Reset RIN Schedule 1 response

31 January 2019

1. Introduction

The purpose of this document is to identify where Ergon Energy Corporation Limited (Ergon Energy) has addressed each requirement of Schedule 1 of the reset Regulatory Information Notice (RIN) issued on 31 October 2018.

Table 1 in Section 2 of this document identifies the Schedule 1 requirement and Ergon Energy's response. The majority of responses are addressed in documents submitted to the Australian Energy Regulator (AER) in support of Ergon Energy's Regulatory Proposal. In these cases, the response provided refers to a document or model in our document register. In other cases, Ergon Energy has directly responded to the relevant Schedule 1 requirement in the table without further references. Where the Schedule 1 requirement does not directly seek a response, the relevant rows have been greyed out in Table 1.

Section 3 of this document provides a description of each material assumption as required by clause 1.5 of Schedule 1 of the RIN.

2. Table of responses to Schedule 1

Table 1: Response to Schedule 1 requirements

RIN Reference	Requirement	Response / Cross reference to material provided by Ergon Energy
1	**PROVIDE INFORMATION**	
1.1	Provide the information required in each regulatory template in the Microsoft Excel Workbook 1 – Regulatory determination, Workbook 2 – New category analysis, Workbook 5 - EBSS and Workbook 7 - Indicative Bill Impact, completed in accordance with:	Ergon Energy has provided the information required in each of the regulatory templates in the following documents: • 2020-25 Regulatory Determination RIN template (Attachment 17.053) • 2020-25 New Historical Category Analysis RIN template (Attachment 17.054) • 2020-25 Efficiency Benefit Sharing Scheme RIN template (Attachment 17.057) • 2020-25 Capital Expenditure Sharing Scheme RIN template (Attachment 17.058), and • 2020-25 Indicative Bill Impact RIN template (Attachment 17.059).
1.1(a)	this notice;	Refer to response 1.1 noting that Ergon Energy has provided information in regulatory templates of the specified workbooks attached at Appendix A to the RIN. The information provided has been prepared in accordance with the AER’s RIN.
1.1(b)	the instructions in the relevant Microsoft Excel Workbook attached at Appendix A;	Refer to response 1.1 noting that Ergon Energy has provided information in regulatory templates of the specified workbooks attached at Appendix A to the RIN. The information provided has been prepared in accordance with instructions in the relevant workbook and/or template.
1.1(c)	the instructions in Appendix E;	Refer to response 1.1 noting that Ergon Energy has provided information in regulatory templates of the specified workbooks attached at Appendix A to the RIN.

		The information provided has been prepared in accordance with relevant instructions in Appendix E.
1.1(d)	the service classifications set out in the framework and approach paper; and	Refer to response 1.1 noting that Ergon Energy has provided information in regulatory templates of the specified workbooks attached at Appendix A to the RIN. The information provided has been completed in accordance with the AER's proposed service classifications as set out in the final Framework and Approach paper dated July 2018. Refer to https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/Ergon Energy-determination-2020-25/aer-position
1.1(e)	Ergon Energy's cost allocation method.	Refer to response 1.1 noting that Ergon Energy has provided information as required in the regulatory templates of the specified workbooks attached at Appendix A to the RIN. The information provided has been completed in accordance with the Cost Allocation Method (CAM) approved by the AER on 22 November 2018. Refer to Attachment 6.004.
1.1A	Provide the information required in each regulatory template in the Microsoft Excel Workbook 5 – EBSS, and Workbook 6 – CESS, completed in accordance with:	Ergon Energy has provided information required in each of the regulatory templates in the following documents: • 2020-25 Efficiency Benefit Sharing Scheme RIN template (Attachment 17.057), and • 2020-25 Capital Expenditure Sharing Scheme RIN template (Attachment 17.058).
1.1A(a)	this notice;	Refer to response 1.1A noting that Ergon Energy has provided information in regulatory templates of the specified workbooks. The information provided has been prepared in accordance with the AER's RIN.
1.1A(b)	the instructions in the relevant Microsoft Excel Workbook attached at Appendix A;	Refer to response 1.1A noting that noting that Ergon Energy has provided information in regulatory templates of the specified workbooks. The information provided has been prepared in accordance with the AER's instructions in the relevant Microsoft Excel Workbook attached at Appendix A.

1.1A(c)	the instructions in Appendix E;	Refer to response 1.1A noting that Ergon Energy has provided information in regulatory templates of the specified workbooks. The information provided has been prepared in accordance with the AER's instructions in Appendix E.
1.1A(d)	the service classifications that applied in each regulatory year; and	Refer to response 1.1A noting that Ergon Energy has provided information in regulatory templates of the specified workbooks. The information provided has been prepared in accordance with the service classifications that applied in each regulatory year.
1.1A(e)	Ergon Energy's cost allocation method that applied in each regulatory year.	Refer to response 1.1A noting that Ergon Energy has provided information in regulatory templates of the specified workbooks. The information provided has been prepared in accordance with the CAM that applied in each regulatory year.
1.2	If:	
1.2(a)	Ergon Energy's cost allocation method has changed during the current regulatory control period, or	A revised CAM applicable for the period 1 July 2018 to 30 June 2020 was approved by the AER on 22 November 2018. The change was to give effect to the updated organisational structure.
1.2(b)	Ergon Energy's service classifications have changed from the current regulatory control period, or	There have been some service classification changes from the current regulatory control period. The materiality (or otherwise) of the impacts of these changes is discussed in the Basis of Preparation for recast information (refer to response 1.3).
1.2(c)	Ergon Energy proposes to divert from the service classifications set out in the relevant framework and approach paper, or	Ergon Energy has largely retained the service classifications as set out in the final Framework and Approach paper dated July 2018, but applied the service groupings and descriptions set out in the AER's Service Classification Guideline published in September 2018. Refer to Chapter 4 of the Regulatory Proposal and Attachment 4.004.
1.2(d)	Ergon Energy proposes to change its cost allocation method for the forthcoming regulatory control period;	Ergon Energy's CAM for the forthcoming regulatory control period was approved by the AER on 22 November 2018. A number of changes have occurred with the application of the new CAM for the forthcoming regulatory control period. The materiality (or otherwise) of the impacts of these changes is discussed in the Basis

		of Preparation for recast information (refer to response 1.3).
1.2	such that there would be material changes to information previously submitted to the AER Ergon Energy must use the regulatory templates in Workbook 3 – Recast category analysis and Workbook 4 – Recast economic benchmarking attached at Appendix A to submit revised historical information.	Refer to response 1.2(b) and 1.2(d) – as a result of changes to the Classification of Services and CAM applicable in the forthcoming regulatory control period Ergon Energy has identified some material changes to information previously submitted to the AER. Accordingly, Ergon Energy has provided revised historical information in the regulatory templates of the specified workbooks in the following documents: • 2020-25 Recast Category Analysis RIN template (Attachment 17.055), and • 2020-25 Recast Economic Benchmarking RIN template (Attachment 17.056). A Basis of Preparation has been provided relative to any recast information provided in the templates for these workbooks (refer response to 1.3).
1.3	For all information, other than forecast information, provide in accordance with this notice and the instructions in Appendix E, a basis of preparation demonstrating how Ergon Energy has complied with this notice in respect of:	Ergon Energy has provided a Basis of Preparation for all information other than forecast information in accordance with this notice and the instructions in Appendix E, as found in the following documents: • Basis of Preparation - Regulatory Determination (Attachment 17.012) • Basis of Preparation - New Historical Category Analysis (Attachment 17.013) • Basis of Preparation - Recast Category Analysis (Attachment 17.014) • Basis of Preparation - Recast Economic Benchmarking (Attachment 17.015) • Basis of Preparation - EBSS (Attachment 17.016) • Basis of Preparation - CESS (Attachment 17.017), and • Other attachments to Schedule 1, referenced in the relevant responses.
1.3(a)	the information in each regulatory template in the Microsoft Excel Workbooks attached at Appendix A; and	Refer response to 1.3. Ergon Energy has provided a Basis of Preparation in relation to all historical information contained in regulatory templates within the Microsoft Excel Workbooks attached at Appendix A to the AER's RIN.

1.3(b)	the information prepared in accordance with the following requirements in Schedule 1 of this notice:	
1.3(b)(i)	paragraph 1.2	Refer to response 1.3, noting Ergon Energy has provided a Basis of Preparation in relation to requirements in Schedule 1 Paragraph 1.2 of the AER's RIN. The information is in the 2020-25 Recast Category Analysis RIN template (Attachment 17.055), and the 2020-25 Recast Economic Benchmarking RIN template (Attachment 17.056).
1.3(b)(ii)	paragraph 5.1(a)(ii)	Refer to the 'Repex Model Supporting Information' document (Attachment 17.029).
1.3(b)(iii)	paragraph 8.5	Refer to the 'Demand Management Regulatory Proposal (2020-2025) document (Attachment 7.051) Appendix One.
1.3(b)(iv)	paragraph 13 (13.5 and 13.6)	Refer to responses provided in paragraph 13.5 and paragraph 13.6, including supporting information provided in relation to paragraph 13, Alternative Control Services.
1.3(b)(v)	paragraph 15 (15.2 and 15.3)	Refer to responses provided in paragraphs 15.2 and 15.3.
1.3(b)(vi)	paragraph 16 (16.2-16.7, 16.10)	Refer to responses provided in paragraphs 16.2- 16.7 and 16.10.
1.4	Provide material used for the purposes of preparing the regulatory proposal:	
1.4(a)	all consultants' reports commissioned and relied upon in whole or in part;	Where Ergon Energy has relied upon consultant reports these have been identified in the 'Document Register' (Attachment 1.008). Where the author of document is a consultant, this has been made clear in the file name as required.
1.4(b)	all material assumptions relied upon;	Material assumptions relied upon by Ergon Energy the purposes of preparing the regulatory proposal have been disclosed in Section 3 of this document.
1.4(c)	a table that references each response to a paragraph in this Schedule 1 and where it is provided in or as part of the regulatory	This table has been designed to provide the AER with the information in the form

	proposal;	required.
1.4(d)	a table that references each document provided in or as part of the regulatory proposal and its relationship to other documents provided; and	Refer to ‘Document Register’ (Attachment 1.0085) which references each document provided by Ergon Energy in or as part of the Regulatory Proposal and its relationship to other documents provided.
1.4(e)	each document identified in paragraph 1.4(d) must be given a meaningful filename in the form: Ergon Energy– [Author] – [title] – [date] – [public/confidential], where:	Refer to response 1.4(d) - each document referenced has been given a meaningful filename in accordance with instructions in the AER’s RIN.
1.4(e)(i)	**Author** is the author of the file if not Ergon Energy, for example a consultant or other third party;	Refer to response 1.4(d) - each document referenced has been given a filename which notes where the author is a consultant or third party, in accordance with instructions in the AER’s RIN. Of note, where the author is Ergon Energy this has not been repeated twice in the title.
1.4(e)(ii)	**Title** provides a meaningful description of the content of document, with limited reliance on acronyms or cross references, for example “Appendix 1A” is not meaningful, but “Appendix 1A – Cost allocation method” is;	Refer response to 1.4(d) - each document referenced has been given a title in accordance with instructions in the AER’s RIN.
1.4(e)(iii)	**Date** is a relevant date associated with the file, generally the date the document was created;	Refer to response 1.4(d) - each document referenced has been given a creation date in accordance with instructions in the AER’s RIN.
1.4(e)(iv)	**Public/confidential** identifies if the file in its entirety can be published (public); or if it contains any information which is the subject of a claim for confidentiality in accordance with paragraph 32 of this notice (confidential).	Refer to response 1.4(d) - each document referenced has been given a filename in accordance with instructions in the AER’s RIN, which makes clear whether the file is public or confidential in nature. Refer also to responses 34.3 and 35.1 relating to Confidential Information.
1.5	Provide for each material assumption identified in the response to paragraph 1.4(b):	
1.5(a)	its source or basis;	Refer to response 1.4(b) – the source or basis of each material assumptions relied upon for the purposes of preparing the regulatory proposal has been disclosed in

		Section 3 of this document.
1.5(b)	if applicable, its quantum;	Refer to response 1.4(b) – if applicable, the quantum of each material assumption relied upon has been disclosed in Section 3 of this document.
1.5(c)	whether and how the assumption has been applied and was taken into account; and	Refer to response 1.4(b) – whether and how each material assumption has been applied and was taken into account by the Ergon Energy has been disclosed in Section 3 of this document.
1.5(d)	the effect or impact of the assumption on the capital and operating expenditure forecasts in the forthcoming regulatory control period taking into account:	
1.5(d)(i)	the actual expenditure incurred during the current regulatory control period; and	Refer to response 1.4(b) and Section 3 of this document.
1.5(d)(ii)	the sensitivity of the forecast expenditure to the assumption.	Refer to response 1.4(b) and Section 3 of this document.
1.6	Provide reconciliation of the capital and operating expenditure forecasts provided in the regulatory templates to the proposed capital and operating allowances in the post-tax revenue model for the forthcoming regulatory control period.	Capital and operating expenditure forecasts provided in the regulatory templates have been reconciled to the information in the post-tax revenue model (PTRM) in the model in the “Reset RIN Population Model” (Attachment 17.066).
1.7	Where the regulatory proposal varies or departs from the application of any component or parameter of the capital efficiency sharing scheme, efficiency benefit sharing scheme, demand management incentive scheme or service target performance incentive scheme as set out in the framework and approach paper, for each variation or departure explain:	
1.7(a)	the reasons for the variation or departure, including why it is appropriate;	Refer to Chapters 4 and 11 of Ergon Energy’s Regulatory Proposal. Ergon Energy has not proposed any variations or departures to the AER’s application of incentive schemes as set out in the final Framework and Approach paper dated July 2018.

1.7(b)	how the variation or departure aligns with the objectives of the relevant scheme; and	Refer to response 1.7(a). Ergon Energy has not proposed any variations or departures to the AER's application of incentive schemes as set out in the final Framework and Approach.
1.7(c)	how the proposed variation or departure will impact the operation of the relevant scheme.	Refer to response 1.7(a). Ergon Energy has not proposed any variations or departures to the AER's application of incentive schemes as set out in the final Framework and Approach.
2	**CLASSIFICATION OF SERVICES**	
2.1	Identify each proposed service classification in the regulatory proposal which departs from a service classification set out in the framework and approach paper and explain:	Refer to Chapter 4 of Ergon Energy's Regulatory Proposal. Ergon Energy has largely retained the service classifications as set out in the final Framework and Approach paper dated July 2018, but applied the service groupings and descriptions set out in the AER's Service Classification Guideline published in September 2018.
2.1(a)	the reasons for the departure, including why the proposed service classification is more appropriate; and	Refer to response 2.1. Ergon Energy has largely retained the service classifications as set out in the final Framework and Approach paper dated July 2018, but applied the service groupings and descriptions set out in the AER's Service Classification Guideline published in September 2018.
2.1(b)	how the treatment of the service will differ under the proposed service classification in comparison to that in the framework and approach paper.	Refer to response 2.1. Ergon Energy has largely retained the service classifications as set out in the final Framework and Approach paper dated July 2018, but applied the service groupings and descriptions set out in the AER's Service Classification Guideline published in September 2018.
2.2	If the proposed service classifications in the regulatory proposal depart from any of the service classifications set out in the framework and approach paper:	
2.2(a)	provide, in a second set of regulatory templates, all information required in each regulatory template in accordance with the instructions contained therein, modified as necessary, to	Refer to response 2.1. Ergon Energy has largely retained the service classifications as set out in the final Framework and Approach paper dated July 2018, but applied the service groupings and descriptions set out in the AER's

	incorporate the proposed service classifications; and	Service Classification Guideline published in September 2018.
2.2(b)	identify and explain where the regulatory templates differ.	Refer to response to 2.1. Ergon Energy has largely retained the service classifications as set out in the final Framework and Approach paper dated July 2018, but applied the service groupings and descriptions set out in the AER's Service Classification Guideline published in September 2018.
3	**CONTROL MECHANISMS**	
3.1	For the forecast revenues that Ergon Energy proposes to recover from providing direct control services over the forthcoming regulatory control period provide:	
3.1(a)	formulaic expressions for the basis of control mechanisms for standard control services and for alternative control services; and	Ergon Energy has set out formulaic expressions for the basis of control mechanisms for standard control services (SCS) and for alternative control services (ACS) in the 'Control Mechanisms' document (Attachment 4.001).
3.1 (b)	a detailed explanation and justification for each component that makes up the formulaic expression.	Refer to 3.1(a). Ergon Energy has explained and justified each component of the formulae in the 'Control Mechanisms' document (Attachment 4.001).
3.2	Also demonstrate:	
3.2(a)	how Ergon Energy considers the control mechanisms are compliant with the framework and approach paper; and	Refer to the 'Control Mechanisms' document (Attachment 4.001),
3.2(b)	for standard control services, how Ergon Energy considers the control mechanisms are also compliant with clause 6.2.6 and Part C of Chapter 6 of the NER.	Refer to the 'Control Mechanisms' document (Attachment 4.001).
4	**CAPITAL EXPENDITURE**	
	General	
4.1	Provide justification for Ergon Energy total forecast capex,	

	including the following information:	
4.1(a)	why the total forecast capex is required for Ergon Energy to achieve each of the objectives in clause 6.5.7(a) of the NER;	Refer to Attachment 1.006 which provides a justification for how Ergon Energy's total forecast capital expenditure (capex) achieved the objectives in 6.5.7(a) of the National Electricity Rules (NER). Ergon Energy has built a bottom-up capex forecast which has been challenged by various top-down checks and modelling, business reviews, and customer feedback. The resultant capex forecast is an optimised portfolio balancing customer outcomes and performance, risk, and cost. For supporting details refer to Chapter 7 of our Regulatory Proposal and supporting information in our Asset Management Overview, Risk and Optimisation document (Attachment 7.026).
4.1(b)	how Ergon Energy's total forecast capex reasonably reflects each of the criteria in clause 6.5.7(c) of the NER;	Refer to Attachment 1.006 which provides a justification for how Ergon Energy's total forecast capex reasonably reflects each of the criteria in 6.5.7(c) of the NER. For further information refer to Chapter 7 of our Regulatory Proposal, specifically, section 7.5 which provides an overview of our expenditure forecasting methodology.
4.1(c)	how Ergon Energy's total forecast capex accounts for the factors in clause 6.5.7(e) of the NER;	Refer Attachment 1.006 which provides a justification for how Ergon Energy's total forecast capex accounts for the factors in 6.5.7(e) of the NER. For further information refer to Chapter 7 of our Regulatory Proposal.
4.1(d)	an explanation of how the plans, policies, procedures and regulatory obligations or requirements identified in Workbook 1 – regulatory determination, regulatory templates 7.1 and 7.3 have been used to develop forecast capex; and	Energex's Expenditure Forecasting Methodology (Attachment 4.002) provides a summary of the methodology used to develop our forecast capex. Ergon Energy's Asset Management System is underpinned by our Asset Management Policy - Attachment 7.045 and Strategic Asset Management Plans - Attachments 7.002, 7.090 and 7.144, which also outlines the decision making framework. Supporting this are: • Asset Management Plans (supporting attachments 7.027 through to 7.044)

		• Network Strategies (supporting attachments 7.047, 7.048, 7.080, and 7.089), and • Strategic Proposals and Business Cases (supporting attachments 7.055, 7.092, 7.093, 7.095, 7.096, 7.098, 7.099, 7.008-7.025 and 7.137-7.142). The Asset Management Risk and Optimisation document (Attachment 7.026) provides an overview of how the forecast network capex program is developed and administered. Other policies, strategies and procedures referenced in Reset RIN templates 7.1 and 7.3 that support achievement of the asset management objectives and customer service levels are available upon request.
4.1(e)	an explanation of how each response provided to paragraph 4.1 (a)-(d) is reflected in any increase or decrease in expenditures or volumes, particularly between the current and forthcoming regulatory control periods, provided in Workbook 1 – regulatory determination, regulatory templates 2.1 to 2.11.	The changes in Ergon Energy's capital expenditure between the current and forthcoming period are explained in Chapter 7 of our Regulatory Proposal.
4.2	Provide the model(s) and methodology Ergon Energy used to develop its total forecast capex, including:	Ergon Energy's Forecasting Methodology is set out in Attachment 4.002. Ergon Energy has also provided: • Capex forecast – SCS model (Attachment 7.154) • Capex forecast – ACS Metering model (Attachment 15.008) • Capex forecast – ACS Public lighting conventional (Attachment 15.032), and • Capex forecast – ACS Public lighting LED (Attachment 15.034). Further details of Ergon Energy's forecasting methodology for capex has also been outlined in Chapter 7 of our Regulatory Proposal.
4.2(a)	A description of how Ergon Energy prepared the forecast capex, including:	
4.2(a)(i)	how its preparation differed or related to budgetary, planning and	Ergon Energy has made significant improvements in recent years towards implementing a risk-based approach to asset management and optimisation of the

	governance processes used in the normal operation of Ergon Energy's business;	programs of work. These improvements have aided and informed the preparation of the capital expenditure forecast, with Ergon Energy developing a seven year program of work, and undertaking detailed examination and challenge of the proposed program as part of the optimisation process. For further detail refer to the 'Asset Management overview, Risk & Optimisation Strategy' document (Attachment 7.026). Customer feedback also informed the optimised capex forecast with early consultation with customers and engagement on Ergon Energy's draft plan for the forthcoming regulatory period.
4.2(a)(ii)	the processes for ensuring amounts are free of error and other quality assurance steps; and	Considerable work was undertaken to build the bottom up program and optimised investment forecast to 2025, utilising a Program of Work governance process. Candidate work was identified grounded on a risk based approach and loaded into the corporate portfolio, program and project management tools. Numerous iterations or scenarios on the composition of the overall program were considered and underwent staged review and top-down checks and challenge, together with management reviews to produce an optimised program for delivery. Ergon Energy's quality assurance process for data and models involved staged peer review, together with management review and sign-off.
4.2(a)(iii)	if and how Ergon Energy considered the resulting amounts, when translated into price impacts, were in the long-term interest of consumers.	Ergon Energy examined whether the proposed capital program is in the long-term interests of customers by engaging with customers to achieve a balance of our customer commitments; affordable, secure, and sustainable. Relevant factors such as price impact, safety outcomes and service quality were considered by customer groups in these engagement sessions. Customer feedback also informed the optimised capex forecast with early consultation with customers and engagement on Ergon Energy's draft plan for the forthcoming regulatory period. Further information may be found in the capital expenditure chapter of the regulatory proposal, and how the forecast capex differs from Our Draft Plans is outlined in the Overview of Our Regulatory Proposals.

4.2(b)	any source material used (including models, documentation or any other items containing quantitative data); and	Source material has been documented in: • Asset Management Plans (supporting attachments 7.027 • through to 7.045, and 7.090) • Network Strategies (supporting attachments 7.047, 7.048, 7.080, and 7.089) • Strategic Proposals and Business Cases (supporting attachments 7.055, 7.092, 7.093, 7.095, 7.096, 7.098, 7.099, 7.008-7.025 and 7.137-7.142), andUnit Cost Methodology and Estimation Approach (Attachment 7.005) The bottom up build of the capex program of work is represented in corporate portfolio, program and project management tools.
4.2(c)	calculations that demonstrate how data from the source material has been manipulated or transformed to generate data provided in the regulatory templates in Workbook 1 – Regulatory determination.	The calculations to transform source material can be found in the 'Reset RIN Population Model' (Attachment 17.066).
4.3	Identify which items of Ergon Energy's forecast capex are:	
4.3(a)	derived directly from competitive tender processes;	Our cost estimates for projects in our forecast capex are not derived directly from competitive tender processes. However, our cost estimation methodologies rely on historical experience with delivering projects and programs of a similar scope.
4.3(b)	based upon competitive tender processes for similar projects;	When developing our cost estimates for proposed capital projects we have considered the historical cost of completing projects of a similar nature, including where an external party has delivered the project under a competitive tender process. In particular, our unit cost estimates for building new zone substations has relied (to a degree) on actual costs of external parties that have tendered for the project under either competitive tender, or through a panel arrangement.
4.3(c)	based upon estimates obtained from contractors or manufacturers;	For major projects we have used a bottom up approach to estimate costs, which includes consideration of contractor and manufacturer estimates in the past. We note that we have panel arrangements in place under our procurement processes,

		and continually test the market.
4.3(d)	based upon independent benchmarks;	Ergon Energy does not develop a capex forecast based on external benchmarks costs. Our cost estimation approach is focused on developing estimates to deliver a scope of work. These costs have been tested
4.3(e)	based upon actual historical costs for similar projects; and	We have used averages of historical costs to determine the forecast unit rates for volume driven work including smaller projects and for “pooled” programs such as our pole replacement program.
4.3(f)	reflective of any amounts for risk, uncertainty or other unspecified contingency factors, and if so, how these amounts were calculated and deemed reasonable and prudent.	The Standard Control Service System (network) capital expenditure portfolio is developed and approved excluding consideration of project risk estimates or uncertainty. We have no unspecified contingency factors.
4.4	Provide all documents which were materially relied upon and relate to the deliverability of forecast capex and explain the proposed deliverability.	We have not relied on any specific documents to show that the forecast capex can be delivered. However, we note that Ergon Energy is well placed to deliver the proposed capital program. This is demonstrated by our delivery of a capital program in the current period that is higher than our forecast for the next period.
	Capex categories	
4.5	Describe each capex category and expenditures comprising these categories identified in the regulatory templates, including:	Refer to Chapter 7 of our Regulatory Proposal and the Expenditure Forecasting Method (Attachment 4.002) which provide general descriptions and definitions of each capex category in the regulatory templates.
4.5(a)	key drivers for expenditure;	Refer to Chapter 7 of the Regulatory Proposal and the Expenditure Forecasting Method (Attachment 4.002) which describe the key drivers of expenditure for each AER capex categories.
4.5(b)	an explanation of how expenditure is distinguished between:	
4.5(b)(i)	greenfield driven and reinforcement driven augmentation capex;	Ergon Energy’s augmentation capex solutions to identified constraints may either be the construction of new electrical assets where they don’t currently exist, which

		we interpret as “greenfield”, or increasing the capacity of existing assets, which Ergon Energy interprets as “reinforcement”. This is consistent with Reset RIN 2.3(b) categorisation.
4.5(b)(ii)	connections expenditure and augmentation capex;	Connections capex is required to service new, altered or upgraded connections for residential, commercial and industrial customers at their request. In contrast, a component of augmentation capex is driven by forecast network constraints, caused by population growth, specific development or load increases within localised parts of our distribution network, or growth in peak demand. The distinction is addressed in Chapter 7 of our Regulatory Proposal.
4.5(b)(iii)	replacement capex driven by condition and asset replacements driven by other drivers (e.g. the need for greenfield and reinforcement driven augmentation capex); and	Refer to Chapter 7 of our Regulatory Proposal.
4.5(b)(iv)	any other capex category or opex category where Ergon Energy considers that there is reasonable scope for ambiguity in categorisation.	The Low Voltage Network Safety program has been categorised and forecast by Ergon Energy as replacement expenditure as there is an interaction with the traditional like-for-like asset replacement of overhead low voltage services. Refer to Chapter 7 of the Regulatory Proposal for a description of the drivers of this program, and the LV Network Safety strategic proposal (Attachment 7.093) for detail. Ergon Energy has not identified any other ambiguities.
5	**REPLACEMENT CAPITAL EXPENDITURE MODELLING**	
5.1	In relation to information provided in Workbook 1 – Regulatory determination, regulatory template 2.2 and with respect to the AER’s repex model, provide:	
5.1(a)	For individual asset categories set out in the regulatory templates, provide in a separate document:	
5.1(a)(i)	a description of the asset category, including:	The description of individual asset categories relating to template 2.2 can be found

		in the 'Repex Model Supporting Information' document (Attachment 17.029). Ergon Energy has used the same definitions for forecast information in completing template 2.2 of "Workbook 1 - Regulatory Determination" (Attachment 17.053 - 2020-25 Regulatory Determination RIN template).
5.1(a)(i)(A)	the assets included and any boundary issues (i.e. with other asset categories);	Boundary issues have been discussed in Ergon Energy's description of template 2.2 in the 'Repex Model Supporting Information' document (Attachment 17.029) section 2.1.1.
5.1(a)(i)(B)	an explanation of how these matters have been accounted for in determining quantities in the age profile;	In general, boundary issues have not impacted the quantities in the age profiles. Refer to the 'Repex Model Supporting Information' document (Attachment 17.029) section 2.1.2. An exception relates to overhead conductor age which is calculated based on pole age.
5.1(a)(i)(C)	an explanation of the main drivers for replacement (e.g. condition); and	Please refer to Chapter 7 of our Regulatory Proposal for a description of the overarching drivers for replacement. Ergon Energy's Asset Management Plans provide further detail on our main drivers of replacement by asset category (Attachments 7.027 to 7.044).
5.1(a)(i)(D)	an explanation of whether the replacement unit cost provides for a complete replacement of the asset, or some other activity, including an extension of the asset's life (e.g. pole staking) and whether the costs of this extension or other activity are capitalised or not.	In general, Ergon Energy's cost estimate relates to the complete replacement of the asset. An exception relates to the staking of wooden poles which provides a life extension and is capitalised.
5.1(a)(ii)	an estimate of the proportion of assets replaced for each year of the current regulatory control period, due to:	
5.1(a)(ii)(A)	aging of existing assets (e.g. condition, obsolesce, etc.) that should be largely captured by this form of replacement modelling;	Refer to the 'Repex Model Supporting Information' document (Attachment 17.029), section 2.2.1.
5.1(a)(ii)(B)	replacements due to other factors (and a description of those factors);	Refer to the 'Repex Model Supporting Information' document (Attachment 17.029), section 2.2.2. Ergon Energy's Asset Management Plans provide further detail on the main drivers

		of replacement by asset category (Attachments 7.027 to 7.044).
5.1(a)(ii)(C)	additional assets due to the augmentation, extension, development of the network; and	Refer to the 'Repex Model Supporting Information' document (Attachment 17.029), section 2.2.3.
5.1(a)(ii)(D)	additional assets due to other factors (and a description of those factors).	In replacing assets, Ergon Energy is likely to use different technology and modern equipment relative to the original design of the asset being replaced. However, the asset would still perform the same function. In some cases, Ergon Energy's network standards may require a different standard or design compared to the asset being replaced. Refer to response to 4.5(b)(iv) whereby the LV Network Safety strategic proposal discusses introduction of additional assets to address safety risks as well as enable life extension of existing assets.
5.1(b)	For the previous, current and forthcoming regulatory control periods, explain the drivers or factors that have changed network replacement expenditure requirements. Identify and quantify the relative effect of individual matters within the following categories:	
5.1(b)(i)	rules, codes, licence conditions, statutory requirements;	Refer to Chapter 7 of our Regulatory Proposal for a description of the drivers and factors that have impacted capex (including network replacement expenditure requirements). Replacement capital expenditure has also been sub-categorised within the capex chapter of the regulatory proposal as follows: Condition and risk – proactive replacement of high risk assets which have been identified as approaching the end of their lifecycle. Reactive – replacement projects and programs driven predominately by inspection and in-service failure.
5.1(b)(ii)	internal planning and asset management approaches;	Refer to the Chapter 7 of our Regulatory Proposal. Ergon Energy's Asset Management Plans provide further detail on the main drivers

		of replacement by asset category (Attachments 7.027 to 7.044).
5.1(b)(iii)	measurable asset factors that affect the need for expenditure in this category (e.g. age profiles, risk profiles, condition trend, etc.). Identify and quantify individual factors;	Ergon Energy's Asset Management Plans provide further detail on the main drivers of replacement by asset category (Attachments 7.027 to 7.044).
5.1(b)(iv)	the external factors that can be forecast and the outcome measured (e.g. demand growth, customer numbers) that affect the need for expenditure in this category. Identify and quantify individual factors, covering the forecasts and the outcome (external factors to be discussed here do not relate to changing obligations which are covered in paragraphs 11.3 and 11.8);	Refer to the Asset Management Plans which provide further detail on the factors influencing replacement (Attachments 7.027 to 7.044).
5.1(b)(v)	technology/solutions to address needs, covering:	
5.1(b)(v)(A)	network; and	Chapter 7 of the Regulatory Proposal notes that some of Ergon Energy's forecast replacement capex is driven by technical obsolescence, including where vendor or manufacturer support has been withdrawn and spares are exhausted. These issues particularly impact protection and control, and secondary systems assets where unavailability of support and/or spares can result in extended outages. Also refer to response to 4.5(b)(iv) whereby the LV Network Safety strategic proposal discusses use of technology to address safety risks as well as enable life extension of existing assets. Ergon Energy's Asset Management Plans also provide further detail on future technology considerations by asset category (Attachments 7.027 to 7.044).
5.1(b)(v)(B)	non-network.	Ergon Energy has not identified a specific non-network solution for replacement projects in the forthcoming period. Further information on Ergon Energy's approach to non-network solutions and demand management is found in the response to Question 8 of this table.
5.1(b)(vi)	any other significant matters.	Ergon Energy has not identified any other significant matters.

5.1(b)(vii)	Identify and provide information or documentation to justify and support any responses to paragraph 5.1(b) (i)-(vi).	Ergon Energy's document register includes the following documents relevant to the questions above: • Regulatory Proposal document, Chapter 7 – Capital Expenditure • Strategic Asset Management Plan (Attachment 7.090), and • Asset Management Plans (Attachments 7.027-7.044).
5.1(b)	The information provided in response to paragraph 5.1(b) above should at least distinguish between the asset categories listed in Workbook 1 – Regulatory determination, regulatory template 2.2.	
6	**AUGMENTATION CAPITAL EXPENDITURE MODELLING**	
6.1	Any instructions in this notice relating to the augex model must be read in conjunction with the augex model guidance document available on the AER's website (http://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/expenditure-forecast-assessment-guideline/final-decision).	
6.2	In relation to information provided in Workbook 1 – Regulatory determination, regulatory template 2.4 and with respect to the AER's augex model:	The AER has advised they do not require Ergon Energy to complete the regulatory template 2.4 of Workbook 1 – Regulatory Determination.
6.2(a)	Separately for sub-transmission lines, sub-transmission and zone substations, HV feeders and distribution substations, Ergon Energy must explain how it:	
6.2(a)(i)	Prepared the maximum demand data (weather corrected at 50 per cent probability of exceedance) provided in the asset status tables 2.4.1 to 2.4.4, including where relevant, explanations of each of:	
6.2(a)(i)(A)	how this value relates to the maximum demand that would be used for normal planning purposes;	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.

6.2(a)(i)(B)	whether it is based upon a measured value, and if so, where the measurement point is and how abnormal operating conditions are allowed for;	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(a)(i)(C)	whether it is based on estimated (rather than actual measured) demand, and if so, the basis of this estimation process and how it is validated; and	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(a)(i)(D)	the relationship of the values provided to raw unadjusted maximum demand; and the relationship of the values provided to the values that could be expected from weather corrected maximum demand measures that reflect a 10 per cent probability of exceedance year.	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(a)(ii)	Determined the rating data provided in the asset status tables 2.4.1 to 2.4.4, including where relevant:	
6.2(a)(ii)(A)	the basis of the calculation of the ratings in that segment, including asset data measured and assumptions made; and	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(a)(ii)(B)	the relationship of these ratings with Ergon Energy's approach to operating and planning the network. For example, if alternative ratings are used to determine the augmentation time, these should be defined and explained.	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(a)(iii)	Determined the growth rate data provided in the asset status tables 2.4.1 to 2.4.4. This should clearly indicate how these rates have been derived from maximum demand forecasts or other load forecasts available to Ergon Energy.	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(b)	In relation to the capex-capacity table 2.4.6, Ergon Energy must explain:	
6.2(b)(i)	the types of cost and activities covered. Clearly indicate what non-field analysis and management costs (i.e. direct overheads) are	Refer to response provided in 6.2, noting Ergon Energy is not required to submit

	included in the capex and what proportion of capex these cost types represent;	this information.
6.2(b)(ii)	how it determined and allocated actual capex and capacity to each of the segment groups, covering:	
6.2(b)(ii)(A)	the process used, including assumptions, to estimate and allocate expenditure where this has been required; and	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(b)(ii)(B)	the relationship of internal financial and/or project recording categories to the segment groups and process used.	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(b)(iii)	how it determined and allocated estimated/forecast capex and capacity to each of the segment groups, covering:	
6.2(b)(iii)(A)	the relationship of this process to the current project and program plans; and	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(b)(iii)B)	any other higher-level analysis and assumptions applied.	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(c)	Describe the projects and programs Ergon Energy has allocated to the unmodelled augmentation categories in table 2.4.6, covering:	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(c)(i)	the proportion of unmodelled augmentation capex due to this project or program type;	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(c)(ii)	the primary drivers of this capex, and whether in Ergon Energy's view, there is any secondary relationship to maximum demand and/or utilisation of the Ergon Energy network; and	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(d)	Separately for each network segment that Ergon Energy defined in the model segment data table 2.4.5, whether the outcome of such a project or program, whether intended or not, should be an	

	increase in the capability of the Ergon Energy network to supply customer demand at similar service levels, or the improvement in service levels for a similar customer demand level:	
6.2(d)(i)	Describe the network segment, including:	
6.2(d)(i)(A)	the boundary with other connecting network segments; and	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(d)(i)(B)	the main reasoning for the individual segment (e.g. as opposed to forming a more aggregate segment).	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(d)(ii)	Explain the utilisation threshold statistics provided (i.e. the mean and standard deviation), including:	
6.2(d)(ii)(A)	the methodology, data sources and assumptions used to derive the parameters;	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(d)(ii)(B)	the relationship to internal or external planning criteria that define when an augmentation is required;	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(d)(ii)(C)	the relationship to actual historical utilisation at the time that augmentations occurred for that asset category;	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(d)(ii)(D)	Ergon Energy views on the most appropriate probability distribution to simulate the augmentation needs of that network segment; and	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(d)(ii)(E)	the process applied to verify that the parameters are a reasonable estimate of utilisation limit for the network segment.	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(d)(iii)	Regarding the augmentation unit cost and capacity factor provided, provide an explanation of each of:	
6.2(d)(iii)(A)	the methodology, data sources and assumptions used to derive the	Refer to response provided in 6.2, noting Ergon Energy is not required to submit

	parameters;	this information.
6.2(d)(iii)(B)	the relationship of the parameters to actual historical augmentation projects, including the capacity added through those projects and the cost of those projects;	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(d)(iii)(C)	the possibility of double-counting in the estimates, and processes applied to ensure that this is appropriately accounted for (e.g. where an individual project may add capacity to various segments); and	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(d)(iii)(D)	the process applied to verify that the parameters are a reasonable estimate for the network segment.	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(e)	Explain the factors Ergon Energy considers may result in different augmentation requirements for itself as compared to other NEM-based DNSPs. Ergon Energy must account for the degree that different augmentation requirements are driven by differences in asset utilisation and maximum demand growth. Ergon Energy must also explain all other factors, specific to its network, which would result in different augmentation requirements when compared to a DNSP with similar asset utilisation and maximum demand growth. The explanation must clearly indicate those factors that may impact:	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(e)(i)	the maximum achievable utilisation of assets for Ergon Energy; and	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(e)(ii)	the likely augmentation project and/or cost.	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.
6.2(e)	For each significant factor discussed, Ergon Energy must indicate relevant model segments and estimate the impact these factors will have on its augmentation levels and associated capex compared to	Refer to response provided in 6.2, noting Ergon Energy is not required to submit this information.

	other DNSPs.	
7	**CONNECTIONS EXPENDITURE**	
7.1	Provide and describe the methodology and assumptions used to prepare the forecasts of connection works including:	
7.1(a)	Estimation of connection unit costs for each customer type; and	The unit cost per connection type was developed based on the 2017-18 actual aggregate cost per connection type divided by the number of connections per customer type. A base year unit rate (expressed in real 2018-19) was established by indexing the 2017 values to 2018-19 consistent with the assumptions that underlie the Regulatory Proposal.
7.1(b)	Connection volumes for each customer type.	The annual 'volume per connection type' is based on a combination of historical data and resource estimates from subject matter estimates. Refer to Chapter 7 of our Regulatory Proposal for further information.
7.2	Ergon Energy must provide its estimation of customer contributions based upon the estimated life and revenue to be recovered from connection assets, including:	Ergon Energy's estimation of customer contributions is provided in Chapter 7 of our Regulatory Proposal.
7.2(a)	the expected life of the connection;	Refer to the response provided in 7.2
7.2(b)	the average consumption expected by the customer over the life of the connection; and	Refer to the response provided in 7.2
7.2(c)	any other factors that influence the expected recovery of the Ergon Energy network use of system charge to customers.	Refer to the response provided in 7.2
8	**NON-NETWORK ALTERNATIVES**	
8.1	Identify the policies and strategies and procedures in the response to Workbook 1 – Regulatory determination, regulatory template 7.1 which relate to the selection of efficient non-network solutions.	Ergon Energy applies its Demand Management Plan 2018-19, which contains the strategy for demand management for the next seven years, refer to Attachment 6.001

		Demand Management is delivered as part of its business as usual planning processes. These policies, strategies and procedures are supported by internal procedures published in Process Zone. Relevant internal documents include: • NA0009 – Plan network investments • NA000904 – Conduct annual planning review, and • NA0009906 – Conduct regulatory investment test.
8.2	Explain the extent to which the provision for efficient non-network alternatives has been considered in the development of the forecast capex proposal and the forecast opex proposal.	There are several unique factors in Ergon Energy’s network that influenced how demand management solutions could be utilised to reduce capital and operating costs. The extent to which the provision for efficient non network alternatives has been considered in the development of the forecast capex and forecast operating expenditure (opex) proposal is explained in the Demand Management Regulatory Proposal (2020-2025) document (Attachment 7.051).
8.3	Identify each non-network alternative that Ergon Energy has:	
8.3(a)	commenced during the current regulatory control period; and	The key non-network alternatives in the current period are identified in ‘Demand Management Regulatory Proposal (2020-2025)’ document, specifically in section 3 and Appendix One (Attachment 7.051) The following Ergon Energy Reports: • Ergon Energy Demand Management Outcomes Report 2015-16 (Attachment 17.033) • Ergon Energy Demand Management Outcomes Report 2016-17 (Attachment 17.034) • Ergon Energy Demand Management Outcomes Report 2017-18 (Attachment 17.035), and • Demand Management Plan (Attachment 6.001).

8.3(b)	selected to commence during, or will continue into, the forthcoming regulatory control period.	For demand management Targeted Area initiatives, the location, problem statement and incentive offer will be published on the Ergon Energy incentive maps and web pages, refer to https://www.ergon.com.au/network/manage-your-energy/incentives/search-incentives These are updated as network constraints and risks of exceeding capacity are identified.
8.4	For each non-network alternative identified in the response to paragraph 8.3, provide a description, including cost and location.	The key non-network alternatives in the current period are identified in 'Demand Management Regulatory Proposal (2020-2025)' specifically section 4 and Appendix (Attachment 7.051).
8.5	Provide, for each year of the current regulatory control period, and for the forthcoming regulatory control period, details of each payment made, or expected to be made, by Ergon Energy to an Embedded Generator in reflection any costs avoided by deferring augmentation of:	Information on embedded generator contracts is detailed in Demand Management Regulatory Proposal (2020-2025) Appendix One (Attachment 7.051).
8.5(a)	Ergon Energy's distribution network; or	Refer to response 8.5.
8.5(b)	the relevant transmission network.	Not applicable
9	**FORECAST INPUT PRICE CHANGES**	
9.1	Provide, in Workbook 1 – Regulatory determination, regulatory template CPI series, the CPI series and index used by Ergon Energy in its forecast capex proposal also the CPI series and index used by Ergon Energy in its forecast opex proposal.	Ergon Energy used the June CPI series for the eight capital cities that is published quarterly by the Australian Bureau of Statistics (ABS) for historical inflation up to June 2018. The CPI series is provided in "Workbook 1 – Regulatory Determination" (Attachment 17.053 - 2020-25 Regulatory Determination RIN template) in accordance with the AER's instructions. This CPI series is also replicated in various models that we are submitting, for instance, 'Opex forecast – SCS' (Attachment 6.008), 'Opex forecast – ACS metering' (Attachment 15.011), 'Opex forecast – Public Lighting Conventional' (Attachment 15.013), and 'Opex forecast – Public Lighting LED (Attachment

		15.015). The CPI series in these models convert historical values in to real $2020, together with inflation forecasts published by the Reserve Bank of Australia in its November 2018 Statement on Monetary Policy.
9.2	Provide, in Workbook 1 – Regulatory determination, regulatory template 2.14, the capex and opex price changes assumed by Ergon Energy in its forecast capex proposal and the forecast opex proposal. All price changes must be expressed in percentage year on year real terms.	Refer to 2020-25 Regulatory Determination RIN template (Attachment 17.053) and: • Forecast Capex Model (Attachment 7.154) • Fee based and quoted services model - ACS (Attachment 15.009). • Opex forecast – SCS model (Attachment 6.008) • Opex forecast – ACS Metering (Attachment 15.011) • Capex forecast – ACS Metering (Attachment 15.008) • Opex forecast – ACS Public Lighting Conventional (Attachment 15.013) • Opex forecast – ACS Public Lighting LED (Attachment 15.015) • Capex forecast – ACS Public Lighting Conventional (Attachment 15.032), and • Capex forecast – ACS Public Lighting LED (Attachment 15.034).
9.3	Provide:	
9.3(a)	the model(s) used to derive and apply the materials price changes, including model(s) developed by a third party;	Ergon Energy is not proposing any (real) materials escalators. Rather, Ergon Energy is proposing that the cost of materials escalates consistent with forecast inflation.
9.3(b)	in relation to labour escalators, a copy of the current Enterprise Bargaining Agreement or equivalent agreement; and	Please see “Energy Queensland: Enterprise Bargaining Agreement” (Attachment 17.026).
9.3(c)	documents supporting or relied upon that accurately explain the change in the price of goods and services purchased by Ergon Energy, including evidence that any materials price forecasting method explains the price of materials previously purchased by	As noted in response to 9.3(a), Ergon Energy is not proposing any (real) materials escalators. This means that Ergon Energy has not developed or relied upon any documents to support material escalators, including any that explain the change in price of goods and services purchased.

	Ergon Energy .	
9.4	Provide also an explanation of :	
9.4(a)	the methodology underlying the calculation of each price change, including:	Ergon Energy has not included any real material cost escalators in our forecast. For real labour escalators, Ergon Energy has applied a labour cost escalator of 0.26% on average per year. This was calculated by taking the average of the forecasts from BIS Oxford and Deloitte Access Economics (DAE) (being 0.85% annually for the regulatory control period) and subtracting 0.59% annually reflecting our management commitment to improve our program of works delivery by 3% over the regulatory control period. Ergon Energy commissioned BIS Oxford to provide us with real labour escalator forecasts and adopted the DAE forecasts used by the AER in its draft Determination for the NSW distributors, expecting the AER to commission DAE labour forecasts for Queensland in due course.[1] The reports – listed below – explain the methodology, sources, and data conversions used to calculate the labour cost escalator forecasts. Ergon Energy was not provided and do not have access to the models used by either DAE or BIS to prepare their respective forecasts: • Deloitte Access Economics, Labour Price Growth Forecasts (Attachment 6.006) • BIS Oxford Economics, Cost Escalation Forecasts to 2024-25 (Attachment 6.005) For both forecasts the wage price index measure was used. For the DEA forecast, Ergon Energy used the real escalator for the utilities industry, unadjusted for productivity. For the BIS Oxford forecast, Ergon Energy used the real escalator for the electricity, gas, water and waste services industry.
9.4(a)(i)	sources;	As noted above, these are explained in the reports from DAE and BIS Oxford.

[1] AER – Power and Water 2019-24 – Draft Decision – opex model – September 2018_0 - Excel, Input | rate of change.

9.4(a)(ii)	data conversions;	As noted above, these are explained in the reports from DAE and BIS Oxford.
9.4(a)(iii)	the operation of any model(s) provided under paragraph 9.3(a); and	As noted in response to 9.3(a), Ergon Energy is not proposing any (real) materials escalators, and so have not relied on any model to derive and apply the materials price changes.
9.4(a)(iv)	the use of any assumptions such as lags or productivity gains;	Ergon Energy is applying a 2.58% per annum productivity factor to reflect our management initiatives to reduce overhead costs.
9.4(b)	whether the same price changes have been used in developing both the forecast capex proposal and forecast opex proposal; and	The same price changes have been used in developing both the capex and opex forecasts. These are reflected in the following models: • Forecast Capex Model (Attachment 7.154) • Opex forecast – SCS model (Attachment 6.008) • Capex forecast – ACS metering (attachment 15.008) • Capex forecast – ACS public lighting conventional (attachment 15.032) • Capex forecast – ACS public lighting LED (attachment 15.034) • Opex forecast – ACS Metering (Attachment 15.011) • Opex forecast – ACS Public Lighting conventional (Attachment 15.013), and • Opex forecast – ACS public lighting LED (attachment 15.015).
9.4(c)	if the response to paragraph 9.4(b) is negative, why it is appropriate for different expenditure escalators to apply.	As noted in 9.4(b) above, the same price escalation rates (i.e. labour, contractor and materials) are proposed for both forecast capex and opex.
9.5	If an agreement provided in response to paragraph 9.3(b) is due to expire during the forthcoming regulatory control period, explain the progress and outcomes of any negotiations to date to review and replace the current agreement.	Refer response 9.3. The current Energy Queensland Enterprise Bargaining Agreement has a nominal expiry date of 1 March 2021. Planning and preparation for negotiations for a replacement Enterprise Agreement will commence in 2020.
10	**OPERATING AND MAINTENANCE EXPENDITURE**	
	Total forecast operating and maintenance expenditure (opex)	

10.1	Provide:	
10.1(a)	the model(s) and the methodology Ergon Energy used to develop total forecast opex;	Ergon Energy has provided Opex forecast – SCS model (Attachment 6.008) which was used to develop total forecast opex for SCS. The methodology underlying Ergon Energy's total forecast opex is discussed in chapter 6 of the Regulatory Proposal, and is supported by the 'Base Year Opex Overview' document (Attachment 6.003), Ergon Energy has also provided the following models for ACS prepared using a limited building block approach: • Opex forecast – ACS Metering (Attachment 15.011) • Opex forecast – ACS Public Lighting Conventional (Attachment 15.013), and • Opex forecast – ACS Public Lighting LED (Attachment 15.015).
10.1(b)	justification for Ergon Energy's total forecast opex, including:	
10.1(b)(i)	why the proposed total forecast opex is required for Ergon Energy to achieve each of the objectives in clause 6.5.6(a) of the NER;	Ergon Energy has demonstrated how our total forecast opex achieves each of the objectives in 6.5.6(a) of the NER in the document 'Capex and Opex Objectives, Criteria and Factors in Chapter 6 of the NER' (Attachment 1.006).
10.1(b)(ii)	how Ergon Energy 's total forecast opex reasonably reflects each of the criteria in clause 6.5.6(c) of the NER; and	Ergon Energy has demonstrated how our total forecast opex reasonably reflects each of the criteria in 6.5.6(c) of the NER in the document 'Addressing the Capex and Opex Objectives, Criteria and Factors in Chapter 6 of the NER' (Attachment 1.006).
10.1(b)(iii)	how Ergon Energy 's total forecast opex accounts for the factors in clause 6.5.6(e) of the NER;	Ergon Energy has demonstrated how our total forecast opex accounts for the factors in 6.5.6(e) of the NER in the document 'Capex and Opex Objectives, Criteria and Factors in Chapter 6 of the NER' (Attachment 1.006).
10.2	Provide:	

10.2(a)	the quantum of non-recurrent opex for each year of the forthcoming regulatory control period; and	All non-recurrent costs have been removed from Ergon Energy's base year opex forecast; therefore Ergon Energy has not forecast any non-recurrent costs for the 2020-2025 regulatory period. Ergon Energy has used the opex forecast model typically used by the AER in its more recent regulatory decisions to apply the base step trend (BST) method. In applying this method, debt raising costs have not been included as these are separately accounted for – on a benchmark basis – in Ergon Energy's proposed revenue models including PTRM - SCS (Attachment 8.004), PTRM – ACS Metering (Attachment 15.017), PTRM – Public Lighting Conventional (Attachment 15.019) and PTRM – Public Lighting LED (Attachment 15.021).
10.2(b)	an explanation of the driver of each non-recurrent opex.	Refer to response to 10.2(a), noting Ergon Energy has not forecast any non-recurrent costs.
10.3	If Ergon Energy used a revealed cost base year approach to develop its total forecast opex proposal, provide:	
10.3(a)	in Microsoft Excel format, reconciliation (including all calculations and formulae) of Ergon Energy 's forecast total opex proposal to forecast standard control services opex by opex driver in Workbook 1 – regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3;	This is set out in Microsoft Excel form in the following models: • Reset RIN Population Model - (Attachment 17.066), and • Opex forecast – SCS model - (Attachment 6.008).
10.3(b)	the base year Ergon Energy used; and	As noted in chapter 6 of Ergon Energy's Regulatory Proposal, and 'Base Year Opex Overview' document (Attachment 6.003), Ergon Energy has used 2018-19 as the base year for forecasting opex in our Regulatory Proposal.
10.3(c)	explanation and justification for why that base year represents efficient and recurrent costs.	Ergon Energy has explained and justified this base year in chapter 6 of our Regulatory Proposal document and 'Base Year Opex Overview' document (Attachment 6.003). In summary, 2018-19 was selected as a base year because it: • Will be the most recent full regulatory year of actual reported expenditure at the time the AER will make its final determination on our Regulatory Proposal

		• Is the first year where our operations – and associated costs – largely reflect a harmonised approach following the establishment of Energy Queensland and the joint management of Ergon Energy and Ergon Energy • Reflects the efficiencies that have been achieved in the current regulatory control period, noting that our actual opex has reduced over the current regulatory control period and is estimated to be below the AER's allowance for the last two years of the current regulatory control period • Is efficient when tested against the econometric models considered in the AER's 2018 Annual Benchmarking Report, and • Is consistent with applying the Efficiency Benefit Sharing Scheme for the 2020-25 regulatory control period.
10.4	If Ergon Energy does not use a revealed cost base year approach to develop its total forecast provide:	
10.4(a)	forecast expenditure by opex category in Workbook 1 – Regulatory determination, regulatory template 2.16 for standard control services opex and dual function asset opex in tables 2.16.2 and 2.16.4;	Ergon Energy has used a revealed cost base year approach as set out in Chapter 6 of the Regulatory Proposal. For this reason, Ergon Energy has not provided a response to this question.
10.4(b)	in Microsoft Excel format, clear reconciliation (including all calculations and formulae) of Ergon Energy 's total forecast opex proposal to forecast standard control services opex by opex category in Workbook 1 – regulatory determination, regulatory template 2.16, table 2.16.2 and 2.16.4;	Refer to response to 10.4(a), noting Ergon Energy has used a revealed base year cost.
10.4(c)	explanation of major drivers for the increases and decreases in expenditure by opex category in the forthcoming regulatory control period compared to actual historical expenditure;	Refer to response to 10.4(a), noting Ergon Energy has used a revealed base year cost.
10.4(d)	explanation and justification for:	
10.4(d)(i)	whether Ergon Energy considers there is a year of historic opex	Refer to response to 10.4, noting Ergon Energy has used a revealed base year

	that represents efficient and recurrent costs; or	cost.
10.4(d)(ii)	why Ergon Energy considers no year of historic opex represents efficient and recurrent costs.	Refer to response to 10.4, noting Ergon Energy has used a revealed base year cost.
	Output growth	
10.5	Provide the amount of total forecast opex attributable to output growth changes for standard control services opex and dual function assets opex in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3.	Forecast output growth changes for SCS are provided in chapter 6 of Ergon Energy's Regulatory Proposal. Template 2.16 has been completed in accordance with the AER's instructions. Table 2.16.1 was populated using 'Reset RIN population model' (Attachment 17.066), which links to the Opex forecast – SCS model (Attachment 6.008) used to develop our output growth forecast. •
10.6	Provide:	
10.6(a)	the output growth drivers Ergon Energy used to develop the amount of total forecast opex attributable to output growth changes;	Customer numbers, circuit length, ratcheted maximum demand and energy throughput (consumption) drivers were used to forecast output growth. Ergon Energy applied the four models used by the AER to determine the output change measures and their respective weightings based on the 2018 Annual Benchmarking Report. This is consistent with the method used by the AER in recent decisions for other distribution network service providers (DNSPs). The drivers are combined in the following forecast opex models: • Opex forecast – SCS model (Attachment 6.008) • Opex forecast – ACS Metering (Attachment 15.011) • Opex forecast – ACS Public Lighting Conventional (Attachment 15.013), and • Opex forecast – ACS Public Lighting LED (Attachment 15.015). The driver forecasts are sourced from the Distribution annual planning review and Distribution Annual Planning Report (DAPR), refer to Attachment 7.050.

10.6(b)	any economies of scale factors applied to the growth drivers;	Consistent with the method used by the AER in recent decisions, Ergon Energy has not applied any economies of scale factors to the growth drivers. This is demonstrated in the following forecast opex models: • Opex forecast – SCS model (Attachment 6.008) • Opex forecast – ACS Metering (Attachment 15.011) • Opex forecast – ACS Public Lighting Conventional (Attachment 15.013), and • Opex forecast – ACS Public Lighting LED (Attachment 15.015).
10.6(c)	evidence that the growth drivers explain cost changes due to output growth; and	As noted in Chapter 6 of the Regulatory Proposal, Ergon Energy has applied the output change measures and respective weightings that are detailed in the Economic Insights memo released with the AER's 2018 Annual Benchmarking Report.
10.6(d)	if Ergon Energy applied any composite multiple output growth drivers:	
10.6(d)(i)	the inputs for each composite multiple output growth driver; and	Ergon Energy did not apply any composite multiple output growth drivers. Ergon Energy applied the output change measures and respective weightings that are detailed in the Economic Insights memo released with the AER's 2018 Annual Benchmarking Report.
10.6(d)(ii)	the weightings for each input.	Ergon Energy did not apply any composite multiple output growth drivers. Ergon Energy applied the output change measures and respective weightings that are detailed in the Economic Insights memo released with the AER's 2018 Annual Benchmarking Report.
10.7	Provide an explanation of how, in developing the amount of total forecast opex attributable to output growth changes, Ergon Energy:	
10.7(a)	applied the output growth drivers; and	The growth forecasts are applied to Ergon Energy's proposed SCS and ACS metering and public lighting opex forecasts via the following models:

		• Opex forecast – SCS model (Attachment 6.008) • Opex forecast – ACS Metering (Attachment 15.011) • Opex forecast – ACS Public Lighting Conventional (Attachment 15.013), and • Opex forecast – ACS Public Lighting LED (Attachment 15.015). In summary, Ergon Energy applied the method reflected in the opex model typically used by the AER in recent decisions, which involves: • Forecasting the growth drivers • Weighting these growth drivers in to a single output growth factor • Combining this output growth factor with the forecast price change and productivity change factors to get a single opex rate of change, and • Applying the single rate of change to base year opex. Ergon Energy has also provided the model underlying the application of output growth drivers to derive total forecast opex. Please see "Opex forecast – SCS model" (Attachment 6.008).
10.7(b)	accounted for economies of scale.	No economies of scale were explicitly applied when applying the output growth drivers.
	Real price changes	
10.8	Provide the amount of total forecast opex attributable to changes in the price of labour and materials for standard control services opex and dual function assets opex in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3.	Ergon Energy has completed template 2.16 in accordance with the AER's instructions.
10.9	Provide an explanation of:	
10.9(a)	how, in developing the amount of total forecast opex attributable to changes in the price of labour and materials, Ergon Energy applied the real price measures in Workbook 1 – regulatory determination, regulatory template 2.14; and	Chapter 6 of Ergon Energy's Regulatory Proposal explains our method for developing the total amount of forecast opex attributable to changes in the prices of labour and materials. In summary, Ergon Energy: • Split the base year opex into labour and non-labour components using the

		weights (59.7%/40.3%) reflected in the AER draft Determination for the NSW distributors • For the labour component, we used the labour escalators described in response to 9 above • For the non-labour (i.e. materials) component, we assumed no real price changes.Combined the real labour escalator with the (zero) real materials escalator and the assumed weights to get a single forecast price change factorCombined this price change factor with the forecast output growth and productivity change factors to get a single opex rate of change, andApplied the single rate of change to base year opex. This method was applied in the following models: • Opex forecast – SCS model (Attachment 6.008) • Opex forecast – ACS Metering (Attachment 15.011) • Opex forecast – ACS Public Lighting Conventional (Attachment 15.013), and • Opex forecast – ACS Public Lighting LED (Attachment 15.015).
10.9(b)	whether Ergon Energy 's labour price measure compensates for any form of labour productivity change.	Ergon Energy has used a wage (or labour) price index. This does not directly factor in labour productivity. However, as discussed in chapter 6 of our Regulatory Proposal, a labour cost escalator of 0.26% on average per year was applied to reflect the management's commitment to improve program of works delivery by 3% over the forecast period.
	Productivity change	
10.10	Provide the amount of total forecast opex attributable to changes in productivity for standard control services opex and dual function assets opex in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3.	Ergon Energy has completed template 2.16 in accordance with the AER's instructions as can be demonstrated in the Regulatory Determination RIN template (Attachment 17.053). This has been derived from data in "Reset RIN Population Model" (Attachment 17.066).
10.11	Provide, in percentage year on year terms, the productivity	As noted in Chapter 6 of Ergon Energy's Regulatory Proposal, Ergon Energy is

	measure that Ergon Energy used to develop the amount of total forecast opex attributable to changes in productivity.	committed to pursuing further savings over the 2020-25 regulatory control period. Therefore, Ergon Energy is proposing a positive productivity saving based on the top-down management initiative of 10% total indirect cost savings, and other targeted cost reductions, which results in an overall productivity saving for SCS of 14% over the 2020-25 regulatory control period, or 2.58% per annum. In this way, the savings will be progressively achieved through a structured program throughout 2020-25. For ACS we applied the same productivity improvements as for SCS. For Public Lighting, further productivity gains were assumed in line with the implementation of LEDs which have significantly lower operating and maintenance costs than conventional lights. Ergon Energy expects that, because of our targeted productivity savings, we will at least maintain our relative performance as benchmarked against our peers, with an aspiration to improve. This is reflected in: • Opex forecast – SCS JAN19 PUBLIC (attachment 6.008) • Opex forecast – ACS metering JAN19 PUBLIC (attachment 15.011) • Opex forecast – ACS public lighting CON JAN19 PUBLIC (attachment 15.013) • Opex forecast – ACS public lighting LED JAN19 PUBLIC (attachment 15.015)
10.12	Provide an explanation of:	
10.12(a)	how, in developing the amount of total forecast opex attributable to changes in productivity, Ergon Energy applied the productivity measure in paragraph 10.11;	The 2.58% annual productivity adjustment was applied in the following models: • Opex forecast – SCS JAN19 PUBLIC (attachment 6.008) • Opex forecast – ACS metering JAN19 PUBLIC (attachment 15.011) The 8% annual productivity adjustment for three years was applied in the following models:

		• Opex forecast – ACS public lighting LED JAN19 PUBLIC (attachment 15.014)
10.12(b)	whether Ergon Energy 's forecast productivity changes capture the historic trend of cost increases due to changes in regulatory obligations or requirements and industry best practice; and	As noted above, Ergon Energy is committed to pursuing further savings over the 2020-25 regulatory control period. Therefore, Ergon Energy is proposing a positive productivity saving based on the top-down management initiative of 10% total indirect cost savings, and other targeted cost reductions, which results in an overall productivity saving of 14% for SCS over the 2020-25 regulatory control period, or 2.58% per annum.
10.12(c)	whether Ergon Energy 's productivity measure includes productivity change compensated for by the labour price measure used by Ergon Energy to forecast the change in the price of labour.	As noted in response to 10.9(b), a labour cost escalator of 0.26% on average per year has been applied to reflect Ergon Energy management's commitment to improve program of works delivery by 3% over the forecast period.
11	**STEP CHANGES**	
11.1	Provide the amount of total forecast opex attributable to opex step changes for standard control services opex and dual function assets opex in Workbook 1 – Regulatory determination, regulatory template 2.16, tables 2.16.1 and 2.16.3.	Ergon Energy has not proposed any step changes as part of the BST opex forecasts for either SCS or ACS.
11.2	Provide an explanation of why Ergon Energy considers:	
11.2(a)	the efficient costs of the step change are not provided by other components of Ergon Energy 's total forecast opex such as base opex, output growth changes, real price changes or productivity change;	Refer to response 11.1. Ergon Energy has not proposed any step changes in forecast expenditures.
11.2(b)	the total forecast opex will not allow Ergon Energy to achieve the objectives in clause 6.5.6(a) of the NER unless the step change is included; and	Refer to response 11.1. Ergon Energy has not proposed any step changes in forecast expenditures.
11.2(c)	the total forecast opex will not reasonably reflect the criteria in clause 6.5.6(c) of the NER unless the step change is included.	Refer to response 11.1. Ergon Energy has not proposed any step changes in forecast expenditures.

11.3	For all step changes in forecast expenditure provide:	
11.3(a)	In Workbook 1 – Regulatory determination, regulatory template 2.17 the quantum of the step changes :	Refer to response 11.1. Ergon Energy has not proposed any step changes in forecast expenditures.
11.3(a)(i)	forecasts for each year of the forthcoming regulatory control period; and	Refer to response 11.1. Ergon Energy has not proposed any step changes in forecast expenditures.
11.3(a)(ii)	expected to be incurred, in the current regulatory control period;	Refer to response 11.1. Ergon Energy has not proposed any step changes in forecast expenditures.
11.3(b)	a description of the step change.	Refer to response 11.1. Ergon Energy has not proposed any step changes in forecast expenditures.
11.4	For each step change listed in response to paragraph 11.3, provide an explanation of:	
11.4(a)	when the change occurred, or is expected to occur;	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.4(b)	what the driver of the step change is;	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.4(c)	how the driver has changed or will change (for example, revised legislation may lead to a change in a regulatory obligation or requirement); and	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.4(d)	whether the step change is recurrent in nature.	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.5	For each step change listed in response to paragraph 11.3, provide justification for when, and how, the step change affected, or is expected to affect:	

11.5(a)	the relevant opex category;	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.5(b)	the relevant capex category;	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.5(c)	total opex; and	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.5(d)	total capex.	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.6	For each step change registered in response to paragraph 11.3, provide the process undertaken by Ergon Energy to identify and quantify the step change; provide cost benefit analysis that demonstrates Ergon Energy proposes to address the step change in a prudent and efficient manner, including:	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.6(a)	the timing of the step change; and	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.6(b)	if Ergon Energy considered a ‘do nothing’ option, evidence of how Ergon Energy assessed the risks of this option compared with other options.	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.7	For each step change listed in response to paragraph 11.3, where the step change is due to a change in a regulatory obligation or requirement provide:	
11.7(a)	any relevant variations or exemptions granted to Ergon Energy during the previous regulatory control period or the current regulatory control period; and	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.

11.7(b)	any relevant compliance audits Ergon Energy conducted during the previous regulatory control period or the current regulatory control period.	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.8	For each step change registered in response to paragraph 11.7, provide, with reference to specific clauses of the relevant legislative instrument(s), the:	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.8(a)	previous regulatory obligation or requirement; and	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
11.8(b)	how the changed regulatory obligation or requirement is driving the step change.	Refer to response 11.3. Ergon Energy has not proposed any step changes in forecast expenditures.
	Category specific opex	
11.9	Provide the amount of total forecast opex attributable to category specific opex in Workbook 1 – Regulatory determination, regulatory template 2.17, table 2.17.5. The amount of total opex attributable to category specific opex must correspond with the category specific opex reported in Workbook 1 – Regulatory determination, regulatory template 2.16, table 2.16.1.	Ergon Energy has completed Template 2.17, table 2.17.5 in accordance with the AER's instructions. Ergon Energy has populated this table using 'Reset RIN population model' (Attachment 17.066).
12	**ECONOMIC BENCHMARKING**	
12.1	Complete the Workbook 1 – Regulatory determination, regulatory templates 3.1 to 3.7 in accordance with:	Ergon Energy has completed regulatory templates 3.1 to 3.7 in Workbook 1 – Regulatory Determination (Attachment 17.053).
12.1(a)	the 'Economic Benchmarking RIN for distribution network service providers – Instructions and Definitions' issued to Ergon Energy on 28 November 2013, chapters 2 to 9;	Ergon Energy has completed regulatory templates 3.1 to 3.7 of Workbook 1 – Regulatory Determination (Attachment 17.053) in accordance with the 'Economic Benchmarking RIN for distribution network service providers – Instructions and Definitions' issued to Ergon Energy on 28 November 2013, chapters 2 to 9.

12.1(b)	paragraphs 12.2 to 12.10.	Refer response 12.2. Ergon Energy has completed regulatory templates 3.1 to 3.7 of Workbook 1 – Regulatory Determination (Attachment 17.053) in accordance with paragraphs 12.2 to 12.10 of the AER's Reset RIN.
12.2	The forecast revenue groupings in Workbook 1 – Regulatory determination, regulatory templates 3.1, tables 3.1.1 and 3.1.2 may be developed by trending forward actual historical revenue groupings in previous regulatory years. However:	
12.2(a)	Total revenues must equal the total forecast revenues proposed by Ergon Energy in its regulatory proposal; and	Ergon Energy notes that forecast revenues in regulatory template 3.1 of Workbook 1 – Regulatory Determination (Attachment 17.053) are consistent with forecast revenues presented in the Regulatory Proposal.
12.2(b)	Revenue groupings must reflect Ergon Energy 's forecast demand for its services in the forthcoming regulatory control period in its regulatory proposal.	Ergon Energy has complied with the AER's instructions as the revenue groupings in regulatory template 3.1 in Workbook 1 – Regulatory Determination are consistent with forecast demand for services in the Regulatory Proposal.
12.3	Information provided in Workbook 1 – Regulatory determination, regulatory templates 3.2, tables 3.2.1 and 3.2.2 must reflect Ergon Energy's cost allocation method.	Ergon Energy has complied with the AER's instructions for regulatory template 3.2 in Workbook 1 – Regulatory Determination (Attachment 17.053), including that it reflects Ergon Energy's approved CAM.
12.4	RAB asset financial data in the Workbook 1 – Regulatory determination, regulatory template 3.3 must reconcile to that in Ergon Energy's regulatory proposal PTRM and RFM.	The regulatory asset base (RAB) asset financial data in regulatory template 3 of Workbook 1 – Regulatory Determination (Attachment 17.053) reconcile to that in the Regulatory Proposal PTRM-SCS (Attachment 8.004) and RFM-SCS (Attachment 8.008).
12.5	The definition of a tree must be applied when completing the variables "Average number of trees per urban and CBD vegetation maintenance span" (DOEF0208) and "Average number of trees per rural vegetation maintenance span" (DOEF0209)	Ergon Energy has applied the definition of a tree when completing variables DOEF0208 and DOEF0209 in Workbook 1 – Regulatory determination, regulatory template 3.7.
12.6	In calculating responses to the variables DOEF0202 to DOEF0205, spans in the network service area where Ergon Energy is not responsible for the vegetation management associated with the	In preparing Workbook 1 – Regulatory determination, regulatory template 3.7 Ergon Energy has not counted the spans in the network service areas where it is not responsible for the vegetation management associated with the span (variables

	span are not to be counted.	DOEF0202 to DOEF0205).
12.7	“Total number of spans” (DOEF0205) does not include service line spans.	In preparing Workbook 1 – Regulatory determination, regulatory template 3.7, Ergon Energy confirms that the “Total number of spans” (DOEF0205) does not include service line spans.
12.8	Ergon Energy must report the route line length of feeders classified as either short rural or long rural divided by the total route feeder line length (this is the total feeder route line length for all CBD, urban, short rural and long rural feeders) against “Rural proportion” (DOEF0201).	In preparing Workbook 1 – Regulatory determination, regulatory template 3.7, Ergon Energy has reported the route line length of feeders classified as either short rural or long rural divided by the total route feeder line length against “Rural proportion” (DOEF0201).
12.9	For the purposes of calculating the “Route line length” variable (DOEF0301) or other variables measured in terms of route line length:	
12.9(a)	the length of service lines is not to be counted	In preparing Workbook 1 – Regulatory determination, regulatory template 3.7, the length of service lines has not been counted for the purposes of calculating the “Route line length” variable (DOEF0301) or other variables measured in terms of route line length.
12.9(b)	the length of a span that shares multiple voltage levels is only to be counted once	In preparing Workbook 1 – Regulatory determination, regulatory template 3.7 the length of a span that shares multiple voltage levels is only counted once for the purposes of calculating the “Route line length” variable (DOEF0301) or other variables measured in terms of route line length.
12.9(c)	the lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately	In preparing Workbook 1 – Regulatory determination, regulatory template 3.7, Ergon Energy confirms that lengths of two sets of lines that run on different sets of poles (or towers) but share that same easement are counted separately for the purposes of calculating the “Route line length” variable (DOEF0301) or other variables measured in terms of route line length.
12.10	All forecast variables in the Workbook 1 – Regulatory determination, regulatory templates 3.1 to 3.7 must align with those	All forecast variables reported in templates 3.1 and 3.7 of Workbook 1 – Regulatory Determination (Attachment 17.053) are consistent with the documents submitted

	in Ergon Energy's regulatory proposal. For the avoidance of doubt this includes forecast:	as part of the Regulatory Proposal.
12.10(a)	opex and capex;	Refer to response 12.10.
12.10(b)	maximum demand, energy delivery;	Refer to response 12.10.
12.10(c)	revenues;	Refer to response 12.10.
12.10(d)	quality of services variables including SAIDI and SAIFI; and	Refer to response 12.10.
12.10(e)	quantities of physical assets.	Refer to response 12.10.
13	**ALTERNATIVE CONTROL SERVICES**	
13.1	The overheads relating to each alternative control service listed in paragraph 13.2 must be disclosed.	For fee based and quoted services, Ergon Energy has outlined the overheads in the ACS – Fee based and quoted services model (Attachment 15.009). Metering and public lighting forecasts have been prepared using a limited building block approach. Opex has been forecast using the same BST approach used for SCS. Therefore overheads cannot be separately identified. However, capitalised overheads are set out in the following models: • Capex forecast – ACS metering (Attachment 15.008) • Capex forecast – ASC public lighting conventional (Attachment 15.032); and • Capex forecast – ACS public lighting LED (Attachment 15.034).
13.2	Provide a list of all of the alternative control services that Ergon Energy intends to provide to customers and levy charges for in the forthcoming regulatory control period.	Ergon Energy has provided a list of each ACS that we intend to provide customers in: • Alternative Control Services (Attachment 15.006), • 2020-2025 Tariff Structure Statement (Attachment 14.002), and TSS Explanatory Notes (Attachment 14.004),

		• ACS metering pricing model (Attachment 15.028) • ACS public lighting LED and conventional pricing model (Attachment 15.030) and • Fee based and quoted services model - ACS (Attachment 15.009).
13.3	Provide a definition of each alternative control service listed in paragraphs 14, 15 and 16.	Ergon Energy has provided a definition of each ACS that we intend to provide customers in: • Alternative Control Services (Attachment 15.006) • 2020-2025 Tariff Structure Statement (Attachment 14.002), and TSS Explanatory Notes (Attachment 14.004), and • Fee based and quoted services model – ACS (Attachment 15.009).
13.4	For each alternative control service (excluding quoted services) listed in paragraphs 14, 15 and 16, specify the charges applicable during each year of the current regulatory control period. Also include proposed charges for each year of the forthcoming regulatory control period.	Charges for the proposed ACS in the forthcoming regulatory control period have been developed in accordance with the formula set in the proposed 2020-2025 Tariff Structure Statement (Attachment 14.002). The charges for the current regulatory control period have been developed in accordance with the formula set in the 2017-2020 Tariff Structure Statement, which was approved by the AER. Charges for fee based services for the current and forthcoming regulatory control periods are set out in Attachment 17.067 For public lighting and metering, charges for the current regulatory control period are set out in the relevant annual Pricing Proposal approved by the AER. = These documents are available on the Ergon Energy website. The charges applicable for the forthcoming regulatory control period have been provided in: • ACS metering pricing model (Attachment 15.028), and • ACS public lighting LED and conventional pricing model (Attachment 15.030)
13.5	For each alternative control service (excluding quoted services) listed in paragraphs 14, 15 and 16, specify the total revenue earned by Ergon Energy in each year of the current regulatory	Ergon Energy has outlined the total ACS revenue earned by Ergon Energy in each year of the current regulatory control period in 'ACS Supporting Information (Reset

	control period and forecast to be earned in the forthcoming regulatory control period.	RIN Schedule 1 s13.5 - 13.6)’ document (Attachment 17.001). For the forthcoming regulatory control period the information is provided in: • Alternative Control Services (Attachment 15.006) • PTRM – ACS metering (Attachment 15.017) • PTRM – ACS public lighting conventional (Attachment 15.019) • PTRM – ACS public lighting LED (Attachment 15.021), and • ACS – Fee based and quoted services model (Attachment 15.009).
13.6	For quoted services (in aggregate) specify the total revenue earned in each year of the current regulatory control period and forecast to be earned in the forthcoming regulatory control period.	Refer to ‘ASC Supporting Information (Reset RIN Schedule 1 s13.5 - 13.6)’ (Attachment 17.001) for the total revenue earned for quoted services in each year of the current regulatory period and forecast to be earned in the forthcoming regulatory control period.
13.7	For each alternative control service listed in paragraphs 14, 15 and 16, provide the labour rate(s) used to calculate the charges for the current and forthcoming regulatory control periods:	Charges for public lighting and metering are based on a limited building block approach and therefore labour rates are not applicable. For fee and quoted services refer to ‘ACS Supporting Information (Reset RIN Schedule 1 s13 and s14)’ (Attachment17.067).
13.7(a)	specify the labour classification level used to provide the services e.g. outsourced or internally provided and labourer type;	As noted above, charges for public lighting and metering are based on a limited building block approach and therefore labour classifications are not applicable. For fee based services refer to the Fee based and quoted services model – ACS (Attachment 15.009).
13.7(b)	register all direct costs, and their quantum, in the make-up of the labour rate(s).	As noted above, charges for public lighting and metering are based on a limited building block approach and therefore labour classifications are not applicable. For fee based and quoted services refer to Fee based and quoted services model – ACS (Attachment 15.009). .
13.8	List each material category (e.g. meters, poles, brackets) required for the provision of alternative control services registered in the response to paragraphs 14, 15 and 16.	For public lighting, we have identified the light, bracket and pole as the material cost categories. Metering equipment is the only identified material costs for customer initiated

		metering services. For fee based and quoted services, the material cost is dependent on the activity performed, and therefore there is no set schedule of material costs.
13.8(a)	provide a description of each material category;	Light – being the identified costs associate with the luminaire, lamp and associated equipment that provide illumination. Bracket – the identified costs associated with the horizontal arm on which the light is attached. Pole – the identified costs associated with the vertical element on which the bracket is attached. Meter – identified costs relate to the meter and any consumables required for the installation.
13.8(b)	provide the average unit costs for each material category;	For metering refer to 'ACS Supporting Information (Reset RIN Schedule 1 s13 and s14)' (Attachment 17.067) For public lighting refer to response to paragraph 16.2.
13.8(c)	register all direct costs included in the unit costs;	For metering refer to 'ACS Supporting Information (Reset RIN Schedule 1 s13 and s14)' document (Attachment 17.067). For public lighting refer to response to paragraph 16.2.
13.8(d)	specify the calculation of the quantum of direct materials costs included in the unit cost of materials.	Only direct costs are included in the unit costs listed for each material category.
14	**FEE BASED AND QUOTED ALTERNATIVE CONTROL SERVICES**	
14.1	Provide a description of each fee based and quoted service, explaining the purpose of the service and list the activities which comprise each service. The list of fee based and quoted services should be consistent with those services listed in Ergon Energy's	Ergon Energy has provided a description of each ACS that we intend to provide customers in our document, Alternative Control Services (Attachment 15.006).

	annual pricing proposals.	
14.1(a)	specify if the charges are for fee based and/or quoted alternative control services;	Refer to our document Alternative Control Services document (Attachment 15.006).
14.1(b)	explain the reasons for the different charge with reference to the costs incurred;	Fee based services are generally predictable in scope and do not vary greatly with the project. In contrast, quoted services depend on the scope of a customer's request. It is not practical to establish individual fees for quoted services as the costs vary significantly on a project-by-project basis.
14.1(c)	explain the method used to set the different charge; and	Ergon Energy applies the formulae specified in the 2020-25 Tariff Structure Statement (Attachment 14.002) to set the charges for fee based and quoted services Ergon Energy's fee-based services use a bottom-up, input cost model to determine the efficient, cost-reflective charge for each individual service. Ergon Energy's quoted services are based on labour rates per hour (including on-costs and overheads) with materials, contractor and other costs reflecting the costs involved with the specific project.
14.1(d)	provide the calculations underpinning the different charge.	Ergon Energy has provided the calculations for each ACS fee based service and an example of a quoted service in the Fee based and quoted services model – ACS (Attachment 15.009).
14.2	Identify the tasks involved in providing the service described in response to 14.1 including:	Ergon Energy has itemised cost components to complete the task in the in the Fee Based and quoted services model- ASC (Attachment 15.009).
14.2(a)	map the class of labour required to provide the service;	Refer to response 14.2.
14.2(b)	the number of workers required to undertake the task and deliver the service;	Refer to response 14.2.
14.2(c)	the average time required to complete the task and deliver the service.	Refer to response 14.2.
14.3	If materials are required to provide the service, specify each	Ergon Energy has itemised cost components to complete the task in the in the Fee

	material category.	Based and quoted services model- ACS (Attachment 15.009).
14.4	Provide all current and proposed charges for each fee based alternative control service in the current and forthcoming regulatory control periods.	Refer to the response to section 13.4
15	**METERING ALTERNATIVE CONTROL SERVICES**	
15.1	For metering alternative control services for the current regulatory control period and the forthcoming regulatory control period, provide details of the:	In addressing Question 15 of Schedule 1 of the RIN, Ergon Energy has defined metering ACS consistent with the final Framework and Approach paper dated July 2018.
15.1(a)	direct materials and direct labour costs;	The direct material costs include the costs of the meter, and other equipment associated with the meter such as the modem, antenna and communications. Refer to 'Metering ACS Supporting Information (Reset RIN Schedule 1 s15)' (Attachment 17.045). Please note that forecast metering opex applies a BST approach, and therefore we have used 2018-19 opex as a basis for our forecasts.
15.1(b)	installation costs;	For the current period, please refer to 'Metering ACS Supporting Information (Reset RIN Schedule 1 s15)' (Attachment 17.045). For the forthcoming period, please refer to Workbook 1- Regulatory Determination, template 4.3 Fee based services, as meter installation is now a fee based service and not included in Workbook 1 – Regulatory Determination, template 4.2 Metering which only includes default metering costs.
15.1(c)	meter purchase costs;	For the current and forthcoming period, please refer to 'Metering ACS Supporting Information (Reset RIN Schedule 1 s15)' (Attachment 17.045).
15.1(d)	volumes of work;	For the current period, please refer to 'Metering ACS Supporting Information (Reset RIN Schedule 1 s15)' (Attachment 17.045).

		For the forthcoming period, please refer to Template 4.2 in Workbook 1 Regulatory Determination (Attachment 17.053). Information for metering services is provided in the following categories: • Meter Testing - (template 4.2 Default Metering) • Meter Investigation - (template 4.2 Default Metering) • Scheduled Meter Reading - (template 4.2 Default Metering) • Special Meter Reading – (template 4.3 Fee based services • New Meter Installation - (template 4.3 Fee based services • Meter Replacement - (template 4.3 Fee based services) • Meter Maintenance - (template 4.2 Template Default Metering) • Other Metering – Meter Reconfiguration – (template 4.3 Fee based services), and • Other Metering - Meter Data Service - (template 4.2 Default Metering)
15.1(e)	other costs associated with providing metering services;	For the current period, please refer to ‘Metering ACS Supporting Information (Reset RIN Schedule 1 s15)’ - Table 3 (Attachment 17.045) For the forthcoming period, Ergon Energy does not forecast any other costs.
15.1(f)	type of meters installed and forecast to be installed, separately for new meters and for replacement meters;	For the current period, please refer to ‘Metering ACS Supporting Information (Reset RIN Schedule 1 s15)’ (Attachment 17.045). For the forthcoming period, please refer to Workbook 1 – Regulatory Determination, template 4.3 Fee based services (Forecast) as meter installation is classified as a fee based service and not included in Workbook 1- Regulatory Determination, template 4.2 Metering which only includes default metering costs. Note that Ergon Energy is no longer required to install new or replacement meters for Type 6 metering installations connected to the National Electricity Market (NEM) as part of the Power of Choice (PoC) reforms that took effect on 1 December 2017.
15.1(g)	the volume of meters by type set out in (f) and the revenue earned	For the current period volumes, please refer to ‘Metering ACS Supporting

	and forecast to be earned by each meter type; and	Information (Reset RIN Schedule 1 s15)' (Attachment 17.045). For the forthcoming period volumes, please refer to Workbook 1- Regulatory Determination, template 4.3 Fee based services, as meter installation is classified as fee based service and not included in Workbook 1 - Regulatory Determination, template 4.2 -Metering. Template 4.2 – Metering is default metering costs only. For the current and forthcoming period revenue, refer to response 13.5.
15.1(h)	the total operating and maintenance costs incurred, and forecast to be incurred, for metering services.	For the current period, please refer to 'Metering ACS Supporting Information (Reset RIN Schedule 1 s15)' (Attachment 17.045). For the forthcoming period please refer to Table 5 – Forecast opex in our document, Alternative Control Services (Attachment 15.006).
15.2	For metering works, for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period, provide a description of:	
15.2(a)	the type of work undertaken (e.g. meter reconfiguration, special meter read) including a description of the activities undertaken to provide the service;	The activities for the current and forthcoming regulatory control periods are of a similar nature and include the following: • Meter Purchases – the purchasing of meters and communications devices (such as modems and antennas) that meet the specifications required to provide a compliant metering service • Meter Testing – the testing of in-service meters and metering installations to confirm the metering installations accuracy and compliance • Meter Investigation – the investigation of in-service meters and metering installations to ensure metering installation accuracy and compliance • Scheduled Meter Reading – the scheduled reading of meters for accurate customer billing data • Special Meter Reading – the out of cycle reading of meter to support a customer billing or consumption request • New Meter Installation – This involves the installation of a purchased meter in the premise of a customer. The nature of this activity can vary with the

		type of installation and metering requirement • Meter Replacement – The replacement of an existing meter installed in the premise of a customer that has been identified as end of useful life • Meter Maintenance – the preventative or corrective maintenance of a meter or metering installation. The nature of this activity can vary depending on the type of installation and metering requirement, and • Other Metering – All activities not captured by the defined meter services categories including those activities relating to type 7 meters. Note that the service types New Meter Installations and Meter Replacement will not be required for the forthcoming periods for NEM connected customers, as Ergon Energy is no longer required to install new or replacement meters for Types 1-6 metering installations as part of the PoC reforms that took effect on 1 December 2017.
15.2(b)	the labour costs involved in providing the service, including any overheads;	The labour costs relate to meter testing, investigation, scheduled and special reading (excluding the data communication costs), replacement and maintenance as well as administration and training associated with these services. We also allocate overheads to metering services in accordance with the CAM, and some of this may relate to labour hours. This would include labour costs for administration and training, together with the labour costs of Information and Communication Technology. It should be noted that some of the labour costs relate to external providers.
15.2(c)	any materials costs involved in providing the service;	The material costs primarily relate to the purchase of the meter and communications devices (such as modems and antennas).
15.2(d)	the number (volume) of services provided and associated assumptions on which the volume of service was derived or estimated;	For actual volumes in the current period please refer to 'Metering ACS Supporting Information (Reset RIN Schedule 1 s15)' – Table 6 (Attachment 17.045) and break down of service types. For forecast volumes refer to Template 4.2 in Workbook 1 Regulatory Determination. Assumptions have been made in the forecast volumes based on historical trending

		volumes and PoC impacts. Further details are provided below: • No new or replacement meters will be installed for NEM connected customers due to PoC primarily affecting service order categories of New Meter Installation, Meter Replacement and Meter Purchases • Meter population decline of 3% per annum based off trending since PoC implementation • Meter Testing to remain constant in line with the Australian Energy Market Operator's (AEMO) testing obligations and the Meter Asset Management Plan (Attachment 15.002), and • All other service volumes have been evaluated based off trending since PoC implementation.
15.2(e)	the charge per service; and	The charges for metering services are explained in the 2020-25 Tariff Structure Statement (14.001). Refer to the response 13.4 for information on the charges in the current and forthcoming regulatory control periods.
15.2(f)	the revenue earned by each service.	Refer to response 13.5
15.3	For metering alternative control services, specify the number of customers in each year of the current regulatory control period, and forecasts for the forthcoming regulatory control period.	For the current and Forthcoming periods, please refer to 'Metering ACS Supporting Information (Reset RIN Schedule 1 s15)' (Attachment 17.045).
16	**PUBLIC LIGHTING ALTERNATIVE CONTROL SERVICES**	
16.1	Specify which items are capex and operational expenditure for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period.	Refer to: • Alternative Control Services (Attachment 15.006) • Opex forecast – ACS public lighting conventional (Attachment 15.013) • Opex forecast – ACS public lighting LED (Attachment 15.015) • Capex forecast – ACS public lighting conventional (Attachment 15.032) • Capex forecast – ACS public lighting LED (Attachment 15.034)

		• PTRM – ACS public lighting conventional (Attachment 15.019), and • PTRM – ACS public lighting LED (Attachment 15.021).
16.2	Provide unit costs for the current regulatory control period and forecast for the forthcoming regulatory control period for:	
16.2(a)	luminaires;	Refer to Table 2 in this document.
16.2(b)	dedicated street lighting poles;	Refer to response provided to 16.2(a).
16.2(c)	brackets;	Refer to response provided to 16.2(a).
16.2(d)	lamps;	Refer to response provided to 16.2(a).
16.2(e)	photoelectric cells;	Refer to response provided to 16.2(a).
16.2(f)	labour rate (per hour);	Refer to response provided to 13.7.
16.2(g)	miscellaneous materials.	Ergon Energy has not identified any miscellaneous materials costs in the provision of public lighting ACS.
16.3	Provide the depreciation period in years for each type of luminaire.	Ergon Energy uses an average depreciation period of 20 years for all types of luminaires.
16.4	Provide the bulk change cycle in years for lamps and photoelectric cells.	Refer to Asset Management Plan Public Lighting (Attachment 15.003)
16.5	Provide details of the average replacement age of each type of luminaire.	Refer to Asset Management Plan Public Lighting (Attachment 15.003)
16.6	Provide the number of luminaires, by type, for the current and forthcoming regulatory control periods.	For the current regulatory control period refer to Template 4.1 in the Annual Category Analysis RINs previously submitted to the AER. For the forthcoming regulatory control period refer to ACS Public lighting LED and

		Conventional Pricing model (Attachment 15.030).
16.7	Provide the number of luminaires, poles and brackets replaced per year, for the current and forthcoming regulatory control periods.	For the current period refer to Template 4.1 in the Annual Category Analysis RINs previously submitted to the AER. For the forthcoming period refer to Template 4.1 in Workbook 1 – Regulatory Determination. For further information refer to Asset Management Plan Public Lighting (Attachment 15.003)
16.8	Provide details, including assumptions used, for any other costs that are incurred for the provision of public lighting services.	For further information refer to Asset Management Plan Public Lighting (Attachment 15.003).
16.9	Provide models and/or modelling that underpins proposed charges for the forthcoming regulatory control period and the reasons for the assumptions behind those forecasts.	Refer to the following models: • PTRM – ACS public lighting conventional (Attachment 15.019) • PTRM – ACS public lighting LED (Attachment 15.021) • RFM – ACS public lighting conventional(Attachment 15.025) • RFM – ACS public lighting LED (Attachment 15.027), and • ACS Public lighting LED and Conventional Pricing model (Attachment 15.030). For further information about the assumptions refer to Asset Management Plan Public Lighting (Attachment 15.003) and our document, Alternative Control Services (Attachment 15.005).
16.10	For public lighting alternative control services, specify the number of customers in each year of the current regulatory control period, and forecasts for the forthcoming regulatory control period.	Ergon Energy’s customers for public lighting include the 56 local government authorities in Ergon Energy’s area and the Department of Transport and Main Roads.. The customer base will remain unchanged for the entire forthcoming regulatory control period.
17	**DEMAND AND CONNECTIONS FORECASTS**	

17.1	Provide and describe the methodology used to prepare the following forecasts for the forthcoming regulatory control period:	
17.1(a)	maximum demand; and	The methodology for maximum demand forecasts is detailed in the following documents: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001)
17.1(b)	number of new connections.	Ergon Energy considers the number of new connections to refer to customer number forecasts. Refer to Chapter 5 of Ergon Energy's Regulatory Proposal
17.2	Provide:	
17.2(a)	the model(s) Ergon Energy used to forecast new connections and maximum demand;	Ergon Energy has not provided models as the most relevant information is embedded on our internal server. For further information refer to: • Chapter 5 of our Regulatory Proposal • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.2(b)	Where Ergon Energy's approach to weather correction has changed, provide historically consistent weather corrected maximum demand data, as per the format in Workbook 1 – Regulatory determination, regulatory templates 3.4 and 5.4 using Ergon Energy's current approach. If any of this data is unavailable, explain why;	Ergon Energy has provided this information in templates 3.4 to 5.4 of Workbook 1 – Regulatory Determination (Attachment 17.053). For further information refer to: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.2(c)	for new connections, volume expenditure data requested in Workbook 1 – Regulatory determination, regulatory template 2.5; and	Ergon Energy has provided this information in template 2.5 of "Workbook 1 – Regulatory Determination" (Attachment 17.053).
17.2(d)	any supporting information or calculations that illustrate how information extracted from Ergon Energy's forecasting model(s)	Ergon Energy has no further supporting documentation.

	reconciles to, and explains any differences from, information provided in Workbook 1 – Regulatory determination, regulatory templates 2.5, 3.4 and 5.4.	
17.3	For each of the methodologies provided and described in response to paragraph 17.1, and, where relevant, data requested under paragraphs 17.2(b) and 17.2(c), explain or provide (as appropriate):	
17.3(a)	the models used;	Ergon Energy has not provided models as the most relevant information is embedded on our internal server. For further information refer to: • Chapter 5 of our Regulatory Proposal • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(b)	a global (top-down) and spatial (bottom-up) demand forecast;	These demand forecasts are explained in: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(c)	the inputs and assumptions used in the models (including in relation to economic growth, connections numbers and policy changes and provide any associated models or data relevant to justifying these inputs and assumptions);	The inputs and assumptions used in the modelling for customer connections, energy forecasts, regional demand forecasts and zone substation maximum demand forecasts are set out in chapter 5 of our Regulatory Proposal and: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(d)	the weather correction methodology, how weather data has been used, and how Ergon Energy 's approach to weather correction has changed over time;	The weather correction methodology used for our demand forecasts is outlined in: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(e)	an outline of the treatment of block loads, transfers and switching within the forecasting process;	Ergon Energy applied block loads, transfers, and switching periods in the forecast if they were categorised as committed. These were applied as post-model

		adjustments to the zone substation maximum demand forecasts. Typically, these changes were in units of MVA, and were therefore converted to MW using a power factor obtained from historical data. The block loads, transfers, and switching included in the forecasts are summarised in: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(f)	each appliance model used, where used, or assumptions relating to average customer energy usage (by customer type);	Ergon Energy's energy forecasting process did not apply an appliance model approach. Our approach for deriving energy forecasts is explained in chapter 5 of our Regulatory Proposal and ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(g)	how the forecasting methodology used is consistent with, and takes into account, historical observations (where appropriate), including any calibration processes undertaken within the model (specifically whether the load forecast is matched against actual historical load on the system and substations);	The following documents explain how the historical observations of energy, customer connections and maximum demand form the basis of Ergon Energy's modelling approach. • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(h)	how the resulting forecast data is consistent across forecasts provided for each network element identified in Workbook 1 – Regulatory determination, regulatory template 5.4 and system wide forecasts;	Ergon Energy's approach has sought to reconcile forecasts between, zone substations, sub-transmission substations and connection points. This is explained in: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(i)	how the forecasts resulting from these methods and assumptions have been used in determining the following:	
17.3(i)(i)	capex forecasts; and	The maximum demand forecasts have been a key input to developing our capital expenditure programs. Specifically, Ergon Energy has used spatial demand forecasts to determine whether there may be a constraint on the network because of forecast peak demand or where retirement of an asset is required. For further information refer to:

		• Customer Reliability Strategy (Attachment 7.048), and • the DAPR (Attachment 7.050).
17.3(i)(ii)	operating and maintenance expenditure forecasts.	Ergon Energy’s Opex BST model applies a “rate of change” forecast to determine Opex in each regulatory year of the forthcoming period. The rate of change calculation uses customer number growth and maximum (ratcheted) demand forecasts. For further information refer to chapter 6 of our Regulatory Proposal
17.3(j)	whether Ergon Energy used the forecasting model(s) it used in the joint planning process for the purposes of its regulatory proposal;	For further information refer to: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(k)	whether Ergon Energy forecasts both coincident and non-coincident maximum demand at the feeder, connection point, sub-transmission substation and zone substation level, and how these forecasts reconcile with the system level forecasts (including how various assumptions that are allowed for at the system level relate to the network level forecasts);	Ergon Energy only forecasts non-coincident maximum demand at the feeder level. We forecast both non-coincident and coincident maximum demand at the connection point, sub-transmission substation and zone substations levels. Ergon Energy has explained the way they have reconciled to system level forecasts in: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001). In summary, the non-coincident zone substation forecasts were reconciled to the relevant regional maximum demand forecast for each year in the 10-year forecast period. The reconciliation process also produced coincident zone substation forecasts in MW, starting from an unreconciled estimate of coincident demand. This was based on diversity factors representing the ratio of coincident-to-non-coincident maximum demand at the zone substation.
17.3(l)	whether Ergon Energy records historic maximum demand in MW, MVA or both;	Ergon Energy records MW and MVA at connection points, sub-transmission, and zone substations. Ergon Energy only record amps for high voltage feeders; as we do not record voltage or power factor correction at this level of the network. For high voltage feeders we assume normal voltage to provide and estimated MVA value.

		• Load Forecasting Spatial Maximum Demand (Attachment 17.042) • ACIL Allen Demand Review Energy Queensland (Attachment 5.001)
17.3(m)	the probability of exceedance that Ergon Energy uses in network planning;	Ergon Energy uses 50% POE forecast to plan the network to cater for a single contingency. The 10% POE forecast is used to plan the network for system normal configuration. For further information refer to our DAPR (Attachment 7.050).
17.3(n)	the contingency planning process, in particular the process used to assess high system demand;	Refer to response in 17.3(m)
17.3(o)	how risk is managed across the network, particularly in relation to load sharing across network elements and non-network solutions to peak demand events;	Network limitations are identified using the Demand Forecast as one input. Refer to our DAPR (Attachment 7.050) for further information.
17.3(p)	whether and how the maximum demand forecasts underlying the regulatory proposal reconcile with any demand information or related planning statements published by AEMO, as well as forecasts produced by any transmission network service providers connected to Ergon Energy's network;	Please also refer to: • ACIL Allen Demand Review Energy Queensland (Attachment 5.001), and • Load Forecasting Spatial Maximum Demand (Attachment 17.042).
17.3(q)	how the normal and emergency ratings are used in determining capacity for individual zone substations and sub-transmission lines;	Ergon Energy uses emergency ratings to plan the network to cater for a single contingency. The normal ratings are used to plan the network for system normal configuration. The Plant Rating Manual articulates how these are determined. For further information refer to our DAPR (Attachment 7.050).
17.3(r)	where Ergon Energy proposes to commence or continue a demand-related capex project or program during the forthcoming regulatory control period on a HV feeder:	
17.3(r)(i)	for each feeder from the zone substation that is the connecting zone substation for the relevant HV feeder, and any other feeders that the relevant HV feeder can transfer load to or from:	

17.3(r)(i)(A)	assumed future load transfers between feeders;	Ergon Energy considers load transfers as one of the options to address an identified limitation. Refer to our DAPR (Attachment 7.050) for further information.
17.3(r)(i)(B)	assumed feeder underlying load growth rates (exclusive of transfers and specific customer developments); and	Our system and tools identify an underlying feeder growth rate exclusive of transfers and customer developments (i.e. block loads).
17.3(r)(i)(C)	assumed block loads, and associated demand assumptions;	As discussed above, block loads are considered as part of the demand forecast procedure. For further information refer to: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(r)(ii)	existing embedded generation capacity, and associated assumptions on the impact on demand levels;	This is captured through actual demand. For further information refer to: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(r)(iii)	assumed future embedded generation capacity, and associated assumptions on the impact on demand levels;	Ergon Energy's demand forecast process incorporates forecasts of household PV generation growth, and considers the likely load injected into our network from potential embedded generation. We use a probabilistic approach to determine the likely capacity. • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(r)(iv)	existing non-network solutions, and the associated assumptions on the impact on demand levels;	Demand or generation responses procured for network support are captured in Ergon Energy's planning processes to ensure future network limitations are accurately assessed. Further information on planning philosophy can be found in the Ergon Energy DAPR (Attachment 7.050).
17.3(r)(v)	assumed future non-network solutions, and associated assumptions on the impact on demand levels; and	Demand or generation responses that could be procured for future network support will be identified the planning phase for future network limitations and captured in Ergon Energy planning processes. Further information on Ergon Energy's planning

		philosophy can be found in our DAPR (Attachment 7.050).
17.3(r)(vi)	the diversity between feeders.	Sections 5.3.4, 6.4.3 and 6.12.4 of our 2018 DAPR (Attachment 7.050) and Strategic Proposal Distribution Feeder Augmentation (Attachment 7.091) details the assumptions and methodologies used to commence or continue a demand-related capex project or program during the forthcoming regulatory control period on a HV feeder.
17.3(s)	where Ergon Energy proposes to commence or continue a demand-related capex project or program during the forthcoming regulatory control period on a zone substation (or relevant substations for a sub-transmission line):	
17.3(s)(i)	assumed future load transfers between related substations;	In discussion with Network Planners, Ergon Energy determines the constraints on our zone substations, substations, and sub-transmission lines. This includes consideration of future load transfers proposed to treat identified constraints, and these are captured in the load forecast. For further information refer to: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(s)(ii)	assumed underlying load growth rates (exclusive of transfers and specific customer developments);	Underlying growth rates, exclusive of transfers and specific customer developments, are determined in SIFT. Refer to: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(s)(iii)	assumed specific customer developments, and associated demand assumptions;	Customer developments and associated demand assumptions are considered in SIFT. Further information can be found in: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(s)(iv)	existing embedded generation capacity, and associated assumptions on the impact on demand levels;	Ergon Energy’s demand forecasts also incorporate existing embedded generation capacity. Further information can be found in:

		• Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(s)(v)	assumed future embedded generation capacity, and associated assumptions on the impact on demand levels;	Ergon Energy's demand forecasts also incorporate specific customer developments. Further information can be found in: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.3(s)(vi)	existing non-network solutions, and the associated assumptions on the impact on demand levels;	Consistent with Ergon Energy's demand management policy, Ergon Energy assesses whether there are any viable and efficient non-network solutions to address the constraint on the network. Demand or generation responses procured for network support are captured in Ergon Energy's planning processes to ensure future network limitations are accurately assessed. Further information on Ergon Energy's planning philosophy can be found in the DAPR (Attachment 7.050).
17.3(s)(vii)	assumed future non-network solutions, and associated assumptions on the impact on demand levels; and	Demand or generation responses that could be procured for future network support will be identified the planning phase for future network limitations and captured in Ergon Energy planning processes. Further information on Ergon Energy's planning philosophy can be found in the DAPR (Attachment 7.050).
17.3(s)(viii)	diversity with related substations.	As part of the forecasting process we record maximum demand on each feeder, and we may be able to see diversity in the commercial and residential feeder. For further information refer to: • Load Forecasting Spatial Maximum Demand (Attachment 17.042), and • ACIL Allen Demand Review Energy Queensland (Attachment 5.001).
17.4	Provide:	
17.4(a)	evidence that any independent verifier engaged by Ergon Energy has examined the reasonableness of the method, processes and assumptions in determining the forecasts and has sufficiently capable expertise in undertaking a verification of forecasts; and	Independent review of the forecast was undertaken for this submission by ACIL Allen Consulting. This is explained in ACIL Allen Demand Review Energy Queensland (Attachment 5.001).

17.4(b)	all documentation, analysis and models evidencing the results of the independent verification.	Ergon Energy has submitted all relevant documents available from ACIL Allen. Refer to response provided in 17.4(a).
18	**EFFICIENCY BENEFIT SHARING SCHEME**	
18.1	For the purposes of applying the efficiency benefit sharing scheme:	
18.1(a)	identify all cost categories proposed to be excluded from the operation of the efficiency benefit sharing scheme;	Refer to document “Application of Incentives Schemes” (Attachment 11.002)
18.1(b)	explain for each cost category identified in the response to paragraph 18.1(a) the reasons for the proposed exclusion.	Refer to document “Application of Incentives Schemes” (Attachment 11.002)
19	**SERVICE TARGET PERFORMANCE INCENTIVE SCHEME**	
19.1	Provide Ergon Energy’s detailed methodology for calculating the following parameters used in the STPIS;	
19.1(a)	the SAIDI, SAIFI and MAIFI targets for each supply reliability area;	Refer to documents “Application of Incentives Schemes” (Attachment 11.002) and STPIS Targets and Incentive rates (Attachment 11.008).
19.1(b)	the customer service parameters and targets;	Refer to document “Application of Incentives Schemes” (Attachment 11.002)
19.1(c)	daily SAIDI, SAIFI and MAIFI and customer service performance derived from the individual interruption data under paragraph 19.3;	Refer to document “Application of Incentives Schemes” (Attachment 11.002)
19.1(d)	the MED threshold derived from the daily SAIDI data;	Refer to document “Application of Incentives Schemes” (Attachment 11.002)
19.1(e)	The incentive rates to apply to each supply reliability area.	Refer to document “Application of Incentives Schemes” (Attachment 11.002)
	Note: All calculations must be made in accordance with the STPIS and using data which complies with the STPIS definitions. Ergon	

	Energy must provide their SAIDI, SAIFI and MAIFI targets for each supply reliability area and not its forecasted SAIDI, SAIFI and MAIFI for each supply reliability area.	
19.2	If Ergon Energy proposes adjustments to the STPIS targets away from those based upon raw historical data Ergon Energy must provide, in respect of each adjustment:	
19.2(a)	the reasons for the adjustment;	Refer to document 'Application of Incentives Schemes' (Attachment 11.002)
19.2(b)	the quantum of the adjustment, and the effect of the adjustment on the targets for each of the supply reliability areas; and	Refer to document 'Application of Incentives Schemes' (Attachment 11.002)
19.2(c)	the method, basis and empirical data used as justification for the adjustment.	Refer to document 'Application of Incentives Schemes' (Attachment 11.002)
19.3	Provide the data required in Workbook 1 – Regulatory determination, regulatory templates 6.1 and 6.2.	The data required by the AER has been have provided in the 2020-25 Regulatory Determination RIN template (Attachment 17.053).
20	**PROPOSED CONTINGENT PROJECTS**	
20.1	For each contingent project proposed in the regulatory proposal, provide:	Ergon Energy has not proposed any contingent projects in our forecast capex. None of Ergon Energy's forecast capex meets the criteria or threshold for a contingent project.
20.1(a)	a description of the proposed contingent project, including reasons why Ergon Energy considers the project should be accepted as a contingent project for the forthcoming regulatory control period;	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.1(b)	the proposed contingent capex which Ergon Energy considers is reasonably required for the purpose of undertaking the proposed contingent project;	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.1(c)	the methodology used for developing that forecast and the key	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.

	assumptions that underlie it;	
20.1(d)	information that demonstrates that the undertaking of the proposed contingent project is reasonably required to meet one or more of the objectives referred to in clause 6.6A.1(b)(1) of the NER;	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.1(e)	a demonstration that the proposed contingent capex for each proposed contingent project:	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.1(e)(i)	is not included (either in part of in whole) in Ergon Energy 's proposed total forecast capex for the forthcoming regulatory control period;	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.1(e)(ii)	reasonably reflects the capex criteria, taking into account the capex factors, in the context of the proposed contingent project; and	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.1(e)(iii)	exceeds either $30 million ($nominal) or 5 per cent of Ergon Energy 's proposed annual revenue requirement for the first year of the forthcoming regulatory control period, whichever is larger amount.	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.1(f)	the proposed trigger events relating to the proposed contingent project.	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.2	For each proposed trigger event relating to the proposed contingent project referred to in paragraph 20.1(f), demonstrate:	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.2(a)	the proposed trigger event is reasonably specific and capable of objective verification;	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.2(b)	the occurrence of the proposed trigger event makes the undertaking of the proposed contingent project reasonably necessary in order to achieve any of the capex objectives;	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.

20.2(c)	the proposed trigger event generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the distribution network as a whole;	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.2(d)	the proposed trigger event is described in such terms that the occurrence of that event or condition is all that is required for the distribution determination to be amended under clause 6.6A.2 of the NER;	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.2(e)	the proposed trigger event is a condition or event, the occurrence of which is probable during the forthcoming regulatory control period, but the inclusion of capex in relation to the proposed trigger event under clause 6.5.7 of the NER is not appropriate because:	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.2(e)(i)	it is not sufficiently certain that the event or condition will occur during the forthcoming regulatory control period or if it may occur after that regulatory control period or not at all; or	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.2(e)(ii)	the costs associated with the event or condition are not sufficiently certain.	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
20.3	Provide a summary of Ergon Energy’s proposed contingent projects for the forthcoming regulatory control period, including the proposed contingent capex and trigger events for each proposed contingent project in the Workbook 1 – Regulatory determination, regulatory template 7.2.	Refer to response to 20.1. Ergon Energy is not proposing any contingent projects.
21	**REVENUES FOR STANDARD CONTROL SERVICES**	
21.1	Provide Ergon Energy’s calculation of the unsmoothed and smoothed revenues for each year of the forthcoming regulatory control period using the AER’s post-tax revenue model, which is to be submitted as part of Ergon Energy’s regulatory proposal.	The calculation of forecast unsmoothed and smoothed revenue for SCS is provided in PTRM – SCS (Attachment 8.004)

21.2	Provide details of any departure from the AER's post-tax revenue model for the calculations referred to in paragraph 21.1 and the reasons for that departure.	Ergon Energy has departed from the AER's post-tax revenue model by using the year-on-year tracking method to forecast depreciation of existing assets. This is explained in Chapter 8 of Ergon Energy's Regulatory Proposal.
22	**INDICATIVE IMPACT ON ANNUAL ELECTRICITY BILLS**	
22.1	For the purposes of calculating the impact of Ergon Energy's regulatory proposal on the annual electricity bill of typical residential and business customers in Ergon Energy, provide the data/information required in Workbook 7 – Indicative Bill Impact, regulatory template 7.6. Provide the data source for each input used for the calculation.	Ergon Energy has provided the information required in Template 7.6 in Workbook 7 – Indicative Bill Impact (Attachment 17.059). • Ergon Energy has populated Template 7.6 for two distinct scenarios, in accordance with an approach confirmed and agreed with the AER on 16 January 2019. The scenarios recognise the fact that the Ergon Energy network charges for average residential and small business customers do not form part of the retail electricity bills paid by regional Queenslanders under the Queensland Government's Uniform Tariff Policy. Ergon Energy has replicated Template 7.6 for both scenarios, and the approach set out below describes how each version of Template 7.6 has been populated. Details common to both Scenarios 1 and 2: • The source data for the annual usage per customer in Table A of 7.6.1.1 for the flat tariff is based on the average residential customer or small business customer in Ergon Energy's region, consistent with the definition use for customer impact analysis in the 2020-25 Tariff Structure Statement (Attachment 14.002) and in the Regulatory Proposal. For the TOU tariff, this annual usage per customer has been aligned with the energy usage data for a residential and small business customer on a seasonal time of use (TOU) energy tariff, as provided to the Queensland Competition Authority (QCA) and set out in the QCA's Final determination - Regulated retail electricity prices for 2018–19 (May 2018). • Note that Ergon Energy's residential and small business seasonal TOU energy tariffs (STOUE) have a peak and off-peak charging parameter. For the small business TOU tariff, it has been assumed that 10.1% of consumption occurs during peak time, with the remainder in off

		peak (which is consistent with the peak and off-peak consumption split in the QCA's Final determination - Regulated retail electricity prices for 2018–19 (May 2018) for Tariff 22A). For the residential TOU tariff, it has been assumed that 11% of consumption occurs during peak time (which is consistent with the QCA's Final Determination for Tariff 12A), with the remainder in off peak.
		• The source data for the smoothed nominal and real revenues in table 7.6.1.2 was obtained from the Ergon Energy PTRM (Attachment 8.004) submitted as part of the Regulatory Proposal • The source data for the energy delivered forecast in table 7.6.1.2 is aligned with the energy delivered data set out in the 2020-25 Reset RIN Template 3.4.1 DOPED01 • Ergon Energy notes an error in rows 61, 62, 70 and 71 whereby the real regulated tariff and real annual change calculations are incorrectly referring to the nominal regulated tariff values. These errors have been corrected in the template for Workbook 7 submitted to the AER • Between Scenarios 1 and 2, only Tables B and C of 7.6.1.1 are different – the rest of the templates are identical and as such only the differences between Tables B and C are provided below: Details specific for Scenario 1: • The source data for the annual usage per customer in Table B of 7.6.1.1 is calculated based on the QCA's notified retail price calculations as per the QCA's Final determination - Regulated retail electricity prices for 2018–19 (May 2018). This approach is as per agreement with the AER. Specifically: 　○ The retail bill has been calculated based on an "N+R" approach whereby

		○ For the flat tariff, the "N" is based on the Energex T8400 network tariff for residential customers, and the Energex T8500 network tariff for small business customers. For the TOU tariff, the "N" is based on the underlying network tariffs used by QCA for Tariff 12A for residential customers, and Tariff 22A for small business customers as per the QCA's Final determination - Regulated retail electricity prices for 2018–19 (May 2018). For the TOU tariff, these underlying network tariffs have been escalated by CPI to determine the 2019-20 network tariff values ○ For the flat tariff, the "R" is calculated using the QCA's approach and the retail, wholesale and other cost components that comprise the "R" consistent with the values and approach set out in the QCA's Final determination - Regulated retail electricity prices for 2018–19 (May 2018) for "Tariff 11" (residential) and "Tariff 20" (small business). Similarly for the TOU tariff, the "R" is calculated using the QCA's approach and the retail, wholesale and other cost components that comprise the "R" consistent with the values and approach set out in the QCA's Final determination - Regulated retail electricity prices for 2018–19 (May 2018) for "Tariff 12A" (residential) and "Tariff 22A" (small business). • The source data for the distribution costs as a proportion of a typical customer's electricity in Table C of 7.6.1.1 is calculated based on the following calculation:
		○ The network bill calculated using the Energex "N" (For the flat tariff, the T8400 network tariff for residential customers, and the Energex T8500 network tariff for small business customers, and for the TOU tariff, the underlying network tariff used by QCA for Tariff 12A for residential customers, and Tariff 22A for small business customers) is divided by ○ The total retail bill calculated and set out in Table B of 7.6.1.1

		Details specific for Scenario 2:
		
		• The source data for the annual usage per customer in Table B of 7.6.1.1 is calculated based on the QCA's notified retail price calculations as per the QCA's Final determination - Regulated retail electricity prices for 2018–19 (May 2018). This approach is as per agreement with the AER. Specifically:
		  ○ The retail bill has been calculated based on an "N+R" approach whereby
		  ○ For the flat tariff, the "N" is based on the Ergon Energy ERIBT network tariff for residential customers, and the Ergon Energy EBIBT network tariff for small business customers. For the TOU tariff, the "N" is based on the STOUE network tariff for residential customers, and the equivalent STOUE network tariff for small business customers
		  ○ For the flat tariff, the "R" is calculated using the QCA's approach and the retail, wholesale and other cost components that comprise the "R" consistent with the values and approach set out in the QCA's Final determination - Regulated retail electricity prices for 2018–19 (May 2018) for "Tariff 11" (residential) and "Tariff 20" (small business). Similarly for the TOU tariff, the "R" is calculated using the QCA's approach and the retail, wholesale and other cost components that comprise the "R" consistent with the values and approach set out in the QCA's Final determination - Regulated retail electricity prices for 2018–19 (May 2018) for "Tariff 12A" (residential) and "Tariff 22A" (small business).

		• The source data for the distribution costs as a proportion of a typical customer's electricity in Table C of 7.6.1.1 is calculated based on the following calculation: ○ The network bill calculated using the Ergon Energy "N" (For the flat

		tariff, the ERIBT network tariff for residential customers, and the Ergon Energy EBIBT network tariff for small business customers, and for the TOU tariff, the residential STOUE network tariff and small business STOUE network tariff) is divided by the total retail bill calculated and set out in Table B of 7.6.1.1
22.2	The data/information required in Workbook 7 – Indicative Bill Impact, regulatory template 7.6 is to be provided for the distribution costs of Ergon Energy and does not include any data/information in relation to any applicable transmission or jurisdictional scheme pass through costs.	Ergon Energy confirms that the data provided in Template 7.6 in Workbook 7 – Indicative Bill Impact (Attachment 17.059) is provided for the distribution costs of Ergon Energy and does not include any data/information in relation to any applicable transmission or jurisdictional scheme pass through costs.
23	**PROPOSED TARIFF STRUCTURE STATEMENT**	
23.1	Provide the model(s) used to calculate the long run marginal cost estimates in Ergon Energy's proposed tariff structure statement provided in accordance with the requirements of clauses 6.18.1A(a)(5) and 6.18.5(f) of the NER.	Refer to the 2020-25 LRMC Model (Attachment 14.009).
23.2	Provide and describe the methodology and assumptions used to prepare the long run marginal cost estimates in paragraph 23.1.	Refer to section 6.2 of Ergon Energy's TSS Explanatory Notes (Attachment 14.004).
23.3	Describe the relationship between the expenditure, demand and other inputs (as appropriate) used in the model provided under paragraph 23.1 and the expenditure, demand and other forecasts (as appropriate) provided as part of the building block proposal for the forthcoming regulatory control period.	Ergon Energy's approach to calculating long run marginal cost (LRMC) does not involve the inclusion of forecast expenditure or demand values that are used in developing the building block proposal. For details on how the cost estimates used in the LRMC calculation approach are aligned with those used in the building block proposed, refer to section 6.2 of Ergon Energy's TSS Explanatory Note (Attachment 14.004).
24.	**RATE OF RETURN FOR THE PROJECTED CAPITAL BASE**	
24.1	The Rate of Return Guideline sets out:	
24.1(a)	the AER's proposed positions on the elements for assessing the	

	rate of return including the return on equity and return on debt;	
24.1(b)	the estimation methods, financial models, market data and other evidence that the AER proposes to take into account when estimating the allowed rate of return;	
24.1(c)	the way in which the AER proposes to take into account the estimation methods, financial models, market data or other evidence.	
24.2	If Ergon Energy proposes any departures from the methods, etc. referenced in subsections 24.1(a) or (b), provide the reasons for this departure, and also provide;	Ergon Energy is not proposing any departures from the methods set out in the AER's Rate of Return Guideline.
24.2(c), (d)	a description of Ergon Energy's actual debt and equity raising costs; and an explanation of the methodology which Ergon Energy is proposing for the expenditure required to compensate for debt and equity raising costs.	Refer to Chapter 9 of Ergon Energy's Regulatory Proposal.
	Note: If the binding rate of return legislation is passed prior to the final RIN being completed and returned to the AER by Ergon Energy, the above sections (24.1 and 24.2) should be deleted and replaced by the following drafting (and followed): 24.1 The Rate of Return Guideline sets out how the rate of return will be calculated.	
25	**REGULATORY ASSET BASE**	
25.1	Provide Ergon Energy's calculation of the regulatory asset base for the relevant distribution system in respect of standard control services for each regulatory year of current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal.	Ergon Energy has provided the calculation of the RAB for SCS in each year of the regulatory control period RFM – SCS (Attachment 8.008). Ergon Energy has also used the AER's roll forward model (RFM) to calculate the RAB for ACS metering and public lighting. These calculations are set out in: • RFM – ACS metering (Attachment 15.023)

		• RFM – ACS public lighting conventional (Attachment 15.025), and • RFM – ACS Public Lighting LED (Attachment 15.027).
25.2	Provide details of each departure from the underlying methods in the AER's roll forward model for the calculation referred to in paragraph 25.1 and the reasons for that departure.	Ergon Energy is not proposing departures from the underlying methods in the AER's RFM.
25.3	If the value of the regulatory asset base as at the start of the forthcoming regulatory control period is proposed to be adjusted because of changes to asset service classification, provide details including relevant supporting information used to calculate that adjustment value.	An explanation of how the roll-forward of the RAB is calculated is provided in Chapter 8 of our Regulatory Proposal. The actual values are shown in RFM – SCS (Attachment 8.008).
25.4	Provide details of any departure in the allocation of actual capex, asset disposal and customer contribution values across asset classes in the roll forward model from those reported in the Annual Reporting RIN for the relevant regulatory years and the reasons for that departure.	Ergon Energy is not proposing any departures in the allocation of values across asset classes in the RFM from those reported in the Annual Reporting RIN.
26	**DEPRECIATION SCHEDULES**	
26.1	Provide Ergon Energy's calculation of the depreciation amounts for the relevant distribution system in respect of standard control services for each regulatory year of:	
26.1(a)	the current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal	The calculation of depreciation amounts for the current regulatory period is provided in the following models: • RFM – SCS (Attachment 8.008) • RFM – ACS metering (Attachment 15.023) • RFM – ACS public lighting conventional(Attachment 15.025), and • RFM - public lighting LED (Attachment 15.027).

26.1(b)	the forthcoming regulatory control period using the AER's post-tax revenue model, which is to be submitted as part of the regulatory proposal.	The calculation of depreciation amounts for the forthcoming regulatory period is provided in the following models: • PTRM – SCS (Attachment 8.004) • PTRM – ACS metering (Attachment 15.017) • PTRM – ACS public lighting conventional (Attachment 15.019), and • PTRM – ACS public lighting LED (Attachment 15.021).
26.2	Provide details of any departure from the underlying methods in the AER's roll forward model and post-tax revenue model for the calculations referred to in paragraph 26.1 and the reasons for that departure.	As noted in response to 25.2, Ergon Energy is not proposing any departure to the underlying methods in the RFM to the extent that they apply to the roll-forward of the RAB. As noted in response to 21.2, Ergon Energy has departed from the AER's PTRM by using the year-on-year tracking method to forecast depreciation of existing assets. This is explained this further in Chapter 8 of the Regulatory Proposal.
26.3	Identify any changes to standard asset lives for existing asset classes from the previous determination. Explain the reason(s) for each change and provide relevant supporting information.	Chapter 8 of the Regulatory Proposal provides Ergon Energy's standard asset lives. These are consistent with the previous determination.
26.4	Identify any changes to new asset classes from the previous determination. Explain the reason(s) for using these new asset classes and provide relevant supporting information on their proposed standard asset lives.	Ergon Energy is proposing an additional asset class for legacy ICT assets as set out in Chapter 8 of the Regulatory Proposal.
26.5	If any existing asset classes from the previous determination are proposed to be removed and their residual values to be reallocated to other asset classes, explain the reason(s) for the change and provide relevant supporting information. This should include a demonstration of the materiality of the change on the forecast depreciation allowance.	Ergon Energy is not proposing to remove any asset class.
26.6	Describe the method used to depreciate existing asset classes as at 1 July 2020 (the start of the forthcoming regulatory control	As noted in response to 21.2 and 26.2, Ergon Energy is proposing to adopt the

	period) and provide supporting calculations, if the approach differs from that in the roll forward model.	year on year tracking method to depreciate existing assets as at 1 July 2020.
27	**CORPORATE TAX ALLOWANCE**	
27.1	Provide Ergon Energy's calculation of the estimated cost of corporate income tax for the forthcoming regulatory control period using the AER's post-tax revenue model, which is to be submitted as part of the regulatory proposal.	Ergon Energy's corporate income tax forecast is provided in the following models: • PTRM – SCS (Attachment 8.004) • PTRM – ACS metering (Attachment 15.017) • PTRM – ACS public lighting conventional (Attachment 15.019), and • PTRM – ACS public lighting LED (attachment 15.021). Relevant calculations are explained in Chapter 10 of Ergon Energy's Regulatory Proposal.
27.2	Provide details of each departure from the AER's post-tax revenue model for the calculations referred to in paragraph 27.1 and the reasons for that departure.	Ergon Energy is proposing no departures to how the cost of corporate income tax is calculated in the AER's PTRM.
27.3	Identify each change to standard tax asset lives for existing asset classes from the previous determination. Explain the reason(s) for the change and provide relevant supporting information, including Commonwealth tax laws governing depreciation for tax purposes.	Chapter 10 of the Regulatory Proposal provides Ergon Energy's standard tax asset lives and explains any changes from previous determination
27.4	Describe the method used to depreciate existing asset classes as at 1 July 2020 (the start of the forthcoming regulatory control period) for tax purposes and provide supporting calculations, if the approach differs from that in the roll forward model.	These are identified and explained Chapter 8 of Ergon Energy's Regulatory Proposal.
27.5	Provide Ergon Energy's calculation of the tax asset base for the relevant system in respect of standard control services for each regulatory year of the current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal.	Ergon Energy has provided the calculation in the AER's RFM. Refer to RFM – SCS (Attachment 8.008).

27.6	Provide details of each departure from the underlying methods in the AER's roll forward model for the calculation referred to in paragraph 27.5 and the reasons for that departure.	Ergon Energy is proposing no departures to how the cost of corporate income tax is calculated in the AER's PTRM. Refer to PTRM – SCS (Attachment 8.004).
27.7	Identify each difference in the capitalisation of expenditure for regulatory accounting purposes and tax accounting purposes. Provide reasons and supporting calculations to reconcile any differences between the two forms of accounts.	Ergon Energy has interpreted this question as asking for any differences between how we have treated expenditure in our proposed RAB and tax asset base. Adopting this interpretation, the only difference is in the treatment of capital contributions – which are removed from the RAB, but not the tax asset base. This difference in treatment is reflected in the AER's PTRM and the AER's RFM. Refer to PTRM – SCS (Attachment 8.004), and RFM – SCS (Attachment 8.008).
28	**RELATED PARTY TRANSACTIONS**	
28.1	Identify and describe all entities which:	
28.1(a)	are a related party to Ergon Energy and contribute to the provision of distribution services by Ergon Energy; or	All related parties to Ergon Energy are identified in 'EQL Corporate Structure' document (Attachment 17.020). Energy Queensland Limited (Ergon Energy's parent entity) provides corporate support services supporting the provision of distribution services.
28.1(b)	have the capacity to determine the outcome of decisions about Ergon Energy's financial and operating policies.	Energy Queensland Limited provides the strategic oversight of Ergon Energy. For further information refer to the following documents: • 'EQL Corporate Structure - Governance and Delegations' document, (Attachment 17.021), and • 'EQL Corporate Structure -Subsidiary Board reporting and approvals' document (Attachment 17.022).
28.2	Provide a diagram of the organisational structure depicting the relationships between all the entities identified in the response to paragraph 28.1.	This is provided in 'EQL Corporate Structure' document (Attachment 17.020).

28.3	Identify:	
28.3(a)	all arrangements or contracts between Ergon Energy and any of the other entities identified in the response to paragraph 28.1 currently in place or expected to be in place during the period 2018-19 to 2024-25 which relate directly or indirectly to the provision of distribution services; and	Energy Queensland Limited has entered into the following agreements with Ergon Energy: • EQL Treasury Management Agreement (Attachment 17.031), under which Energy Queensland provides central treasury management services for the Energy Queensland Limited Corporate Group (including Ergon Energy Network and Ergon Energy Retail), in order to operate its treasury operations prudently and effectively. • EQL Framework Agreement (Attachment 17.027), which establishes a framework for the provision of resources and services between entities in the Energy Queensland Limited Corporate Group. • Energy Queensland Limited and its subsidiaries (including Ergon Energy and Ergon Retail) entered into a service schedule on 3 October 2018 that documents the provision of employees by EQL. Refer to EQL Services Agreement – Employment Model (Attachment 17.030). Note: These attachments are subject to a claim of confidentiality We anticipate that further schedules to the EQL Framework Agreement will continue to be developed. No new contracts or arrangements are expected to be in place during the period 2018-19 to 2024-25 which relate directly or indirectly to the provision of distribution services.
28.3(b)	the service or services that are the subject of each arrangement or contract.	Refer to response 28.3(a).
28.4	For each service identified in the response to paragraph 28.3(b):	
28.4(a)	provide:	
28.4(a)(i)	a description of the process used to procure the service; and	The services that are the subject of the EQL Treasury Management Agreement

		and EQL Framework Agreement for Services relate to overall management functions performed by Energy Queensland Limited as the parent entity of the Energy Queensland Limited corporate group. They are provided in support of the efficient operation of the Energy Queensland Limited group of companies in response to the Queensland Government's merger of the Ergon Energy and Ergon Energy businesses in 2016. They do not relate to the procurement of services generally offered by external providers.
28.4(a)(ii)	supporting documentation including, but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, contracts between Ergon Energy and the relevant provider.	These contracts are provided in EQL Treasury Management Agreement and EQL Framework Agreement for Services.
28.4(b)	explain:	
28.4(b)(i)	why that service is the subject of an arrangement or contract (i.e. why it is outsourced) instead of being undertaken by Ergon Energy itself;	The services that are the subject of the EQL Treasury Management Agreement and Framework Agreement for Services relate to overall management functions performed by Energy Queensland Limited as the parent entity of the Energy Queensland Limited corporate group. They are provided in support of the efficient operation of the Energy Queensland Limited group of companies in response to the Queensland Government's merger of the Ergon Energy and Ergon Energy businesses in 2016. They do not relate to the procurement of services generally offered by external providers. The Treasury Management Agreement and Framework Agreement for Services are based on a cost recovery; therefore Energy Queensland Limited does not make a profit from these agreements.
28.4(b)(ii)	whether the services procured were provided under a standalone contract or provided as part of a broader operational agreement (or similar);	Refer to response 28.4(b)(i).
28.4(b)(iii)	whether the services were procured on a genuinely competitive basis and if not, why; and	Refer to response 28.4(b)(i).

28.4(b)(iv)	whether the service (or any component thereof) was further outsourced to another provider.	Refer to response 28.4(b)(i).
29	**VEGETATION MANAGEMENT COMPLIANCE**	
29.1	Provide compliance audits of vegetation management work conducted by Ergon Energy during the current regulatory control period.	Refer to document 'Vegetation Audit Summary' (Attachment 17.064).
30	**CORPORATE STRUCTURE**	
30.1	Provide charts that set out:	
30.1(a)	the group corporate structure of which Ergon Energy is a part; and	Refer to section 6 of Ergon Energy's CAM (Attachment 6.004).
30.1(b)	the organisational structure of Ergon Energy.	Refer to section 7 of Ergon Energy's CAM (Attachment 6.004).
31	**FORECAST MAP OF DISTRIBUTION SYSTEM**	
31.1	Provide a forecast map of Ergon Energy's distribution system for the forthcoming regulatory control period. This map, together with any appropriate accompanying notes, should also indicate the location of new major network assets proposed to be constructed over the forthcoming regulatory control period.	Refer to the 'Forecast Map of Distribution System' (Attachment 17.039)
32	**TRANSITIONAL ISSUES**	
32.1	Provide information on transitional issues (expressly identified in the NER or otherwise) which Ergon Energy expects will have a material impact on it and should be considered by the AER in making its distribution determination. For each issue, set out the following information:	

32.1(a)	the transitional issue;	Ergon Energy has not identified any transitional issues.
32.1(b)	what has caused the transitional issue;	Refer to response 32.1(a) noting Ergon Energy has not identified any transitional issues.
32.1(c)	how the transitional issue impacts on Ergon Energy; and	Refer to response 32.1(a) noting Ergon Energy has not identified any transitional issues.
32.1(d)	how Ergon Energy considers the transitional issue could be addressed.	Refer to response 32.1(a) noting Ergon Energy has not identified any transitional issues.
33	**AUDIT OPINION REPORTS AND REVIEW CONCLUSION STATEMENTS**	
33.1	Provide the audit opinion report and review conclusion statements as applicable, prepared in accordance with the requirements set out in Appendix C.	Refer to Audit and Review report (Attachment 17.004).
33.2	Provide all reports from the auditor to Ergon Energy's management regarding the review conclusion statements and/or auditors' opinions report or assessment.	Refer to Audit and Review report (Attachment 17.004).
34	**CONFIDENTIAL INFORMATION**	
34.1	This clause applies to any information Ergon Energy provides:	
34.1(a)	in response to Schedule 1;	
34.1(b)	in a regulatory proposal for the forthcoming regulatory control period (a Proposal)	
34.1(c)	in a revision or amendment to a Proposal; and	

34.1(d)	in a submission Ergon Energy makes regarding a Proposal or a revised or amended Proposal; (together, Ergon Energy's Information).	
34.2	If Ergon Energy wishes to make a claim for confidentiality over any of Ergon Energy's Information, provide the details of that claim in accordance with the requirements of the AER's Confidentiality Guideline, as if it extended and applied to that claim for confidentiality.	Refer to Ergon Energy's 'Confidentiality template' (Attachment 16.002)
34.3	Provide any details of a claim for confidentiality in response to paragraph 34.2 at the same time as making the claim for confidentiality.	Refer to Ergon Energy's 'Confidentiality template' (Attachment 16.002).
35	**COMPLIANCE WITH SECTION 71YA OF THE NEL**	
35.1	Provide a statement attesting that:	
35.1(a)	Where any expenditure or cost is has been incurred or is forecast to be incurred by Ergon Energy, as a result of or incidental to a review under Division 3A – Merits review and other non-judicial review – of the NEL:	Ergon Energy has not applied for a review under Division 3A - Merits review and other non-judicial review – of the NEL and accordingly there are no expenditures or costs that have been incurred nor forecast as a result.
35.1(a)(i)	Ergon Energy has not included any of that expenditure or cost, or any part of that expenditure or cost, in its forecast capital or operating expenditures for a network revenue or pricing determination; and	Refer to response 35.1(a) - Ergon Energy has not applied for a review under Division 3A - Merits review and other non-judicial review – of the NEL.
35.1(a)(ii)	Ergon Energy has not recovered any of that expenditure or cost, or any part of that expenditure or cost, from end users; and	Refer to response 35.1(a) - Ergon Energy has not applied for a review under Division 3A - Merits review and other non-judicial review – of the NEL.
35.1(a)(iii)	Ergon Energy has not sought to pass through any of that expenditure or cost, or any part of that expenditure or cost, to end	Refer to response 35.1(a) - Ergon Energy has not applied for a review under Division 3A - Merits review and other non-judicial review – of the NEL.

	users; or	
35.1(b)	Where no expenditure or cost has been incurred or is forecast to be incurred by Ergon Energy, as a result of or incidental to a review under Division 3A – Merits review and other non-judicial review – of the NEL:	Refer response to 35.1(a) - Ergon Energy has not applied for a review under Division 3A - Merits review and other non-judicial review – of the NEL.
35.1(b)(i)	No such expenditure or cost has been incurred or is forecast to be incurred.	Refer to response 35.1(a) - Ergon Energy has not applied for a review under Division 3A - Merits review and other non-judicial review – of the NEL.
36	**IDENFITICATION OF CERTAIN COSTS IN ACTUAL CAPITAL AND OPERATING EXPENDITURE**	
36.1	For any actual capex or opex reported in response to this notice, identify any part of that expenditure which can be attributed to any expenditure or cost that Ergon Energy has incurred as a result of, or incidental to, a review under Division 3A – Merits review and other non-judicial review – of the NEL.	Refer to response 35.1(a) - Ergon Energy has not applied for a review under Division 3A - Merits review and other non-judicial review – of the NEL and accordingly there is no associated capex or opex reported in response to this notice to be identified.

Response to Section 16, Clause 16.2

Table 2: Public lighting ACS - Unit costs for current regulatory period and forecast regulatory period ($2018/19)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25
Public Lighting Brackets;Major Road	$261.59	$265.45	$270.52	$275.25	$281.44	$287.78	$287.78	$294.74	$301.87	$309.18
Public Lighting Brackets;Minor Road	$239.46	$243.00	$247.64	$251.97	$257.64	$263.44	$263.44	$269.81	$276.34	$283.03
Public Lighting Lamps;Major Road	$148.90	$151.10	$153.99	$156.68	$160.21	$163.81	$163.81	$167.77	$171.83	$175.99
Public Lighting Lamps;Minor Road	$395.69	$401.53	$409.20	$416.36	$425.73	$435.31	$435.31	$445.84	$456.63	$467.68
Public Lighting Luminaires;Major Road	$337.05	$342.02	$348.55	$354.65	$362.63	$370.79	$370.79	$379.76	$388.95	$398.36
Public Lighting Luminaires;Minor Road	$561.16	$569.44	$580.31	$590.47	$603.76	$617.34	$617.34	$632.28	$647.58	$663.25
Public Lighting Poles/Columns;Major Road	$1,193.48	$1,211.10	$1,234.22	$1,255.82	$1,284.08	$1,312.97	$1,312.97	$1,344.74	$1,377.28	$1,410.61
Public Lighting Poles/Columns;Minor Road	$364.98	$370.36	$377.43	$384.04	$392.68	$401.52	$401.52	$411.23	$421.18	$431.38
Photoelectric Cell	$8.29	$8.41	$8.57	$8.72	$8.92	$9.12	$9.12	$9.34	$9.56	$9.79

3. Material Assumptions

All material assumptions relied upon by Ergon Energy for the purposes of preparing the Regulatory Proposal have been disclosed in Table 3 below.

Table 3 provides responses to the following Schedule 1 requirement in the Reset RIN:

- 1.4(b) Provide all material assumptions
- 1.5(a) Provide the source or basis of each material assumption
- 1.5(b) If applicable, provide the assumption's quantum
- 1.5(c) Whether and how the assumption has been applied and was taken into account, and
- 1.5(d) The effect or impact of the assumption on the capital and operating expenditure forecasts in the forthcoming regulatory control period taking into account:

    (i) The actual expenditure incurred during the current regulatory control period, and

    (ii) The sensitivity of the forecast expenditure to the assumption.

Table 3: Material Assumptions

Issue	Assumption	Rationale for “reasonableness”	Source/Basis	Assurance Review	Quantum	Application	Impact sensitivity
Structure and ownership	Our forecasts are based on our current company structure and ownership arrangements.	Our forecasts reflect merger savings arising from our recent restructuring. A further restructuring or change of ownership could mean these savings are not achieved and may require changes to the CAM, and therefore the attribution or allocation of costs in our forecasts.	Our structure and ownership arrangements are set out in the CAM which has been approved by the AER.	Not necessary, because we are assuming that our current arrangements will continue.	Not able to be quantified because depends on organisational structure and its implications on allocation of shared costs.	Capex and opex	We have not undertaken sensitivity analysis, as counter-factual scenarios difficult to reasonably estimate.
Legislative and regulatory obligations	Our capex and opex forecasts are based on our current legislative and regulatory obligations and our Distribution Authority.	Our capex and opex forecasts reflect our compliance with our current obligations. Different obligations could materially change our costs.	Refer to our response provided in Workbook 1- Regulatory determination, regulatory template 7.3.	Not necessary, because we are assuming that our current obligations will not change materially.	Unable to be quantified - depends on the degree of any future legislative and regulatory changes.	Capex and opex	We have not undertaken sensitivity analysis, as counter-factual scenarios difficult to reasonably estimate.

Issue	Assumption	Rationale for "reasonableness"	Source/Basis	Assurance Review	Quantum	Application	Impact sensitivity
Service classification and ring-fencing	We will apply the service classification in the AER's Framework and Approach paper and the current ring-fencing arrangements will not change materially.	A different service classification could change our capex and opex forecast for SCS. A change in the ring-fencing arrangements could affect how we can provide our distribution services, which could potentially also change our capex and opex.	AER's Framework and Approach paper – see also chapter 4 of our Regulatory Proposal.	Not necessary, because we are applying the AER's Framework and Approach paper.	Not able to be quantified because would depend on which services would move between classifications.	Capex and opex	Not able to be estimated
Customer preferences and expectations	The preferences and expectations of participants revealed through our stakeholder engagement program accurately reflect those of our customers generally.	We have engaged effectively with a broad range of stakeholders on a broad range of matters. It is reasonable to expect that their preferences and expectations are representative of those of our broader customer base.	Refer to our customer engagement overview document and to chapter 2 of our Regulatory Proposal.	We have assessed the preferences and expectations of participants through our stakeholder engagement program and have had regard for these in preparing our Regulatory Proposals.	Unable to be quantified because customers' views have been incorporated into our forecasts – an alternative forecast has not been prepared.	Capex and opex	Not able to be estimated

Issue	Assumption	Rationale for "reasonableness"	Source/Basis	Assurance Review	Quantum	Application	Impact sensitivity
Addressing customer concerns about affordability	Our forecasts have particular regard for the affordability of electricity supply and appropriately respond to our customers' concerns.	The National Electricity Rules (NER) require us to address the concerns of consumers in developing our forecasts.	Refer to our customer engagement overview document and to chapter 2 of our Regulatory Proposal.	We have assessed the preferences and expectations of participants through our stakeholder engagement program. They have identified affordability as a key concern. We have had regard for this in preparing our Regulatory Proposals.	See chapter 14 of our Regulatory Proposal for indicative price and bill impacts.	Capex and opex	See chapter 14 of Regulatory Proposal for indicative price and bill impacts.
Service outcomes	We will maintain, but not improve, our average system-wide service outcomes, consistent with clause 6.5.6(a) and 6.5.7(a) of the NER. We will seek to improve outcomes on our worst performing feeders consistent with our regulatory obligations.	The NER does not allow the AER to approve expenditure that improves service outcomes, unless it is required by a regulatory obligation. Our expenditure forecasts reflect this requirement.	Refer to chapters 6 and 7 of our Regulatory Proposal.	Not necessary, because we are reflecting the requirements of the NER.	Unable to be quantified because have not prepared counter-factual.	Capex and opex	We have not undertaken sensitivity analysis, as counter-factual scenarios difficult to reasonably estimate.

Issue	Assumption	Rationale for “reasonableness”	Source/Basis	Assurance Review	Quantum	Application	Impact sensitivity
Forecast capex and opex	Our capex and opex forecasts are required to deliver the safety, reliability and customer outcomes set out in our Regulatory Proposal. .	Achieving our stated safety, reliability and customer outcomes depends on us delivering our proposed capex and opex program, which in turn relies upon the AER approving our forecast Annual Revenue Requirements.	Refer to chapters 6 and 7 of our Regulatory Proposal.	Our Regulatory Proposal justifies each component of our forecast Annual Revenue Requirements, including our forecast capex and opex.	See chapters 6 and 7 of our Regulatory Proposals.	Capex and opex	We have not undertaken sensitivity analysis, as counter-factual scenarios difficult to reasonably estimate.
Demand	Our base case network peak demand forecast provides an appropriate basis for our network augmentation forecast.	Our peak demand and energy forecasts have been prepared consistent with good industry practice, with independent input and verification. They provide the best view of “expected demand” for the purposes of clauses 6.5.6(a)(1) and 6.5.7(a)(1) of the NER.	Refer to chapter 5 of our Regulatory Proposal.	We engaged ACIL Allen to provide updated independent advice and recommendations on our forecasting methodology based on Industry best practice for system maximum demand, energy and customer number forecasts.	See chapter 5 of our Regulatory Proposal.	Capex and opex	Not able to be estimated.

Issue	Assumption	Rationale for "reasonableness"	Source/Basis	Assurance Review	Quantum	Application	Impact sensitivity
Customer numbers	Our base case customer number forecast provides an appropriate approach for our connections capex forecast and the customer numbers component of our opex rate of change.	Our customer number forecasts have been prepared using independently verified methodology and recommendations.	Refer to chapter 5 of our Regulatory Proposal.	We engaged ACIL Allen to provide updated independent advice and recommendations on our forecasting methodology based on Industry best practice for system maximum demand, energy and customer number forecasts.	See chapter 5 of our Regulatory Proposal.	Capex and opex	Not able to be estimated.
Cost allocation	Our CAM provides an appropriate basis for attributing and allocating costs to, and between, our distribution services.	Our CAM has been approved by the AER in accordance with the requirements of clause 6.15 of the NER, the AER's Cost Allocation Guideline and the AER's Ring-fencing Guideline.	Refer to our approved CAM and clause 6.15 of the NER, the AER's Cost Allocation Guideline and the AER's Ring-fencing Guideline.	Not necessary, because our CAM has been approved by the AER. We have applied this Method in forecasting our Annual Revenue Requirements and capex and opex.	Unable to be quantified because have not prepared counter-factual.	Capex and opex	We have not undertaken sensitivity analysis, due to difficulty in quantifying reasonable maximum and minimum.

Issue	Assumption	Rationale for “reasonableness”	Source/Basis	Assurance Review	Quantum	Application	Impact sensitivity
Unit rates/standard estimates	Unit rates/standard estimates are used in the development of our bottom up forecasts where appropriate.	Our unit rates/standard estimates provide the best view of the actual costs that we will incur.	Refer to GHD External Unit Rates Review Report (Attachment 7.004).	We have engaged GHD, an independent expert to provide advice on, and to review, our unit rates to ensure these are reasonable and reflect prudent and efficient operations.	We have not prepared any forecasts other than on the basis of our proposed CAM. For this reason, we are not in a position to identify an alternative.	Capex	Not able to be estimated
Real cost escalations for capex	Our real cost escalations used for our capex forecasts are reasonable and reflect prudent and efficient costs.	These escalations have been prepared consistent with good industry practice, with independent input and verification. They provide the best view of the actual costs that we will incur after the application of our objectives.	Attachments 6.005 and 6.006	We engaged BIS Oxford to provide advice and recommendations regarding appropriate escalation rates, and used the average of these and those calculated by the AER’s consultant Deloitte.	Attachments 6.005 and 6.006	Capex	We have not undertaken sensitivity analysis, due to difficulty in quantifying reasonable maximum and minimum.

Issue	Assumption	Rationale for "reasonableness"	Source/Basis	Assurance Review	Quantum	Application	Impact sensitivity
Inflation	Our forecast inflation is reasonable and reflects the inflation-related costs that we will incur.	Our inflation forecast reflects the AER's preferred approach to forecasting inflation, by taking the geometric mean of: • two years of forecast inflation published by the RBA in its most recent statement of monetary policy, and • eight years of forecast inflation at the midpoint of the RBA's inflation 2– 3% target, of 2.5%.	Refer to section 9.4 of our Regulatory Proposal.	Not necessary, because we are applying the AER's preferred approach to estimating forecast inflation.	See section 9.4 of our Regulatory Proposal.	Capex and opex	We have not undertaken sensitivity analysis, due to difficulty in quantifying reasonable maximum and minimum.

Issue	Assumption	Rationale for "reasonableness"	Source/Basis	Assurance Review	Quantum	Application	Impact sensitivity
Current period capex	We will deliver our forecast capex in the remainder of the current period, which will provide an appropriate basis for our capex program in the next period. Our forecast capex is less than our capex allowance for the current regulatory period.	What we spend in the next period in part depends on what we spend in the current period.	Refer to chapter 7 of our Regulatory Proposal.	Not necessary, because this reflects our assumption about what will be spent in the remainder of the current regulatory control period.	See chapter 7 of our Regulatory Proposal.	Capex	We have not undertaken sensitivity analysis, as counter-factual scenarios difficult to reasonably estimate.
New Connection Policy	We will apply our new Connection Policy.	Our Connection Policy has changed. The Connection Capex forecast reflects this new policy.	Refer to section 7.9 of our Regulatory Proposal and Attachment 7.148 for our Connection Policy	We have assessed the preferences and expectations of participants through our stakeholder engagement program and have had regard for these in preparing new Connection Policy.	See section 7.9 of our Regulatory Proposal.	Capex	We have not undertaken sensitivity analysis, due to difficulty in quantifying reasonable estimates.

Issue	Assumption	Rationale for “reasonableness”	Source/Basis	Assurance Review	Quantum	Application	Impact sensitivity
Opex base year	The financial year 2018-19 is an appropriate base year for our opex forecast and, subject to our proposed adjustments, is reasonably representative of our recurrent prudent and efficient future opex requirements.	This reflects the AER’s preferred approach to forecasting opex.	Refer to chapter 6 of our Regulatory Proposal.	Not necessary, but we have undertaken benchmarking and other assessments to demonstrate the efficiency of our 2018-19 base year.	See chapter 6 of our Regulatory Proposal.	Opex	We have not undertaken sensitivity analysis, as counter-factual scenarios difficult to reasonably estimate.
Opex trend assumptions	Our forecast changes in input costs, output growth and productivity are reasonable and appropriately reflect the trend in our future opex, given our (adjusted) opex base year.	We are applying the AER’s preferred framework to forecast these trends.	Refer to chapter 6 of our Regulatory Proposal.	Not necessary, because we used the AER’s preferred framework to forecast each component of the opex trend.	See chapter 6 of our Regulatory Proposal.	Opex	We have not undertaken sensitivity analysis, as counter-factual scenarios difficult to reasonably estimate.

Issue	Assumption	Rationale for "reasonableness"	Source/Basis	Assurance Review	Quantum	Application	Impact sensitivity
Cost pass throughs and contingent projects	The AER will approve our nominated pass through events and we will not have any contingent projects.	We have nominated several pass through events (in addition to the prescribed pass through events in the NER) and have not proposed any contingent projects. If the AER decides not to accept our nominated events, and/or decides to create one or more contingent projects, then our capex and opex forecasts would potentially need to change.	See chapter 12 of our Regulatory Proposal.	Not necessary, because any change in our capex and opex forecasts would depend on which (if any) nominated events the AER rejects and what (if any) contingent project it determines.	Unable to be quantified because depends on nature of future events.	Capex and opex	Not able to be estimated.