Equipment Capex Summary Document	6.006	EGX ERG 6.006 Fleet, Tools and Equipment Capex Summary Document DEC19 PUBLIC
Property Capex Summary Document	6.007	EGX ERG 6.007 Property Capex Summary Document DEC19 PUBLIC
Business Case Rockhampton OTFH	6.008	EGX ERG 6.008 Business Case Rockhampton OTFH DEC19 PUBLIC
Business Case DC Services Duplication	6.009	EGX ERG 6.009 Business Case DC Services Duplication DEC19 PUBLIC
Smart Network Overview	6.010	EGX ERG 6.01 Smart Network Overview DEC19 PUBLIC
Crane Borer Assessment	6.011	EGX ERG 6.011 Crane Borer Assessment DEC19 PUBLIC
Business Case Protection Scheme DER	6.012	ERG 6.012 Business Case Protection Scheme DER DEC19 PUBLIC
Business Case Protection Scheme SEF	6.013	ERG 6.013 Business Case Protection Scheme SEF DEC19 PUBLIC
Business Case Property Security	6.014	ERG 6.014 Business Case Property Security DEC19 PUBLIC
Business Case Childers to Gayndah	6.015	ERG 6.015 Business Case Childers to Gayndah DEC19 PUBLIC
Business Case Circuit Breakers and Reclosers	6.016	ERG 6.016 Business Case Circuit Breakers and Reclosers DEC19 PUBLIC
Business Case Communication Site Infrastructure	6.017	ERG 6.017 Business Case Communication Site Infrastructure DEC19 PUBLIC
Business Case Communications Power Systems	6.018	ERG 6.018 Business Case Communications Power Systems DEC19 PUBLIC

Name	Ref	File name
Business Case CTG CTS	6.019	ERG 6.019 Business Case CTG CTS DEC19 PUBLIC
Business Case Field Mobile Voice Comms	6.020	ERG 6.02 Business Case Field Mobile Voice Comms DEC19 PUBLIC
Business Case Fixed Voice Communications	6.021	ERG 6.021 Business Case Fixed Voice Communications DEC19 PUBLIC
Business Case Instrument Transformers	6.022	ERG 6.022 Z943Business Case Instrument Transformers DEC19 PUBLIC
Business Case Life Extension of Legacy Telecommunications Data Comms	6.023	ERG 6.023 Business Case Life Extension of Legacy Telecommunications Data Comms DEC19 PUBLIC
Business Case Operational Technology Environment	6.024	ERG 6.024 Business Case Operational Technology Environment DEC19 PUBLIC
Business Case Physical Linear Media	6.025	ERG 6.025 Business Case Physical Linear Media DEC19 PUBLIC
Business Case Pole Top Structures Replacement	6.026	ERG 6.026 Business Case Pole Top Structures Replacement DEC19 PUBLIC
Business Case Poles and Towers	6.027	ERG 6.027 Business Case Poles and Towers DEC19 PUBLIC
Business CaseLow Voltage Service Lines	6.028	ERG 6.028 Business CaseLow Voltage Service Lines DEC19 PUBLIC
Repex Capex Summary Document	6.029	ERG 6.029 Repex Capex Summary Document DEC19 PUBLIC
Augex Capex Summary Document	6.030	ERG 6.03 Augex Capex Summary Document DEC19 PUBLIC
Business Case Backup Reach Program	6.031	ERG 6.031 Business Case Backup Reach Program DEC19 PUBLIC
Business Case Blackwater Substation Refurbishment	6.032	ERG 6.032 Business Case Blackwater Substation Refurbishment DEC19 PUBLIC
Business Case Pittsworth, Broxburn & Yarranlea	6.033	ERG 6.033 Business Case Pittsworth, Broxburn & Yarranlea DEC19 PUBLIC
Business Case Burnett Heads 66kV Line Augmentation	6.034	ERG 6.034 Business Case Burnett Heads 66kV Line Augmentation DEC19 PUBLIC
Business Case Cloncurry Supply Reinforcement	6.035	ERG 6.035 Business Case Cloncurry Supply Reinforcement DEC19 PUBLIC
Business Case Network Capacity and Coverage	6.036	ERG 6.036 Business Case Network Capacity and Coverage DEC19 PUBLIC
Business Case Power Quality	6.037	ERG 6.037 Business Case Power Quality DEC19 PUBLIC

Name	Ref	File name
Business Case Townsville Training Facility	6.038	ERG 6.038 Business Case Townsville Training Facility DEC19 PUBLIC
Business Case Maryborough Consolidation	6.039	ERG 6.039 Business Case Maryborough Consolidation DEC19 PUBLIC
Business Case Obsolete Data Telecommunications	6.04	ERG 6.042 Business Case Obsolete Data Telecommunications DEC19 PUBLIC
Business Case Substation Transformers	6.041	ERG 6.043 Business Case Substation Transformers DEC19 PUBLIC
Business Case Protection Scheme Comms	6.042	ERG 6.044 Business Case Protection Scheme Comms DEC19 PUBLIC
Forecast Capex Model(s) and Methodology	6.043	ERG 6.045 Forecast Capex Model(s) and Methodology DEC19 PUBLIC
Business Case LV Network Safety	6.044	EGX ERG 6.001 Business Case LV Network Safety DEC19 PUBLIC
Business Case Secure Data Zone	6.045	EGX ERG 6.002 Business Case Secure Data Zone DEC19 PUBLIC

7. Revised operating expenditure

7.1 Our Operating Expenditure

Our proposed SCS operating expenditure (opex) for the 2020-25 regulatory control period is $1,835 million (real $2019-20) including debt raising costs. This is the same amount we submitted in our Regulatory Proposal and that was accepted by the AER in its Draft Decision.

Our opex is associated with managing the network which includes inspections, maintenance, vegetation management and emergency response. It also includes other non-network costs such as customer service call centres, fuel and technical trade training that we need to deliver our distribution services.

We must operate and maintain our network in a manner that meets both:

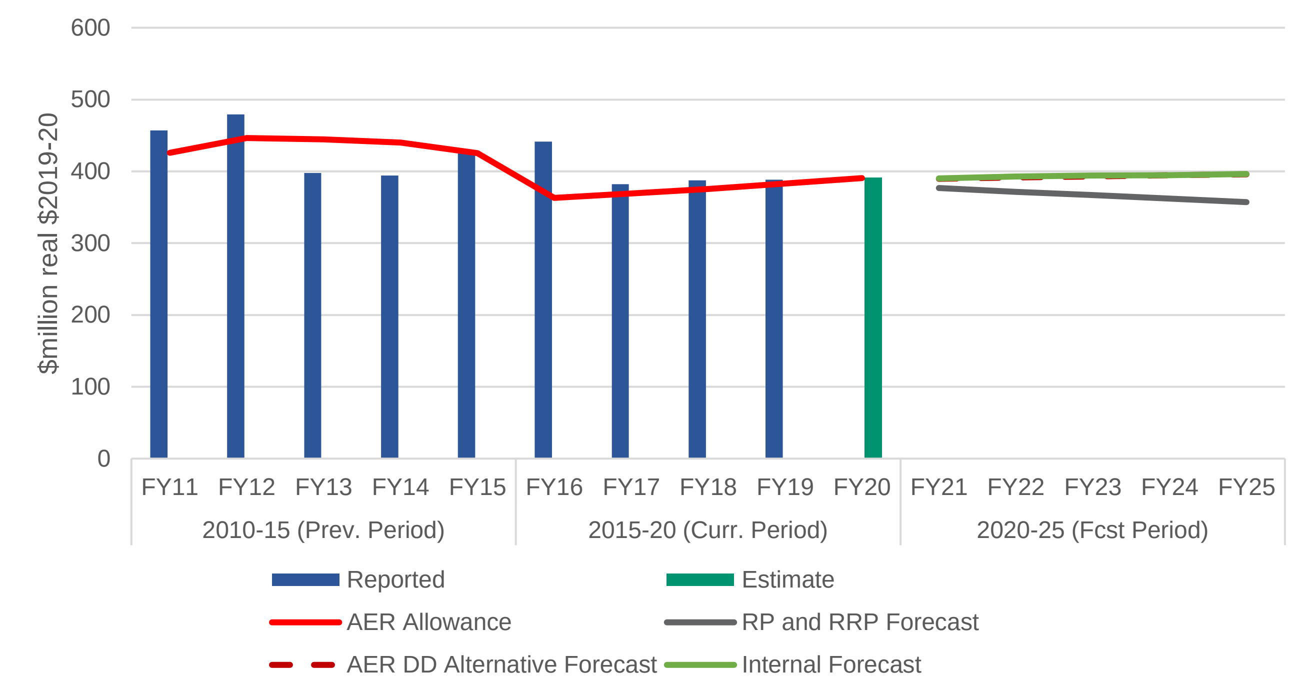
- the service obligations in our Distribution Authority and the Queensland Electricity Distribution Network Code
- our customers' reasonable expectations that we should maintain the safety and reliability of our services and restore power when emergencies and severe weather interrupt them.

To prepare our Revised Regulatory Proposal, we updated our forecast opex using the AER's base-step-trend methodology. Using our actual results for 2018-19 for the base year, accounting for the negative step changes associated with savings from our property and ICT capex programs and using the AER's 0.5% industry-wide productivity saving resulted in an internal forecast that was 7.2% higher than our January Regulatory Proposal.

Recognising this and our commitment to affordable customer outcomes, we have re-submitted the lower opex forecast used in our Regulatory Proposal. This recognises that the AER accepted our January forecast in its Draft Decision, having determined that it was not materially inefficient.

Our actual and forecast opex for each year of the 2010-15, 2015-20 and 2020-25 regulatory control periods are shown in Figure 11. It also shows our higher internal forecast for opex in the 2020-25 regulatory control period for comparison.

Figure 11 Historical and forecast opex (includes debt raising costs)



Our updated internal forecast used the AER method and reflected our actual opex for 2018-19 which was higher than estimated, driven by higher spend on emergency response in that year. This unforeseen higher expenditure involved responding to severe weather events in regional Queensland, including Townsville flooding, Cyclone Owen and the super cell that hit the Fraser coast.

In our engagement, our customers told us they value us restoring power as soon as possible when weather causes outages. Our January Regulatory Proposals committed that we will: "*continue to 'be there after the storm' so that our communities can recover quickly after any disruptive storms or natural disasters*". The 2019 summer season has already delivered the earliest and most severe start to a bushfire season on record, with significant and devastating bushfire activity across the state.

For our internal forecast, we normalised our emergency response expenditure down to a ten-year historical average in our base year. However, we remain exposed to our emergency response expenditure being persistently higher than the historical average. For example, in four of the last five years we've been above that ten-year average.

We validated the efficiency of our actual opex outcomes by testing against the econometric models considered in the AER's 2019 Annual Benchmarking Report. We consider that according to the AER benchmarking criteria our base year continues to be not materially inefficient, after normalising emergency response. This is consistent with the conclusion reached by Frontier Economics in its attached benchmarking study (Frontier Report DEC19, 7.005).

We included in our internal opex forecast the AER's 0.5% industry-wide productivity saving as well as negative step changes to reflect the quantified benefits of our capex investments in ICT and property. These proactive savings total $38.5 million (real $2019-20) over 5 years.

To meet our commitment to drive down the cost of distributing electricity across Queensland with our Revised Regulatory Proposals we are delivering even further savings for customers by not using this updated internal forecast and limiting our revised opex to our January submission amount in line with the AER's Draft Decision.

Delivering our obligations with reduced revenue will be a challenge. We have worked hard to reduce our opex while sustaining the network and are confident in our ability to deliver further cost reductions and savings for our customers.

7.2 What we have heard from the AER and our customers

7.2.1 Customer and stakeholder responses

In addition to their valuable feedback on Our Draft Plans and involvement in our pre and post lodgement engagement, six stakeholders made submissions to the AER on Ergon Energy's opex proposal.[3] Table 20 summarises these responses (as presented in the AER's Draft Decision) and outlines how we responded to each issue for our internal forecast.

Notwithstanding our responses below, we note that our revised opex forecast has been limited to our January submission amount. This responds to the overarching affordability concerns that we have heard from our communities, customers and industry partners.

Table 20 What we heard and how we responded

Issue	What we heard	How we responded
Choice of base year and assessment of efficient base opex	QCOSS stated that Ergon Energy's benchmarking results indicate Energex's base opex may be relatively inefficient and needs to be adjusted for the inclusion of SPARQ opex.[4] The ECA also questioned whether Ergon Energy's performance in the midrange of the AER's opex benchmarks is justified, and whether customers should expect the Energy Queensland networks to achieve deeper efficiencies.[5] The ECA and the consultants, Dynamic Analysis, were not convinced that Energy Queensland's environmental and operating context justified higher costs relatively to its peers.[6] Dynamic Analysis argued it is up to the networks to quantitatively demonstrate how their operating and environmental factors lead to higher costs structures.[7] Dynamic Analysis also noted there is no evidence of what the negative base adjustments specifically relate to, but recognised Energy Queensland's efforts to do the right thing by excluding non-recurrent costs.[8] National Seniors Australia also argued Ergon Energy, as part of Energy Queensland, is not pursuing opportunities with Energex to share costs to reduce operating costs.[9]	We instructed Frontier Economics to update the benchmarking and OEF analysis. It confirmed that Ergon Energy's base year is efficient once emergency response expenditure is normalised. Our updated base year (used in our internal forecast) reflects application of the AER-approved cost allocation method (CAM) that account for a fair and compliant sharing of costs across the merged EQ group.

[3] These included Consumer Challenge Panel (CCP14), the Queensland Council of Social Services (QCOSS), National Seniors Australia, Origin Energy, the Energy Consumers Australia (ECA)—supported by a report from Dynamic Analysis, and the Queensland Government's Electrical Safety Office.

[4] Queensland Council of Social Services, *QLD electricity distribution determinations – Energex and Ergon 2020 to 2025, QCOSS Submission: AER Issues Paper*, May 2019, p. 8.

[5] Energy Consumers Australia, *AER Issues Paper: QLD electricity distribution determinations Energex and Ergon Energy 2020 to 2025 Submission*, June 2019, p. 15.

[6] Energy Consumers Australia, *AER Issues Paper: QLD electricity distribution determinations Energex and Ergon Energy 2020 to 2025 Submission*, June 2019, p.15; Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020-25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 6.

[7] Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020–25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 27.

[8] Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020–25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 32.

[9] National Seniors Australia, *Response to AER Issues Paper: Qld electricity distribution determinations, Energex and Ergon Energy, 2020 to 2025,* May 2019, p. 4.

Issue	What we heard	How we responded
Productivity growth	Whilst CCP14 welcomed Ergon Energy offering additional productivity growth, they raised concerns about the reliance on ICT expenditure to underpin this productivity growth.[10] They argued it would be beneficial to see a clearer linkage between ICT investment and productivity improvement.[11] They also noted the 2.58 per cent per year productivity improvement figure proposed by Ergon Energy had not been derived clearly or in detail.[12] Dynamic Analysis noted Ergon Energy should be commended for embedding the savings from their new digital strategy into its opex forecasts.[13]	Our internal forecast adopts both the AER's productivity factor as well as those additional efficiency savings that we have business case plans for achieving including from our planned ICT and property investments.
Output growth / labour price growth	Origin Energy encouraged the AER to test Ergon Energy's price and output growth forecasts.[14] Dynamic Analysis noted that while forecast growth in energy volumes and customer numbers are higher than actuals in the 2015–20 period, the overall output growth forecast appears reasonable.[15]	For our internal forecast we updated our output factors for updated demand, energy and customer number forecasts.
Step changes	CCP14 was pleased to observe the absence of step changes.[38]	For our internal forecast we applied only negative step changes for quantified savings arising from our planned ICT and property investments.
Bushfire risk and vegetation management	The Electrical Safety Office noted that Ergon Energy's proposal did not include enough detail on these areas to make an informed comment.[39]	We are committed to best practice asset management strategies, and whilst ever evolving and changing, we will continue to adapt both strategically and operationally to ensure the safe and reliable operation of our network in consideration of the Queensland environment. This includes development and applying bushfire mitigation strategies (set out in our Bushfire Risk Management Plan) that provide a specific, targeted, measurable and costed approach. Critically, we must ensure that our assets are managed to minimise the risk of bushfires to the network, maintain customer supply reliability and ensure a high level of safety for the community during times of bushfire

7.2.2 AER's draft decision feedback

Attachment 6 to the AER's Draft Decision set out its specific feedback on our opex forecast. Our revised opex forecast is equivalent to the AER's Draft Decision which accepted our Regulatory Proposal amount.

7.3 Our Revised operating expenditure and its basis

Our revised opex forecast is presented in Table 21. As shown, our revised opex is equivalent to our Regulatory Proposal which was accepted by the AER in its Draft Decision. It is $133 million (real $2019-20) lower than our internal opex forecast using the AER's base-step-trend method for 2020-25.

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[10] CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 Regulatory Proposals*, May 2019, p. 8.
[11] CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 Regulatory Proposals*, May 2019, p. 13.
[12] CCP14, *Advice to the AER on the Energex and Ergon Energy 2020–25 Regulatory Proposals*, May 2019, p. 13.
[13] Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020–25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 48.
[14] Origin Energy, *Letter to Mr Sebastian Roberts RE: QLD Regulatory Proposal 2020-25*, May 2019, p.2.
[15] Dynamic Analysis, *Technical regulatory advice to the ECA, Review of 2020-25 regulatory proposals, Energex and Ergon Energy*, May 2019, p. 34.

Table 21: Ergon Energy's Revised Proposal operating expenditure forecast

$million real $2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	Total
Regulatory Proposal	376.83	371.58	367.00	362.06	357.17	**1,834.63**
AER DD Alternative Forecast	389.63	391.35	392.85	394.46	395.89	**1,964.18**
AER Draft Decision	376.83	371.57	367.00	362.06	357.17	**1,834.63**
Internal Forecast	390.24	392.77	394.25	394.75	396.36	**1,968.36**
Revised Regulatory Proposal	376.83	371.57	367.00	362.06	357.17	**1,834.63**

7.4 Supporting documentation

The following documents supporting this chapter accompany our Revised Regulatory Proposal. Those that specifically relate to our internal opex forecast are considered confidential.

Name	Ref	File name
Opex attachment	7.001	EGX ERG 7.001 Opex attachment DEC19 CONFID
Opex Negative Step Changes	7.002	EGX ERG 7.002 Opex Negative Step Changes DEC19 CONFID
Critique of AER Approach	7.003	EGX ERG BIS Oxford Economics 7.003 Critique of AER Approach DEC19 PUBLIC
Escalations independent expert report	7.004	EGX ERG BIS Oxford Economics 7.004 Escalations independent expert report DEC19 PUBLIC
Frontier Report	7.005	EGX ERG Frontier 7.005 Frontier Report DEC19 PUBLIC
Opex forecast – SCS	7.006	ERG 7.006 Opex forecast – SCS DEC19 CONFID
CAM Reconciliation	7.007	EGX ERG 7.007 CAM Reconciliation DEC19 CONFID
PWC Report - CAM Reconciliation	7.008	EGX ERG 7.008 PWC Report - CAM Reconciliation PWC DEC19 CONFID

8. Rate of return, inflation, debt and equity raising costs

8.1 Rate of return

The AER's 2018 Rate of Return Instrument specifies how the AER will estimate the return on debt, the return on equity, and the overall rate of return for our 2020-25 regulatory control period. The Rate of Return Instrument is binding on us and the AER under the NEL.

Our Regulatory Proposal applied the Rate of Return Instrument and we estimated a placeholder allowed rate of return of 5.46 per cent (nominal vanilla). In turn, the AER's Draft Decision applied a placeholder allowed rate of return of 4.87 per cent (nominal vanilla). To prepare this Revised Regulatory Proposal we have applied a placeholder allowed rate of return of 4.67 per cent (nominal vanilla). The actual allowed rate of return will be calculated in the AER's Final Determination consistent with our nominated averaging periods, which were approved in the Draft Decision. Table 22 outlines placeholder allowed rate of return. The rate of return will be updated annually during the 2020-25 regulatory control period as a result of the annual update of the return on debt under the trailing average approach.

Table 22: Rate of Return

Parameter	Current 2015-20 Regulatory Period	Our Regulatory Proposal	AER Draft Decision	Our Revised Regulatory Proposal	Allowed return over
Nominal risk-free rate	2.96%	2.60%	1.32%	0.90%	
Market risk premium	6.50%	6.10%	6.10%	6.10%	
Equity beta	0.70	0.60	0.60	0.60	
Return on equity (nominal post-tax)	7.50%	6.26%	4.98%	4.56%	Constant
Return on debt (nominal pre-tax)	5.01%	4.92%	4.79%	4.75%	Updated annually
Gearing	60.00%	60.00%	60.00%	60.00%	
Nominal Vanilla WACC	6.01%	5.46%	4.87%	4.67%	Updated annually for return on debt
Value of imputation credits (Gamma)	0.40	0.585	0.585	0.585	
Expected inflation	2.50%	2.42%	2.45%	2.37%	Constant

8.2 Expected inflation

We note that a forecast of future inflation outcomes is required to calculate the deduction from the annual revenue requirement according to clause 6.4.3(b) (1)(ii) and S6.2.2(c)(4) of the National Electricity Rules. The purpose of this calculation is to reduce the revenue required for the allowed return on equity by the extent of inflation indexation of the RAB, which, under the regulatory framework, is assumed to accrue to equity holders.

We have computed a forecast inflation figure according to the method currently adopted by the AER, which is to take RBA forecasts for the forthcoming two years, assume that actual inflation will be 2.5% every year for the following eight years and compute the geometric mean of those 10 figures. That approach presently produces a figure of 2.37%.

We consider that the AER's approach to forecasting future inflation is not producing reasonable (or even plausible) forecasts of future inflation over the forthcoming regulatory period. In this regard we consider that there is strong evidence indicating that there is a less than remote chance of inflation averaging 2.37% over the 2020-25 regulatory period. We note that, to the extent that actual inflation turns out to be less than 2.37%, equity investors will be under-compensated relative to the AER's allowed return on equity. For this reason, we request that the AER urgently undertake a full review of its approach to inflation to be completed by the time the AER finalises our distribution determination for the 2020-25 regulatory period. The reasons for this request are explained below.

Operation and implications of the AER's approach to allowed returns and inflation

We note that the interplay between the spreadsheet models developed by the AER is such that:

1. The AER first determines the total allowed return on equity. That figure depends on the prevailing yield of 10-year government bonds and is currently 4.56%.

2. The AER's spreadsheet models then make a deduction for the return that equity holders will receive in the form of inflation indexation of the RAB. The models work by providing that the interest on debt finance must be paid in cash each year, such that the entire benefit of inflation indexation of the RAB flows to equity holders and becomes part of the return to equity. This benefit is then deducted from the allowed return on equity, such that the remainder is available as a cash payment to equity holders. Since, equity represents 40% of the benchmark efficient capital base and the AER's current inflation forecast is 2.37%, the deduction to be made from the total allowed return on equity is 2.37 ÷ 40% = 5.9%.

3. The outcome of the AER's current approach is that the cash available to pay dividends to equity holders is 4.56% - 5.9% = -1.4%. That is, the AER's spreadsheet models currently provide that equity holders must *pay in* 1.4% of the equity capital base each year – because they are due to receive a total return of only 4.56% p.a. and are expected (according to the AER's inflation forecast) to benefit to the tune of 5.9% p.a. from RAB indexation.

4. In summary, under the AER's current approach, not only is there no cash available to pay any dividends at all to equity holders; rather equity holders are required to effectively *pay* to the extent that the AER's estimate of the benefits of RAB indexation exceed the AER's estimate of the required return on equity. This results in us being allowed a negative net profit after tax under the AER's current approach.

We highlight two important problems with this situation under the AER's current approach:

1. **Under-compensation**: There is no reasonable prospect of equity holders benefitting by 5.9% p.a. from RAB indexation – their returns will be reduced as though they received a 5.9% benefit, but the actual benefit is highly likely to be materially lower than that (as explained further below)

2. **Unsustainability**: Even if the AER's figures are all correct, a regulatory regime that forces the regulated business into a loss-making position, and which requires an annual equity contribution to offset assumed RAB growth, is clearly not sustainable.

These problems of under-compensation and unsustainability are caused by the relationship between the AER's estimates of the total allowed return on equity and expected inflation. The AER's approach always estimates expected inflation to be approximately 2.5% in all market conditions. By contrast, the estimate of the allowed return on equity is made by adding a constant risk premium to the prevailing nominal government bond yield, which at the current level of 0.9%, reflects expected inflation very materially lower than 2.5%.

Current market conditions

In the current financial market conditions, the AER's approach to the allowed return on equity and forecasted inflation produces unreasonable outcomes whereby the benchmark efficient firm is considered to be one that incurs an annual loss (NPAT) and requires an equity injection each year, and where equity holders will only receive the record low return currently allowed by the AER if inflation turns out to average 2.37% over the next regulatory period.

We consider that there is sufficient evidence that it is unreasonable to consider that inflation is likely to average 2.37% over the forthcoming regulatory period.

For example, in November 2019 the RBA commented that:

> *The central scenario remains for inflation to pick up, but to do so only gradually. In both headline and underlying terms**, inflation is expected to be close to 2 per cent in 2020 and 2021.***
>
> *Given global developments and the evidence of the spare capacity in the Australian economy, **it is reasonable to expect that an extended period of low interest rates will be required** in Australia to reach full employment and achieve the inflation target.*[16]

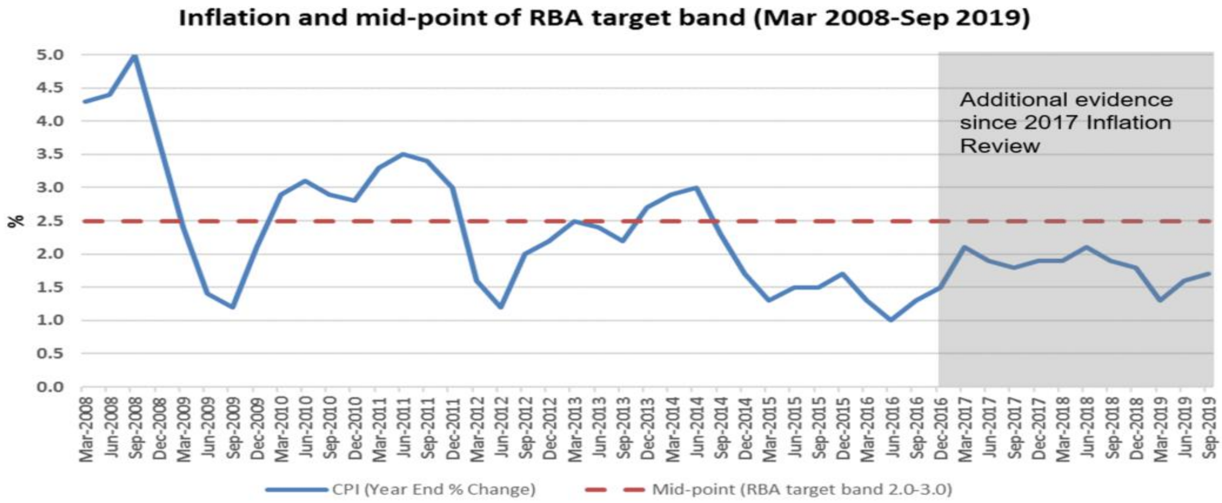
The RBA view was noted by the financial press, for example:

> *The Reserve Bank has abandoned is expectation for any pick-up in wage growth in its forecast period and says **inflation will now not reach the bottom of its targeted 2-3 per cent range until 2022 at the earliest**.*[17]

In addition, it is now the case that actual inflation has now been below 2.5% for 20 consecutive quarters, which is unprecedented since the RBA began inflation targeting in the mid-1990s, as illustrated in Figure 12.[18]

[16] Statement by Philip Lowe, Governor: Monetary Policy Decision, 5 November 2019, emphasis added.
[17] The Australian, 7 November 2019.
[18] https://www.abs.gov.au/ausstats/meisubs.nsf/log?openagent&640101.xls&6401.0&Time%20Series%20Spreadsheet&601AC6E077B33C27CA2584A20012CAC5&0&Sep%202019&30.10.2019&Latest.

Figure 12 RBA inflation target and outcomes



Moreover, the forecasts of future inflation published by the RBA (including market-based and survey measures) are all at, or very close to, their historical lows. These forecasts have all fallen materially since the AER's last inflation review, as illustrated in the table below.[19]

Table 23: Forecasting Inflation

Method	Current estimate percentile rank	Dec 2017 (AER review) percentile rank
Consumer expectations	6%	73%
Business expectations	11%	21%
Union officials (1-year)	4%	7%
Union officials (2-years)	1%	6%
Market economists (1-year)	1%	15%
Market economists (2-years)	0%	8%
Breakeven (10-year)	0%	8%

In a recent research note, AMP Capital has noted that the RBA has consistently forecast inflation returning quickly towards the mid-point of its target band, even as actual inflation has consistently moved in the opposite direction. This is illustrated in Figure 13, which shows that, in forecast after forecast after forecast, the RBA has badly mis-estimated actual inflation.

[19] https://www.rba.gov.au/statistics/tables/xls/g03hist.xls.

Figure 13 RBA inflation forecasts

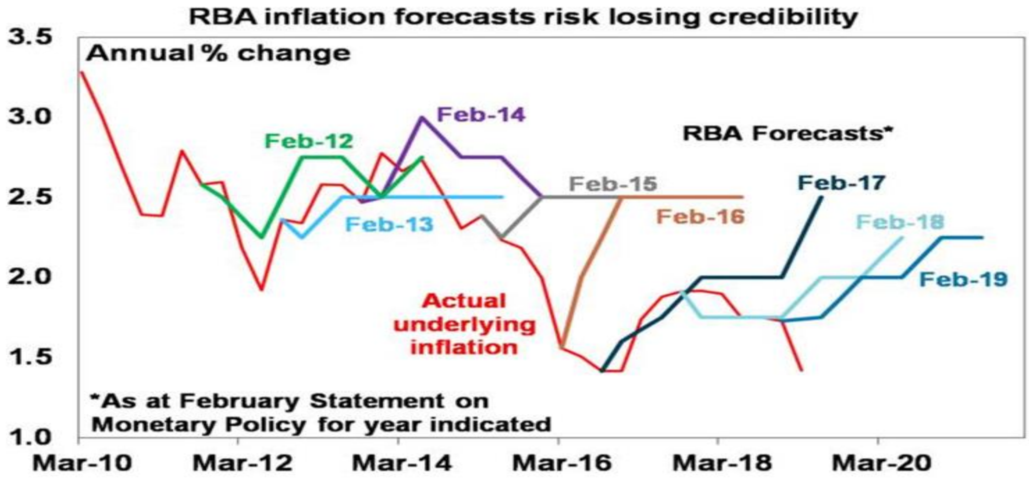


Figure 13 shows that, in 2017 when the AER's inflation review was conducted, the RBA was forecasting inflation to return to 2.5% within two years. Two years later, actual inflation has turned out to be only 1.5%. Indeed, since 2014, the RBA has uniformly over-estimated future inflation, in most cases by a material amount.

Other regulatory views about inflation

In its 2018 Rate of Return Guidelines Explanatory Statement, the ERA explained the reasons for its rejection of the AER approach to inflation in the current financial market conditions. The ERA rejected the approach of assuming that inflation will return immediately and permanently to 2.5% after two years:

> *…given the weight placed on the mid-point of the RBA's target inflation, the inflation forecast remains relatively constant over time and will not reflect changing inflation expectations. The mid-point of the RBA's inflation band is therefore not as dynamic as a market based measure.*
>
> *There is evidence that the RBA inflation forecast and target band method has not responded to the changing inflation environment and leads to an overestimate of expected inflation.* [20]

As set out above, the RBA has more recently conceded that it considers it to be unlikely that inflation would return to 2.5% after two years in the current financial market conditions.

The ERA went on to note the serious implications of setting allowed returns in a way that embeds an implied negative real risk-free rate:

> *Given the lag in the RBA inflation forecast method, it can result in a negative real risk free rate when the Fisher equation is used. An expected negative real risk free rate is likely to have adverse regulatory implications, since investors would be unwilling to lend funds with an expected negative real rate of return, when withholding investment offers a zero per cent rate of return.*

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[20] ERA, 2018 Rate of Return Guidelines Explanatory Statement, paragraphs 1580-1581.

Negative expected real rates of return may occur when the RBA overestimates the expected inflation rate. Applying the nominal risk free rate observed from the market, in conjunction with the inflation forecast from the RBA, to the Fisher equation will return a negative real risk free rate under these circumstances. [21]

This analysis led the ERA to adopt a 'breakeven' estimate of inflation, derived from the yields on real and nominal government bonds. The ERA concluded that:

In this approach, estimates of both the nominal and real risk free rates of return are directly observed from the financial markets, so reflect the market expectation for inflation. [22]

The Independent Panel endorsed that approach:

The Independent Panel considered that the ERA's Treasury bond implied inflation approach was well-explained, based on sound reasoning and, given its use of appropriate market information, likely to be the best means of forecasting inflation. [23]

Conclusion

We consider that the AER's approach to forecasting future inflation is not producing reasonable (or even plausible) forecasts of future inflation over the forthcoming regulatory period. In this regard we consider that there is strong evidence indicating that there is a less than remote chance of inflation averaging 2.37% over the 2020-25 regulatory period. There is no evidence that inflation will return to 2.5% immediately after the second year of the forthcoming period. We note that, to the extent that actual inflation turns out to be less than 2.37%, equity investors will be under-compensated relative to the AER's allowed return on equity. For this reason, we request that the AER undertake a full review of its approach to inflation and implement an improved approach in our distribution determination for the 2020-25 regulatory control period.

8.3 Debt raising costs

Debt raising costs are the transaction costs incurred each time debt is raised or refinanced and the costs for maintaining the debt facility. Our Revised Regulatory Proposal accepts the AER's Draft Decision to apply its standard estimation approach which is based on the report from the Allen Consulting Group (ACG), commissioned by the Australian Competition and Consumer Commission (ACCC) in 2004. We also accept the update of the allowance using estimates from Chairmont's 2019 report.

8.4 Equity raising costs

Equity raising costs are transaction costs incurred when raising new equity. Our Revised Regulatory Proposal accepts the AER's Draft Decision to apply its benchmark approach. We have estimated no equity raising costs.

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[21] ERA, 2018 Rate of Return Guidelines Explanatory Statement, paragraphs 1582-1583.
[22] ERA, 2018 Rate of Return Guidelines Explanatory Statement, paragraph 1591.
[23] ERA, 2018 Rate of Return Guidelines Explanatory Statement, paragraph 1585.

9. Incentive schemes

We consider that the application of incentive schemes is in the long-term interests of our customers, as they align our interests with theirs. Our Revised Regulatory Proposal accepts the AER's Draft Decision to apply each of the following schemes in the 2020-25 regulatory control period:

- an efficiency benefit sharing scheme (EBSS)[1]
- a capital expenditure sharing scheme (CESS)[1]
- a service target performance incentive scheme (STPIS)[1]
- a demand management innovation allowance mechanism (DMIAM)[1],
- a demand management incentive scheme (DMIS)[1]

Our Revised Regulatory Proposal includes EBSS and CESS carryovers in our forecast revenues. The is a departure from our Regulatory Proposal position. In our Regulatory Proposal we proposed to forgo the incentive revenue from CESS and EBSS from the 2015-20 period to meet our affordability commitment and noted we would reassess if required to ensure that our proposal continues to provide a balanced approach in the long-term interests of customers. Our financial circumstances have changed since our Regulatory Proposals leading us to reclaim the incentive scheme revenues. More specifically, our revenues have declined materially as a result of the substantial reduction in interest rates (and the rate of return) and changes in the regulatory tax approach. We are now faced with a much greater challenge to fund critical investments and our ongoing and emergency maintenance activities. We have had to recalibrate how we fund critical safety, security and sustainability commitments whilst still ensuring we continue to meet our affordability commitment. This is vital to ensuring the viability of our business isn't jeopardised.

9.1 EBSS

The EBSS encourages distributors to continuously pursue opex efficiency improvements and share these with customers.

9.1.1 Carryover amounts from the 2015–20 regulatory control period

Our Revised Regulatory Proposal include EBSS carryover amounts from the 2015-20 period in our forecast revenues. This is a departure from our Regulatory Proposal position to forgo the EBSS revenue.

We have updated the AER's calculations of EBSS rewards in the Draft Decision to reflect:

- audited actual opex in 2018-19
- latest forecast of inflation for 2019–20 from the Reserve Bank of Australia (RBA)
- base year emergency response normalisation (discussed below and in Attachment 7.001)
- amendments to reported opex for overhead recoveries true-up (discussed below and Attachment 7.001)

Table 24 sets out our updated EBSS revenue increments.

Table 24 EBSS

$M Real $2020	Draft Decision	Revised Proposal
EBSS carryovers	157.63	193.93

Ergon emergency response normalisation

As we outline in Attachment 7.001, we incurred noticeably higher emergency response expenditure in 2018-19, our nominated base year, relative to prior years. We intended on reducing our base year by $12.16 million (real, $2019-20) to reflect normalised level of emergency response expenditure.

We propose to include this adjustment in calculating our 2015-20 EBSS carry-overs using the non-recurrent efficiency gain mechanism. We acknowledge the AER's Draft Decision view that this mechanism was introduced, in 2013, to address situations where there was a significant non-recurrent efficiency gain in the base year and consequently the base year was abnormally low. However, we consider that this mechanism could also be used in situations where the base year in abnormally high for justifiable reasons. We intended to propose the use of this mechanism to shift revenue from opex allowances to EBSS carryovers, by reducing opex to a normalised level and increasing the EBSS carryovers.

This adjustment also ensures alignment between the EBSS and Base-Step-Trend opex forecasting approach. Aligning the two ensures that the EBSS works as intended i.e. we retain approximately 30% of incremental efficiency gains or losses.

Ergon Energy Overhead Recoveries True-up

We have included an adjustment to our reported actual opex for 2015-16 to 2018-19 in the EBSS model, which corrects our reported opex to account for the treatment of under/over recovery of overheads. We outline the issue in the Attachment 7.001.

9.1.2 Application in the 2020–25 regulatory control period

Our Regulatory Proposal supported the Framework and Approach (F&A) decision to continue to apply the EBSS (version 2.0) in the 2020-25 regulatory control period. The Draft Decision accepts our proposal. Key elements of version 2.0 of the EBSS are:

- The length of the carryover period will be the same as the length of our following regulatory control period (i.e. 5 years)
- Adjustments to forecast or actual opex in calculating carryover amounts include adjustments to:
  - exclude debt raising costs as these are not forecast on a revealed cost basis
  - forecast opex to add (subtract) any approved revenue increments (decrements) made after the initial regulatory determination, such as approved pass through amounts or opex for contingent projects
  - actual opex to remove DMIA opex because it is not included in the opex forecast
  - actual opex to add capitalised opex that has been excluded from the regulatory asset base
  - forecast opex and actual opex for inflation
  - actual opex to reverse any movements in provisions

We accept the Draft Decision as it relates to the application of the EBSS over the 2020-25 regulatory control period. We have updated the calculation of the forecast opex subject to EBSS as detailed in Table 25:

Table 25 Forecast opex for EBSS

$M Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25
Total forecast opex (internal)	376.83	371.57	367.00	362.06	357.17
Less debt raising costs	5.62	5.66	5.71	5.75	5.78
Forecast opex for EBSS	371.21	365.91	361.30	356.31	351.39

9.2 CESS

The CESS encourages distributors to undertake efficient capex over the regulatory control period. Any resulting efficiency gains are shared with customers.

9.2.1 CESS revenue increments from the 2015–20 regulatory control period

Our Revised Regulatory Proposal include CESS revenue increments from the 2015-20 period in our forecast revenues. This is a departure from our Regulatory Proposal position to forgo the CESS revenue.

We have updated the calculations of the CESS revenue increments to reflect actual 2018-19 capex, weighted average cost of capital (WACC) and recent inflation figures. Table 26 sets out our updated CESS revenue increments.

Table 26 CESS

$M Real $2020	Draft Decision	Revised Proposal
CESS	45.11	46.13

9.2.2 Application of scheme in 2020–25 regulatory control period

Our Regulatory Proposal supported the F&A decision to continue to apply the CESS (version 1) in the 2020-25 regulatory control period. The Draft Decision accepts our proposal.

We accept the Draft Decision as it relates to the application of the CESS in the 2020-25 regulatory control period.

9.3 STPIS

The STPIS incentivises us to maintain or improve service performance where customers are willing to pay for the improvements. The STPIS is intended to balance incentives to reduce expenditure with the need to maintain or improve service performance.

Our Revised Regulatory Proposal accepts most elements of the Draft Decision in relation to the application of the STPIS, which were consistent with our Regulatory Proposal and the Framework and Approach paper. Table 27 below sets out the key STPIS elements accepted in the Draft Decision.

Table 27 Key STPIS elements

Issue	Our Regulatory Proposal	AER Draft Decision
Revenue at risk	±2 per cent	Accepted
Segmenting of network	Central Business District (CBD), urban, short rural and long rural	Accepted
Applicable parameters for the s-factor	Reliability of supply: system average interruption duration index (SAIDI) and system average interruption frequency index or (SAIFI) Customer service: telephone answering	Accepted
Performance targets	Based on the average performance over the past five regulatory years.	Accepted
Criteria for excluding certain events from s-factor calculations	Applied the methodology indicated in the national STPIS – the 2.5 beta method for calculating major event days (MED)	Accepted
Incentive rates	Applied the methodology indicated in the national STPIS and the value of customer reliability (VCR) for Queensland from AEMO's 2014 study.	Accepted, but noted that the VCR will be updated following the completion of the AER's VCR Study in December 2019
GSL component	Not applied	Accepted

In addition, we support the application of version 2.0 of the STPIS published in November 2018. Key changes in the revised STPIS include:

- the change of momentary interruption threshold from 1 minute or less to 3 minutes or less
- adjusting the incentive rate weighting between SAIDI and SAIFI from the current approximately 50:50 ratio to 60:40 ratio.

9.3.1 Reliability of supply targets and incentive rates

Our Revised Regulatory Proposal propose the following STPIS targets and incentives rates.

Table 28 STPIS Incentive Rates and Targets Error! Not a valid link.

In calculating these incentive rates and targets, we:

- Amended the AER's Draft Decision model to accurately give effect to the adjustment for performance over the cap (we discuss our approach below)
- Updated the data used to calculate the targets and incentive rates. More specifically we have
  - based our revised targets on the 5-year period from 2014-15 to 2018-19 (back-cast consistent with version 2.0 of the STPIS). In our Regulatory Proposal, we used placeholder data for the 5-year period from 2013-14 to 2017-18 because actual data for 2018-19 was not yet available
  - updated the forecast revenue consistent with our Revised Regulatory Proposal
  - used the Value of Customer Reliability (VCR) rates in the Draft Decision (based on the AEMO 2014 study) to calculate the reliability incentive rates. We accept the AER's

position that these are only placeholder values until the current AER's VCR study is completed later this year.

The amended model is provided as Attachment 9.001 "STPIS Targets and Incentive Rates"**.**

9.3.2 Adjusted performance targets for past STPIS rewards/penalties

In accordance with Clause 3.2.1(a)(1B) of the STPIS, performance targets must be adjusted for instances where past performance exceeded the revenue at risk thresholds. This adjustment ensures that future performance targets reflect the actual financial rewards or penalties that were received or paid by the distributor. The adjustment prevents a distributor from benefiting (or being penalised) from poor (or exceptional) historical performance through relaxed (or stringent) targets when the distributor was not equivalently penalised (or rewarded) for the poor (or exceptional) historical performance due to the penalties (or rewards) being capped. Put differently, the adjustment prevents windfall gains or losses in setting performance targets.

While the STPIS has always provided for this adjustment, previous versions of the scheme did not stipulate a specific method for making this adjustment. Distributors could propose a suitable method in their regulatory proposals. Indeed, we did so in the 2015-20 distribution determination and the AER accepted our proposed approach.

The recently developed version 2.0 of the STPIS includes a method for making the adjustment. However, our Regulatory Proposal noted that the AER's approach was unclear and we proposed to apply an alternative method that was used in the 2015-20 distribution determination. The AER's Draft Decision rejected our proposal and states that:

> *We consider that the STPIS scheme document provides sufficient details to perform the calculations and must be adhered to.*[24]

We maintain that, at the time of preparing our Regulatory Proposals, the method set out in version 2.0 of the STPIS scheme document was unclear. We have since developed a better understanding of the STPIS method after reviewing the model developed by the AER to calculate our proposed targets for the 2020-25 regulatory control period (and give effect to the adjustment). The AER provided us with the model, for review, on 15 August 2019, prior to the publication of the Draft Decision. We proposed several modifications to the AER's calculations including (and perhaps most importantly) that all the years in the historical target setting period where performance was exceeded must be considered cumulatively in making the adjustment to targets.

However, we note that the Draft Decision did not appropriately consider our proposed modifications to the AER's STPIS model. Based on the reliability data used in the Draft Decision, the Table 29 demonstrates that our proposed amendments to the AER's approach are non-trivial.

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[24] AER, Attachment 10: Service target performance incentive scheme | Draft decision – Energex 2020–25 p10

Table 29 STPIS targets comparison

Parameter	AER Draft	Amended	% Difference
Unplanned SAIDI - CBD			
Unplanned SAIDI - urban	91.813	116.661	27.06%
Unplanned SAIDI - short rural	249.587	274.435	9.96%
Unplanned SAIDI - long rural	740.653	765.500	3.35%
Unplanned SAIFI - CBD			
Unplanned SAIFI - urban	1.059	1.216	14.83%
Unplanned SAIFI - short rural	2.361	2.518	6.65%
Unplanned SAIFI - long rural	5.073	5.230	3.09%

We engaged again with the AER on the issue following the publication of the Draft Decision and the AER informally accepted our proposed modifications but advised us to include the modifications in our Revised Regulatory Proposal.

9.3.3 Customer service targets and incentive rates

Table 30 sets out our revised targets for the telephone answering. The targets have been updated to include the 2018-19 year. The detailed calculations are provided in the attached STPIS model.

Table 30 Customer Service targets

Parameter	Incentive Rates	Target
Telephone answering	-0.04	79.91

9.4 Demand management incentives

The demand management incentive framework in the NER incentivises us to pursue efficient demand management projects when these are at least as efficient as network capital investment. We accept the Draft Decision to apply the demand management schemes (the DMIS and the DMIAM) over the 2020-25 regulatory control period. Table 33 below sets out the DMIAM funding for the 2020-25 regulatory control period.

Table 31 Demand Management Incentives

$M Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25
DMIA	1.07	1.06	1.07	1.03	1.02

The demand management incentive totals $5.24 million over the 5-year period.

9.5 Supporting documentation

The following documents supporting this chapter accompany our Revised Regulatory Proposal:

Name	Ref	File name
STPIS Targets and Incentive Rates	9.001	ERG 9.001 STPIS Targets and Incentive Rates DEC19 PUBLIC
Efficiency Benefit Sharing Scheme (EBSS) Model	9.002	ERG 9.002 Efficiency Benefit Sharing Scheme (EBSS) Model DEC19 PUBLIC
Capital Expenditure Sharing Scheme (CESS) Model	9.003	ERG 9.003 Capital Expenditure Sharing Scheme (CESS) Model DEC19 PUBLIC

10. Other constituent decisions

While the revenue building blocks constitute the main elements of our allowed revenue, the AER is required to make decisions relating the classification of services, control mechanisms and pricing structures and policies. In the main, these are addressed in the AER's F&A decisions. This Revised Regulatory Proposal continues our adoption of the AER's F&A paper, with minor modifications. These include the modifications made by the AER in its Draft Decision relating to pass-through events and classification of services.

10.1 Pass-through events

The AER accepted our four nominated pass-through events with minor changes to the definitions to ensure consistency with its recent decisions for other network service providers. We have accepted and adopted these updated definitions for our Revised Regulatory Proposal as set out in Table 32.

Table 32 Pass through event definition

Pass through event	Approved definition
Insurance cap	An insurance cap event occurs if: • we make a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy, • we incur costs beyond the relevant policy limit, and • the costs beyond the relevant policy limit materially increase the costs to us in providing direct control services. For this insurance cap event: • A relevant insurance policy is an insurance policy held during the 2020-25 regulatory control period or a previous regulatory control period in which we were regulated, and • we will be deemed to have made a claim on a relevant insurance policy if the claim is made by a related party ours in relation to any aspect of our network or business. Note: In assessing an insurance cap event cost pass through application under rule 6.6.1(j), the AER will have regard to, amongst other things: • the relevant insurance policy for the event, and • the level of insurance that an efficient and prudent NSP would obtain in respect of the event.

Insurer credit risk	An insurer credit risk event occurs if:
	• An insurer of ours becomes insolvent, and as a result, in respect of an existing or potential claim for a risk that was insured by the insolvent insurer, we:
	  ○ are subject to a higher or lower claim limit or a higher or lower deductable than would have otherwise applied under the insolvent insurer's policy; or
	  ○ incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.
	Note: In assessing an insurer credit risk event pass through application, the AER will have regard to, amongst other things:
	• Our attempts to mitigate and prevent the event from occurring by reviewing and considering the insurers track record, size, credit rating and reputation, and
	• in the event that a claim would have been made after the insurer became insolvent, whether we had reasonable opportunity to insure the risk with a different insurer.

Natural Disaster	Natural disaster event means any natural disaster including but not limited to cyclone, fire, flood or earthquake that occurs during the 2020–25 regulatory control period that increases the costs to us in providing direct control services, provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider. Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:

Pass through event	Approved definition
	• whether we have insurance against the event, • the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and • whether a relevant government authority has made a declaration that a natural disaster has occurred.
Terrorism	Terrorism event means an act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which: • from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear), and • increases the costs to us in providing direct control services. Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things: • whether we have insurance against the event, • the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and • whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

10.2 Classification of services

The classification of services determines which of our services will be subject to regulation, how we will recover our costs and our ring-fencing obligations over the next regulatory control period.

Our Revised Regulatory Proposal accepts the Draft Decision in relation to the classification of services. The Draft Decision is consistent with our Regulatory Proposal, which aligned with the service groupings and descriptions in the recently developed Service Classification Guideline but retained the substantive classifications set out in the F&A paper.

For the 2020-25 regulatory control period, we propose to use the service classification table outlined in the Draft Decision.

10.3 Control mechanisms

Control mechanisms impose constraints on the revenues we earn or the prices that we charge (or both), in the provision of direct control services (i.e. SCS or ACS).

Our Revised Regulatory Proposal largely accepts the AER's Draft Decision in relation to:

- Application of a revenue cap to SCS and price caps to ACS
- Revenue cap formulae, which have updated following the changes to the STPIS
- Price cap formulae for legacy metering, public lighting and fee-based services and the formulae applying to quoted services
- The requirement to demonstrate compliance with the revenue cap as outlined in the Draft Decision, including adjustment for DUoS under or over recoveries.
- Designated pricing proposal charges
- Jurisdictional scheme amounts
- Rounding of figures in the annual pricing approval process.

However, we propose that the AER amend the side-constraint formulae in the Draft Decision to include the incentive schemes and cost pass through factors.

10.4 Pricing structures and policies

Following submission of our Regulatory Proposal in January 2019, Ergon Energy has continued to directly engage and consult with our stakeholders, customer advocates and customers to obtain further insights into their thoughts and views on our proposed network tariff strategy for the 2020-25 regulatory control period and beyond. The outcomes of this engagement have been reflected in the Revised TSS we have submitted to the AER as part of our Revised Regulatory Proposal.

Further to this stakeholder engagement, Ergon Energy has carefully considered the AER's key findings and recommendations regarding our June 2019 TSS that it set out in its Draft Decision. Ergon Energy broadly accepts the AER's recommendations and has amended its Revised TSS accordingly.

In making these changes, we emphasize our commitment to implementing a network tariff framework in the 2020-25 regulatory control period and beyond that provides better outcomes for customers including: affordability, choice, predictability, targets manageable customer impacts, caters for new technologies and achieves simplicity.

10.5 Connection policy

In its Draft Decision the AER determined our unit rates to be reasonable (based on a comparison with historical costs and the Productivity Commission's previous findings on long run marginal cost of network augmentation), but that they should be expressed in the form of "dollars per kVA", as prescribed in the AER's *Connection charge guidelines for electricity retail customers under chapter 5A of the National Electricity Rules* (*Connection Charge Guidelines*) instead of "dollars per kVA per annum" as we had proposed. We accept the AER's Draft Decision that it is appropriate to express the capital contributions upstream cost charge rates (unit rates) in "dollars per kVA" terms and have included the unit rates recalculated by the AER for residential and non-residential customers in the revised Connection Policy for 2020-2025. We consider this approach to be consistent with the requirements of the *Connection Charge Guidelines*.

However, we do not accept the AER's draft decision that our capital contributions unit rates should be the same as the Energex unit rates due to the application of the Queensland Government's Uniform

Tariff Policy (UTP) to retail electricity prices in regional Queensland. The AER's view is that charging new connections at the full rate would be inconsistent with the NER principles as it would result in an unfair allocation of costs to new customers and cross-subsidisation between new and existing customers. Ergon Energy disagrees with the AER's proposal to use Energex unit rates for the following reasons.

The UTP, while influencing the price that customers in the Ergon Energy distribution area pay for their electricity, is separate and distinct from the setting (and recovery) of network charges by Ergon Energy. The UTP is a jurisdictional policy relating to the determination of *retail electricity prices* that the Ergon Energy Queensland Pty Ltd retail business can charge in regional Queensland. The intent of the UTP is that, "wherever possible, customers of the same class should pay no more for their electricity, regardless of their geographic location".[25] The role of setting notified retail electricity prices to be paid by regional Queensland customers is delegated by the Minister for Natural Resources, Mines and Energy to the Queensland Competition Authority (QCA) in accordance with the power of delegation under section 90AA(1) of the Queensland *Electricity Act 1994*.

The UTP generally results in regional residential, small business and some large business customers paying electricity prices that are lower than the cost of supply for regional Queensland. The shortfall is made up by a subsidy paid by the Queensland Government to compensate Energy Queensland's retail business via a Community Service Obligation (CSO) payment. While the notified retail prices for some customers are constructed using the Energex network charges, Ergon Energy recovers the full Ergon Energy network charges from the retail business. The Queensland Government's CSO payment is intended to subsidise the retail business for the difference between the substituted network charges used to calculate the notified retail prices and the network charges paid to Ergon Energy by the retail business.

As the UTP is a jurisdictional policy relating to the determination of regional retail electricity prices, Ergon Energy does not take the UTP into consideration when undertaking the cost-revenue-test to determine if a capital contribution will apply for network connection services.

The cost-revenue-test takes into account the incremental revenue the connection will generate for the network business against the incremental cost to determine if there is a shortfall that requires a capital contribution. The Ergon Energy network charges are used when calculating the incremental revenue component of the cost-revenue-test (IR(N=X)), not the substituted network charges used by the QCA to calculate the notified retail prices.

Ergon Energy considers that it is important that the unit rates should reflect the true costs of augmentation works to send appropriate signals to customers about the costs of providing connection services. This is particularly important in regional Queensland where the costs of providing electricity services is much higher than that in South-East Queensland. The AER's proposed approach to use Energex unit rates rather than Ergon Energy unit rates would significantly reduce the amount of capital contributions paid by customers towards augmentation of the shared network in regional Queensland. Ultimately, this shortfall will only serve to increase our network tariffs. As network costs in regional Queensland are typically higher than those in South-East Queensland due to significant differences in network characteristics, we consider that it is important that the unit rates should reflect the true costs of augmentation works to send appropriate signals to customers about the costs of providing connection services at that location. This is particularly the case given the network charges Ergon Energy uses to calculate incremental revenue for the

[25] Minister for Natural Resources, Mines and Energy, *Electricity Act 1994 Section 90AA(1) Delegation*, 17 December 2018, clause 5(b).

purposes of the cost-revenue-test are reflective of the true costs Ergon Energy incurs for the provision of network services to the customer over the assumed life of the connection.

We remain committed to providing timely and affordable network connections. Utilising our network charges will effectively:

- Allow customers to make efficient locational and investment decisions;
- Minimise inefficient network investment and avoid expensive network upgrades that may be uneconomic; and
- Result in lower average network prices and more efficient outcomes for customers in the long run.

Finally, it should be noted that the UTP applies mainly to small regional Queensland customers and that the vast majority of those customers will fall below the shared network augmentation charge thresholds and therefore will not be required to pay a capital contribution towards the cost of network augmentation. To the extent that the cost-revenue-test will apply, we consider it is important that our unit rates should be used to provide a user-pays signal that reflects the true costs of providing the connection services.

In light of the above, Ergon Energy does not believe that using the proposed Ergon Energy unit rates would be inconsistent with NER principles and or result in an unfair allocation of costs to new customers and cross-subsidisation between new and existing customers. As part of this Revised Regulatory Proposal we have included a revised Connection Policy reflecting the Ergon Energy unit rates recalculated by the AER as “dollars per kVA” for approval.

10.6 Supporting documentation

The following documents supporting this chapter accompany our Revised Regulatory Proposal:

Name	Ref	File name
Attachment A – Ergon Energy 2020-25 Indicative Pricing Schedule	10.001	ERG 10.001 Attachment A – Ergon Energy 2020-25 Indicative Pricing Schedule DEC19 PUBLIC
Attachment B - Customer Impact Analysis report	10.002	EGX ERG 10.002 Attachment B - Customer Impact Analysis report UNSW DEC19 PUBLIC
2020-25 LRMC Model	10.003	ERG 10.003 2020-25 LRMC Model DEC19 PUBLIC
2020-25 Revised Tariff Structure Statement	10.004	ERG 10.004 2020-25 Revised Tariff Structure Statement DEC19 PUBLIC
2020-25 Revised TSS Explanatory Notes	10.005	ERG 10.005 2020-25 Revised TSS Explanatory Notes DEC19 PUBLIC
Attachment B - Customer Impact Analysis report (Addendum)	10.006	EGX ERG 10.006 Attachment B - Customer Impact Analysis report (Addendum) UNSW DEC19 PUBLIC

11. Alternative control services (ACS)

11.1 Our approach

Our revised proposal for ACS remains consistent with the approach we developed with customers during the development of our Regulatory Proposal. This approach was largely accepted by the AER in its Draft Decision. Our revised approach continues to use the same pricing methodologies and models as those used in our Regulatory Proposal, with the same updated assumptions for rate of return, inflation and labour price growth as contained in our Standard Control Services (SCS) as presented above. These assumptions are set out in Table 33.

11.2 The AERs feedback

Table 33 Our ACS response to the Draft Decision

ACS	RP	AER DD	RRP
Public Lighting	- Extensive 47% targeted LED rollout by 2025 - New LED specific NPL1 and NPL2 tariffs, with customers transitioning within tariff categories and without exit fees - New NPL4 tariff for customer funded replacement of conventional luminaire and lamp to LED (recognising that the associated pole and cabling are non-contributed) - Consistent asset base, base-step trend and pricing approach with overall network business - A new public lighting SCS metered supply tariff in the event of a future amendment to the metrology requirements	- Accepted LED rollout and asset management plan - Accepted tariff structure including - asset allocation within NPL2 asset base - Creation of NPL4 tariff category - Reduced proposed public lighting tariffs - WACC and regulatory tax approach - Allocation of overheads - Rejected the inclusion of public lighting metered supply tariff (SCS)	Accept in-principle approach of AER. Reallocation of overheads and update for the latest available information. Clarification of application of tariffs.
Metering Services	- No longer responsible for new meters, Ergon Energy has virtually no direct capex and Energex has none only - Included non-network capex allocations, consistent asset base, base-step trend and pricing approach with SCS	- Adjusted for WACC and labour escalators - Rejected Energex's non-direct capex and operating expenditure	Expensing of non-network capex. Reallocation of overheads and update for the latest available information.
Ancillary (fee-based and quoted) services	- Cost reflective - Increased consistency between Energex and Ergon Energy - Increased transparency and efficiency through use of fee-based rather than quoted mechanism	- Acceptance of overall approach - Adjusted for some labour rates - Impact is very small as only on quoted services (no fee-based services have para-professional content), and regardless of categorisation, the tasks need to be undertaken by suitably qualified individuals. - Ergon Energy's travel time approach approved – with 2-hours charged for long	Adjust for labour rates and update for latest available information.

ACS	RP	AER DD	RRP
		feeders and 20 minutes for short feeders. Provides greater transparency and simplification.	
Security Lights (Watchman Lights)		- Change from 1 July 2020 from unregulated to ACS - AER's endorsement of EQL's approach that security lighting services will be installed on a quotation basis, with a fee basis for ongoing maintenance, operation and replacement costs.	Accept the AER's approach

11.3 Public lighting

We provide public lighting to the 56 local government authorities in our distribution area, the Department of Transport and Main Roads and other Government entities. Our Revised Regulatory Proposal includes our plan, developed with these customers, to accelerate the replacement of existing lights with LEDs, as this technology will lower customers' energy costs. By 2025 we anticipate achieving 47% LED penetration.

We have proposed new LED specific tariffs for each of the four public lighting categories and a new public lighting tariff category (NPL4) for customer funding of NPL1 upgrades to LED luminaires and lamps. These tariffs transparently reflect the lower expected operating costs of LEDs, and thereby providing a price signal to encourage an orderly transition to this technology.

We do not propose any changes in the way the public lighting tariffs are applied. Once established, an asset will remain in the tariff category it has been assigned to, providing continuity and cost surety to customers. We continue to allocate 10% of total public lighting capex to the calculation of the NPL2 tariffs to provide for replacement assets. We have not included a capex allocation for the replacement of assets in the NPL4 category for the 2020-25 regulatory period, however this is expected to be required in future periods.

The AER in its Draft Decision accepted the structure of our approach, but there are material differences in what the AER considered reasonable costs and what we had proposed. We proposed reductions to most public lighting tariffs and the Draft Decision increased these reductions through a proposed cap on overheads at 35% of total opex. We have accepted the AERs methodology, but in doing so needed to correct the allocation of some expenses from overhead to opex. This largely addressed the difference between the Regulatory Proposal and Draft Decision outcomes.

We were invited to provide a more detailed cost build-up approach to our operating expenditure by the AER. In response we have used 2018-19 actual opex as a basis for separating out and calculating maintenance frequency rates for our existing portfolio of luminaires. We found that approximately twenty percent of luminaires requires maintenance each year. We have assumed that only one percent of LEDs will require maintenance in 2020-21, reflecting the expected reliability of the technology and that all LEDs will be new. We increase the maintenance rate for LEDs on a straight-line basis to five percent in 2025. This explicit modelling of LED operating costs ensures the resultant LED tariffs accurately reflect the reliability expectations of both ourselves and our customers.

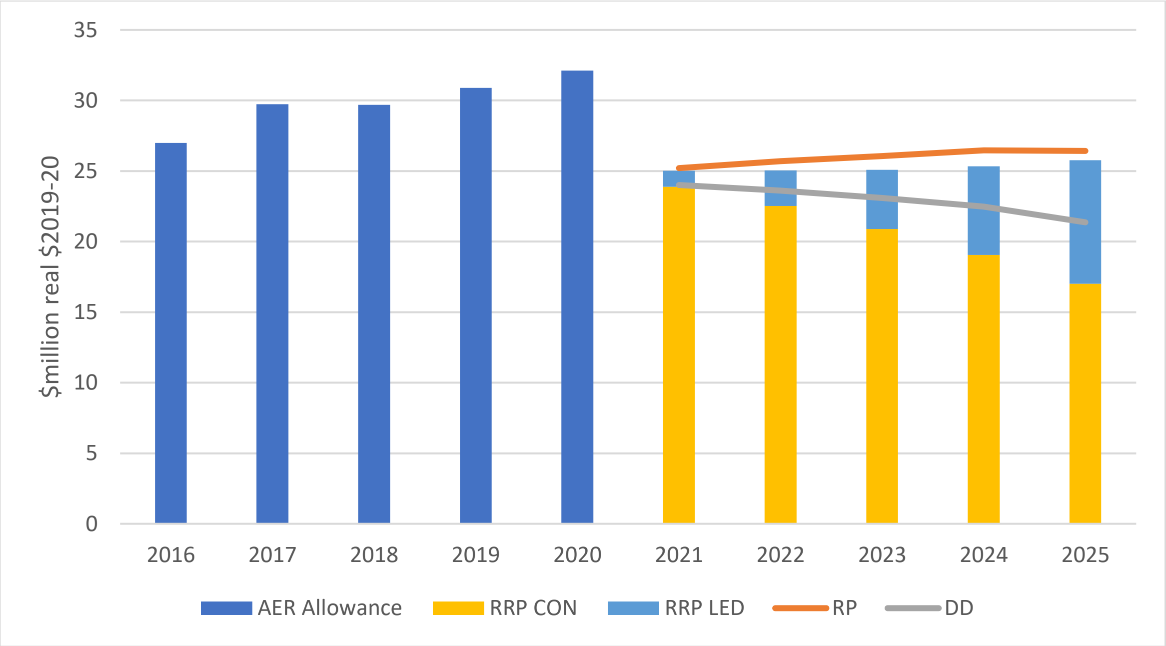
The Draft Decision also included a small modification to the basis for calculating the NPL4 tariff, and a request that our LED tariffs all be calculated using a bottom-up methodology rather than the base-step-trend approach. Table 34 provides the revenue for conventional and LED public lighting respectively.

Table 34: Forecast Public Lighting Unsmoothed Revenue

$M Real $2020	2020-21	2021-22	2022-23	2023-24	2024-25
Conventional	24.16	22.79	21.14	19.28	17.21
LED	1.15	2.54	4.25	6.35	8.86
Total	**25.31**	**25.33**	**25.39**	**25.63**	**26.06**

Figure 14 details the trend in our total public lighting revenue over the 2015-20 and 2020-25 regulatory control periods.

Figure 14 Public Lighting Unsmoothed Revenue



In its Draft Decision the AER published several discussion points from public lighting customers. We subsequentially undertook further engagement where we:

- Clarified that the current public lighting regulatory asset base covered both NPL1 and NPL2 tariff categories, representing the current depreciated value of the portfolio of assets. This value is based on the cost of the assets borne by us and therefore does not include gifted assts. It is limited to public lighting infrastructure and specifically excludes shared infrastructure.
- Demonstrated the benefit to customers when assets continue to be utilised beyond their expected lives, as it became apparent that this element of the regulatory model was not well understood. As each tariff includes the *return on* and *return of* capital of the underlying regulated asset base, fully depreciated assets do not add to the revenue requirement but do add to the number of assets the required revenue is allocated across. In this way, fully

depreciated assets that continue to operate reduce the tariff for all customers in the tariff category.

- Clarified that once assigned, assets would remain in the same tariff category.

11.4 Metering services

Under the Australian Energy Market Commission's (AEMC) Power of Choice (POC), the provision of new and replacement meters is fully contestable and is facilitated by retailers on behalf of customers. We no longer install new or replacement meters in the areas of covered by the National Electricity Rules (NER).

We continue to provide Type 6 legacy metering services (i.e. the maintenance, reading and data services associated with the legacy meters) and to recover the capital cost of metering equipment installed prior to the POC reforms.

For this Revised Regulatory Proposal, we continue to use a limited building block approach to determine the revenue requirement for these metering services, incorporating the following changes:

- The building block revenue requirement has been updated to reflect the WACC used in the SCS building block.
- We have removed the capitalise non-network costs from the metering asset base to comply with the AER's treatment of non-network expenditure in the Draft Decision. This capitalise non-network costs are now treated as an expense in our opex. This has resulted in a material increase in opex for the 2020-25 regulatory period.
- In accepting the AER's proposed approach to cap overheads at 35% of total opex we needed to correct the allocation of some expenses from overheads to opex.

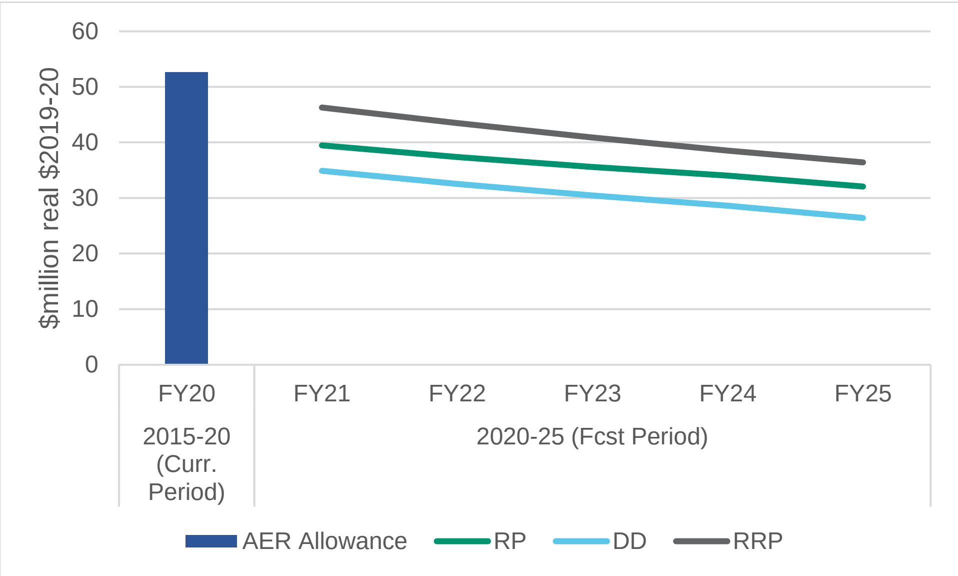
Table 35 Forecast Metering Services Unsmoothed Revenue

$million nominal	2020-21	2021-22	2022-23	2023-24	2024-25
Metering Revenue	47.38	45.55	43.88	42.34	40.94

The proposed metering revenue in our revised regulatory proposal remains significantly below current levels as shown in

Figure 15.

Figure 15 Metering Revenue



11.5 Ancillary (fee-based and quoted) services

We have revised our fee-based and quoted services and updated our models to reflect the AER's approach and utilise the latest information including our assumptions for labour escalations.

In its Draft Decision the AER questioned the role of Paraprofessionals, as this is a work category not covered by its consultant. Paraprofessionals undertake the assessment of technical information such as customer load, equipment operation and technical specifications, and network capacity in response to customer requests for connection (among other tasks). Their responsibilities extend to the determination of whether a customer can connect at that location or whether works or upgrades are required to our network to accommodate the connection.

The AER also challenged the rate used for Administration staff. We have upskilled Administration staff with an understanding and ability to use our standard tools to undertake a level of assessment on the more straightforward connection applications. Administration staff have received training to be able to process and assess the complexity of applications, enabling them to directly approve applications where it can be easily identified that the customer load requirements and the existing network will support the connection. This limits the workload of our Paraprofessionals to the applications that require more detailed assessments.

11.6 Security lights

Security lighting services involve installation, operation, maintenance and replacement of lighting equipment which is typically mounted to our distribution network poles and structures. These services are currently provided by us to 527 customers as an unregulated service. Our customers include small businesses, local government and State government authorities, schools and not-for-profit organisations.

For the 2020-25 regulatory control period the prices for security lighting services will be regulated by the AER. This change in service classification avoids the need to have security lighting service ring-fenced from Ergon Energy's regulated distribution network services.

The AER endorsed our proposed approach that security lighting services will be installed on a quotation basis, with a fee basis for ongoing maintenance, operation and replacement costs, as well as for electricity usage. The on-going maintenance, operation, replacement and energy use charges vary depending on the level of illumination requested by the customer. We have provided fees for these services in our Revised Tariff Structure Statement.

The proposed one-off installation charge is designed to recover the opex associated with the installation of new security lighting.

We have used a bottom up methodology to determine the revenue requirement for the operation, maintenance and replacement costs for security lights. The proposed fee-based charges are designed to recover both the capital and non-capital components, with the capital costs being recovered during the life of the lighting equipment. We have incorporated inputs (WACC, labour escalation and CPI) which are consistent with the AER's Draft Decision.

Table 36 Security lights

Number of lights (June 2019)	527
Forecast operation, maintenance and replacement revenue for 2019-20	$611,727

Note: the forecast revenue excludes energy use charges

11.7 Supporting information

The following documents supporting this chapter accompany our Revised Regulatory Proposal:

Name	Ref	File name
ACS metering pricing model	11.001	EGX ERG 11.001 ACS metering pricing model DEC19 PUBLIC
Fee-based and quoted services model – ACS	11.002	EGX ERG 11.002 Fee-based and quoted services model – ACS DEC19 PUBLIC
ACS Public lighting LED and Conventional Pricing model	11.003	ERG 11.003 ACS Public lighting LED and Conventional Pricing model DEC19 PUBLIC
Capex forecast – ACS public lighting CON	11.004	ERG 11.004 Capex forecast – ACS public lighting CON DEC19 PUBLIC
Capex forecast – ACS public lighting LED	11.005	ERG 11.005 Capex forecast – ACS public lighting LED DEC19 PUBLIC
Capex forecast – ACS metering	11.006	ERG 11.006 Capex forecast – ACS metering DEC19 PUBLIC
Opex forecast – ACS metering	11.007	ERG 11.007 Opex forecast – ACS metering DEC19 PUBLIC
Opex forecast – ACS public lighting	11.008	ERG 11.008 Opex forecast – ACS public lighting DEC19 PUBLIC
PTRM – ACS public lighting LED	11.009	ERG 11.009 PTRM – ACS public lighting LED DEC19 PUBLIC
PTRM – ACS public lighting CON	11.010	ERG 11.010 PTRM – ACS public lighting CON DEC19 PUBLIC
PTRM – ACS metering	11.011	ERG 11.011 PTRM – ACS metering DEC19 PUBLIC
RFM – ACS metering	11.012	ERG 11.012 RFM – ACS metering DEC19 PUBLIC
RFM – ACS public lighting	11.013	ERG 11.013 RFM – ACS public lighting DEC19 PUBLIC
RFM – ACS public lighting	11.014	ERG 11.014 Security Lighting Pricing Model - ACS DEC19 PUBLIC
Public Lighting Supporting Material	11.015	EGX ERG 11.015 Public Lighting Supporting Material DEC19 PUBLIC

12. Appendices and attachments

Glossary of terms

Acronym/Abbreviation	Meaning
$ nominal	These are nominal dollars of the day
real $2019-20	These are dollar terms as at 30 June 2020
2020-25 regulatory control period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
ACCC	Australian Competition and Consumer Commission
ACS	Alternative Control Service
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
ATO	Australian Tax Office
augex	Augmentation expenditure
CAM	Cost allocation method
capex	Capital expenditure
CBD	Central business district
CCP	Consumer Challenge Panel
CESS	Capital efficiency sharing scheme
connex	Connection expenditure
CPI	Consumer Price Index
Current regulatory control period or current period	Regulatory control period 1 July 2015 to 30 June 2020
DER	Distributed energy resources
distributor	Distribution Network Service Provider
DMIA	Demand management incentive allowance
DMIAM	Demand management innovation allowance mechanism
DMIS	Demand Management Incentive Scheme
DUOS	Distribution Use of System
EBSS	Efficiency benefits sharing scheme
ECA	Energy Consumers Australia
Ergon Energy	Ergon Energy Corporation Limited
ERP	Equity Risk Premium
F&A	Framework and Approach
GSL	Guaranteed service level
GSP	Gross State Product
GWH	gigawatt hours
HV	High voltage
ICT	Information and Communication Technologies
LED	Light emitting diode
LRMC	Long Run Marginal Cost
LV	Low voltage
MW	megawatt
MYFER	Mid-year fiscal and economic review

Acronym/Abbreviation	Meaning
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electricity Rules (or Rules)
Next regulatory control period or forecast period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
NMI	National Metering Identifier
Opex	Operating and Maintenance Expenditure
PLAB	Public lighting asset base
POC	Power of Choice
POE	Probability of exceedance
Previous regulatory control period or previous period	Regulatory control period 1 July 2010 to 30 June 2015
PTRM	Post-tax revenue model
PV	Photovoltaic (Solar PV)
QCA	Queensland Competition Authority
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
Regulatory Proposal	Energex or Ergon Energy's proposal for the next regulatory control period submitted under clause 6.8 of the NER
Repex	Replacement capital expenditure
Revised Regulatory Proposal	Energex or Ergon Energy's revised proposal for the next regulatory control period submitted under clause 6.10.3 of the NER
RFM	Roll forward model
RIN	Regulatory Information Notice
SAIDI	System average interruption duration index
SAIFI	System Average Interruption Frequency Index
SCS	Standard Control Service
SPARQ	SPARQ Solutions
STPIS	Service target performance incentive scheme
TSS	Tariff Structure Statement
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital (also known as Rate of Return)