RIN01

Regulatory Information Notice (RIN) Response

Ausgrid

Content

INTRODUCTION

Purpose of this document

This document represents Ausgrid's written response to the Reset Regulatory Information Notice (Reset RIN), issued to Ausgrid by the AER on 30 January 2018. The purpose of this response is to address each of the requirements contained in Schedule 1 of the Reset RIN.

In addressing the requirements of Schedule 1, we have identified where information has been provided or supplemented in the documents that comprise our overall response to the Reset RIN, consisting of the following documents:

- The completed regulatory templates, as required under paragraph 1.1 of Schedule 1 and in accordance with the AER's Notice including Appendix E. This is termed "Ausgrid's completed regulatory templates". These are provided at:
  - Attachment RIN13 (Workbook 1 – Regulatory Determination)
  - Attachment RIN14 (Workbook 2 – New Category Analysis)
  - Attachment RIN15 (Workbook 3 – Recast Category Analysis)
  - Attachment RIN16 (Workbook 5 – EBSS)
  - Attachment RIN17 (Workbook 6 – CESS)

  We have not used Workbook 4 – Recast Economic Benchmarking.
- The Basis of Preparation as required in paragraph 1.3 of Schedule 1. This is termed "Ausgrid's Basis of Preparation" and has been undertaken in accordance with the additional instructions set out in Schedule 2 of the AER's notice and Appendix E. This is provided at Attachment RIN18 (Ausgrid's Basis of Preparation).
- The Audit and Review reports as required in paragraph 32 Schedule 1 of the AER's notice, and have been prepared in accordance with the requirements set out in Appendix C of the AER's notice. These are provided at RIN19 (RIN Audit Report), which is a ZIP file with the following files:
  - Ausgrid Reset RIN – ASA 805 Audit Opinion – 5 Apr 2018
  - Ausgrid Reset RIN – ASAE 3000 Review Opinion – 5 Apr 2018
  - Ausgrid Reset RIN – ASRE 2405 Review Opinion ASRE – 5 Apr 2018
- The statutory declaration as required by Appendix B of the AER's notice is provided at Attachment RIN20 (RIN Statutory Declaration).

As required by paragraph 1.4(c) of Schedule 1, we must submit a table that references each response to a paragraph in this Schedule 1, where it is provided in or as part of the regulatory proposal. In effect, this element of the Notice enables a DNSP to respond to a particular question in Schedule 1 by reference to documentation submitted as part of our regulatory proposal. Due to the size of this information, our detailed response to Question 1.4(c) is set out separately as an attachment to this document, titled Schedule 1 Response Table. This is provided at Attachment RIN02 (RIN Schedule 1 response table).

Structure of this document

Our responses to each item in Schedule 1 are set out below.

Where the answer to a Reset RIN requirement is provided as part of Ausgrid's 2019-24 regulatory proposal a reference has been provided to the relevant part of the regulatory proposal. These references fall into one of two categories:

- A chapter in Ausgrid's regulatory proposal document, denoted using a chapter reference number
- An attachment provided as part of Ausgrid's regulatory proposal denoted using an attachment reference number.

In addition, certain information in support of the answers contained in this document has been provided by way of attachments. These are denoted using a RIN attachment number and title (i.e. "RINxx (Title)").

SCHEDULE 1 RESPONSES

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 6 - CESS* attached at Appendix A, completed in accordance with:

(a) this *notice*;

(b) the instructions in the relevant Microsoft Excel Workbook attached at Appendix A;

(c) the instructions in Appendix E;

(d) the service classifications set out in the *framework and approach paper*; and

(e) *Ausgrid's cost allocation method.*

The regulatory templates, which have been completed in accordance with the above requirements, are provided at:

- Attachment RIN11 (RIN Workbook 1 – Regulatory Determination)
- Attachment RIN12 (RIN Workbook 2 – New Category Analysis)
- Attachment RIN14 (RIN Workbook 5 – EBSS)
- Attachment RIN15 (RIN Workbook 6 – CESS).

1.2 If:

(a) *Ausgrid's cost allocation method* has changed during the *current regulatory control period*, or

(b) *Ausgrid's* service classifications have changed from the *current regulatory control period*, or

(c) *Ausgrid* proposes to divert from the service classifications set out in the relevant *framework and approach paper*, or

(d) *Ausgrid* proposes to change its *cost allocation method* for the *forthcoming regulatory control period*;

such that there would be *material* changes to information previously submitted to the *AER, Ausgrid* 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.

Ausgrid has not changed its cost allocation method or service classifications during the current regulatory control period. Furthermore, it does not propose any departures from the services classifications set out in the Framework and Approach paper[1] or changes to its cost allocation methodology in the forthcoming regulatory control period such that there would be material changes to information previously submitted. Hence, we are not required to submit recast data. However Ausgrid has submitted Workbook 3, recasted Repex template 2.2 due

[1] Australian Energy Regulator, *Framework and approach, Ausgrid, Endeavour Energy and Essential Energy, Regulatory control period commencing 1 July 2019*, July 2017

to a change in mapping of certain replacement programs to revised repex asset categories. This has been audited by an external auditor.

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 *Ausgrid* has complied with this *notice* in respect of:

(a) the information in each *regulatory template* in the Microsoft Excel Workbooks attached at Appendix A; and

(b) the information prepared in accordance with the following requirements in Schedule 1 of this notice:

(i) paragraph 1.2

(ii) paragraph 5.1(a)(ii)

(iii) paragraph 8.5

(iv) paragraph 13 (13.5 and 13.6)

(v) paragraph 15 (15.2 and 15.3)

(vi) paragraph 16 (16.2-16.7, 16.10)

The basis of preparation documents, which have been prepared in accordance with the above requirements, can be found at Attachment RIN16 (Ausgrid's Basis of Preparation).

1.4 Provide material used for the purposes of preparing the *regulatory proposal*:

(a) all consultants' reports commissioned and relied upon in whole or in part;

All consultant's reports relied upon in part or full for our Regulatory Proposal are set out in the following table:

Table 1. Consultant's reports

Attachment number	Consultant	Report name
5.08	GHD	Review of spatial demand forecasts and connections forecast methodology
5.10	GHD	Review of cost benefit methodology
5.15	Nuttall Consulting	Review of repex
7.01	Frontier Economics	Ausgrid's rate of return
8.04	Sankofa Consulting	Independent appraisal of diseconomies of scale
10.04	Deloitte	LRMC methodology report
10.07	Houston Kemp	Price elasticity
10.14	Stakeholders^	Pricing Directions – A Stakeholder Perspective
RIN04	PWC	Regulatory models review final report
RIN09	BIS Oxford	Cost escalation report
RIN17	PWC	RIN audit reports

^ This report was developed by Energy Consumers Australia, Public Interest Advocacy Centre and Consumer Challenge Panel (CCP10), with input from Total Environment Centre.

(b) all *material* assumptions relied upon;

Our material assumptions are summarised in the following table.

Table 2. Material assumptions

Material Assumption	Description
1. Base year opex	We have used a 2017/18 base year operating expenditure of $440 million ($2018/19) to forecast operating expenditure for the 2019-24 regulatory period.
2. Replacement capex inputs	We have assumed that the inputs used to develop our forecast replacement capex for the 2019-24 period are efficient. These inputs comprise of: (1) internal benchmark unit costs; and (2) our forecast asset replacement volumes developed using a "condition" based assessment approach.

Our material assumptions are further detailed below in response to question 1.5.

(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 proposal*;

See Attachment RIN02 (RIN Schedule 1 Response Table).

(d) a table that references each document provided in or as part of the *regulatory proposal* and its relationship to other documents provided; and

See Attachment RIN03 (List of proposal documents) for a complete list of each attachments provided and, for each document, the relationship to other documents provided.

(e) each document identified in paragraph 1.4(d) must be given a meaningful filename in the form:

Ausgrid – [Author] – [title] – [date] – [public/confidential], where:

(i) Author is the author of the file if not *Ausgrid*, for example a consultant or other third party;

(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;

(iii) Date is a relevant date associated with the file, generally the date the document was created

(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 33 of this *notice* (confidential).

All attachments to the regulatory proposal follow this file naming format.

1.5 Provide for each *material* assumption identified in the response to paragraph 1.4(b):

(a) its source or basis;

(b) if applicable, its quantum;

(c) whether and how the assumption has been applied and was taken into account; and

(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.

Details on the material assumptions, how they were applied and the effect of the assumption are set out in the following tables.

Table 3. Material assumption 1 – 2017/18 estimated underlying opex provides a reasonable baseline for forecasting the efficient costs of achieving the opex objectives

Paragraph	Response
1.5(a)	Chapter 6 of the regulatory proposal and Attachment 6.01 (Ausgrid's proposed operating expenditure) set out how estimated underlying operating expenditure in 2017/18 has been used as the efficient base year for deriving a forecast of recurrent operating expenditure.
1.5(b)	For the regulatory proposal we have used a 2017/18 base year operating expenditure of $440 million ($2018/19) to forecast operating expenditure for the 2019-24 regulatory period.
1.5(c)	The assumption was used as the base year in applying the "base-step-trend" approach to deriving forecast operating expenditure over the 2019-24 regulatory period.
1.5(d)(i)	The assumption reflects expected underlying (or recurrent) opex in 2017/18, in line with the AER's allowance for operating expenditure in 2017/18 and, accordingly, is the key driver of the operating expenditure forecast in the forthcoming regulatory control period.
1.5(d)(ii)	The forecast opex proposed by Ausgrid for the 2019-24 period is very sensitive to the assumption regarding the base year; for example, a +/-1% adjustment to the base year results in a +/-$24 million (or +/-0.996%) change in the operating expenditure forecast for the 2019-24 regulatory period.

Table 4. Material assumption 2 – We have assumed that the inputs used to develop our forecast replacement capex for the 2019-24 period are efficient. These inputs comprise of: (1) internal benchmark unit costs; and (2) our forecast asset replacement volumes developed using a "condition" based assessment approach.

Paragraph	Response
1.5(a)	The basis of this assumption rests with a comparison of our proposed replacement capex against what our forecast – hypothetically – would be if alternative inputs were applied. This comparison is set out in the following table. The "Repex Model" scenario utilises advice from Nuttall Consulting regarding Ausgrid's forecast 2019-24 replacement capex (repex) based on external benchmark unit costs and an "age based" approach to estimating replacement volumes. Nuttall Consulting's full advice is provided at Attachment 5.15.
1.5(b)	The quantum of our assumption can be estimated from the comparison in the following table. Specifically, our assumption regarding the efficiency of the inputs into our replacement capex leads to a capex forecast that is $176 million lower over the 2019-24 regulatory period. This is compared to a forecast based on a "Repex Modelling" scenario using external benchmark unit costs and a three year calibration of asset lives to estimate replacement volumes.
1.5(c)	We have applied our assumption by using our internal benchmark unit costs and our condition based approach to replacement volumes as inputs into the Business Planning Consolidation (BPC) tool that Ausgrid utilises to forecast our replacement capex for the 2019-24 regulatory period.

Paragraph	Response
1.5(d)(i)	Taking the actual expenditure incurred during the current regulatory period into account, the assumption that the inputs into our replacement forecast are efficient will have an effect or impact on our capex in the forthcoming regulatory period, but no direct effect or impact on opex.
1.5(d)(ii)	The sensitivity of our assumption to forecast capex is material. As noted, it results in a $176 million (or 5.7%) lower replacement capex forecast compared to if the approach in the above Repex Model scenario was applied.

Table 5. Quantum of material assumption 2

Scenario	Approach	Forecast assessable repex 2019-24 ($m, real FY19)
Ausgrid forecast repex (assessable components)	Internal benchmark unit costs and condition based approach to replacement volumes	1,107
Repex Model scenario	Repex model – Forecast Benchmark Unit Costs / 3 Year Calibrated Lives (FY15 to FY17)	1,283
Difference	**-**	**176**

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*.

The reconciliation is provided in the following table.

Table 6. Reconciliation ($000s, real FY19)

Ausgrid
PTRM and RIN template reconciliation
FY20 to FY24

Capex $'000							
SCS	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**Total**	**Variance %**
RIN template 2.1.1 SCS Capex	711,742	697,909	618,463	611,595	596,812	3,236,520	
PTRM - Dx inputs capex (row 71)	711,742	697,909	618,463	611,595	596,812	3,236,520	
Variance	0	0	0	0	0	0	0.00%
Dual function assets	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**Total**	**Variance %**
RIN template 2.1.5 Dual function assets capex	79,173	68,774	80,082	100,953	103,204	432,186	
PTRM - Tx inputs capex (row 71)	79,172	68,774	80,082	100,953	103,204	432,185	
Variance	0	0	0	0	0	0	0.00%
Capcons	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**Total**	**Variance %**
RIN template 2.1.7 SCS Capcons	103,201	119,627	118,558	136,230	107,401	585,017	
PTRM - Dx capcons (row 139)	103,201	119,627	118,558	136,230	107,401	585,017	
Variance	0	0	0	0	0	0	0.00%

Opex $'000							
SCS	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**Total**	**Variance %**
RIN template 2.16.1 SCS Opex	434,465	441,637	451,081	459,406	466,124	2,252,713	
PTRM - Dx opex (row 187)	434,465	441,637	451,081	459,406	466,124	2,252,713	
Variance	0	0	0	0	0	0	0.00%
Dual function assets	**2019-20**	**2020-21**	**2021-22**	**2022-23**	**2023-24**	**Total**	**Variance %**
RIN template 2.16.3 Dual function assets Opex	36,615	37,217	38,002	38,703	39,281	189,818	
PTRM - Tx opex (row 187)	36,615	37,217	38,002	38,703	39,281	189,818	
Variance	0	0	0	0	0	0	0.00%

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:

(a) the reasons for the variation or departure, including why it is appropriate;

(b) how the variation or departure aligns with the objectives of the relevant scheme; and

(c) how the proposed variation or departure will impact the operation of the relevant scheme.

Ausgrid has not departed from the framework and approach paper for the application of the efficiency benefit sharing scheme (EBSS), demand management incentive scheme (DMIS) and capital expenditure sharing scheme (CESS).

Ausgrid has departed from the framework and approach for the service target performance incentive scheme (STPIS). We have calculated our target for the telephone answering parameter based on actual performance over the last three regulatory years, instead of the last five regulatory years specified under clause 5.3.1(a) of the STPIS Guideline.

There are two main reasons for the departure. First, our call centre performance was aided in 2012/13 to 2014/15 by our ability to transfer calls to the retail line of our business under our Transitional Services Agreement (TSA). These regulatory years should therefore be excluded to obtain a true picture of Ausgrid's actual performance without the aid of the retail call centre.

Second, while providing a telephone answering service is still essential for many customers, increasingly customers expect to be able to find the information they need online. Further, our stakeholders are concerned that the number of telephone calls answered within 30 seconds is not a meaningful customer service metric. As discussed in Attachment 9.01 (Application of Incentive Schemes), we are working with our stakeholders to develop a new, more meaningful target.

The proposed variation aligns with objectives of the STPIS as Ausgrid will not be incentivised to invest in additional resources, at additional costs to our customers, to support a service that is declining in use. In terms of impact, our proposed departure arrives at a target of 80% of calls answered within 30 seconds.

Further information on the application of the incentive schemes is provided in Attachment 9.01 (Application of incentive schemes).

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:

(a) **the reasons for the departure, including why the proposed service classification is more appropriate; and**

(b) **how service will differ under the proposed service classification in comparison to that in the *framework and approach paper*.**

Ausgrid has not departed from the service classifications set out in the framework and approach. See Attachment 11.01 (Ausgrid's classification proposal) for proposed minor amendments to descriptions of services.

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*:

(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 incorporate the proposed service classifications; and**

(b) **identify and explain where the *regulatory templates* differ.**

Not applicable as Ausgrid has not proposed any amendments to the service classifications.

3. CONTROL MECHANISMS

3.1 For the forecast revenues that *Ausgrid* proposes to recover from providing *direct control services* over the *forthcoming regulatory control period* provide:

(a) **formulaic expressions for the basis of control mechanisms for standard control services and for alternative control services; and**

(b) **a detailed explanation and justification for each component that makes up the formulaic expression.**

See Attachment 4.06 (Control Mechanism for SCS and ACS).

3.2 Also demonstrate:

(a) **how *Ausgrid* considers the control mechanisms are compliant with the *framework and approach paper*; and**

(b) **for *standard control services*, how *Ausgrid* considers the control mechanisms are also compliant with clause 6.2.6 and Part C of Chapter 6 of the *NER*.**

See Attachment 4.06 (Control Mechanism for SCS and ACS).

EXPENDITURE REPORTING

4. CAPITAL EXPENDITURE

General

4.1 Provide justification for *Ausgrid's* total *forecast capex,* including the following information:

(a) **why the total *forecast capex* is required for Ausgrid to achieve each of the objectives in clause 6.5.7(a) of the *NER*;**

(b) **how *Ausgrid's* total *forecast capex* reasonably reflects each of the criteria in clause 6.5.7(c) of the *NER*;**

(c) **how *Ausgrid's* total *forecast capex* accounts for the factors in clause 6.5.7(e) of the *NER*;**

Clause 6.5.7 of the Rules requires the AER to consider whether a DNSP's proposed capex meets the capex objectives, and is consistent with the capex criteria with regard to the capex factors.

Our proposed total forecast capital expenditure (capex) of $3.1 billion reflects the activities we consider necessary to achieve the expenditure objectives listed in clause 6.5.7(a) of the National Electricity Rules (Rules or NER). In summary, capex objectives are:

- Meet or manage the expected demand for standard control services (objective 1).
- Comply with all applicable regulatory obligations or requirements (objective 2)
- Maintain the quality, reliability and security of supply of standard control services and of the distribution system through the supply of standard control services (objective 3)
- Maintain the safety of the distribution system through the supply of standard control services (objective 4).

Our proposed capex program of $3.1 billion for the 2019-24 period is 1.3% lower than the amount we expect to invest in the current 2014-19 regulatory period, but remains 69% below the peak capex in 2012. We achieved these reductions, in part, through initiatives including:

- Introducing a more rigorous cost-benefit analysis that deferred major projects where it was efficient to do so
- Avoiding 'like-for-like' replacement of major infrastructure by utilising spare capacity on neighbouring parts of the network
- Increasing our focus on demand management solutions to defer replacement capex
- Outsourcing more of the capital program to external providers where there was a cost advantage of doing so
- Improving our governance processes to better target our investment and ensures projects are scoped and costed efficiently at each stage of the investment cycle through planning, design and delivery.

These improvements and efficiency gains are now embedded in the business, and in our capex forecasts for the 2019-24 period. The improvements will reduce ongoing costs and we will make sure that they do not adversely impact on the reliability, security and safety of our services.

In forecasting our capital expenditure requirements, we must achieve an appropriate balance between the pressure to reduce expenditure further and the importance of maintaining safety and service performance whilst managing network risks efficiently, both now and in the future. For the reasons set out in Chapter 5 of our Regulatory Proposal, we believe that we have achieved an appropriate balance.

In preparing our capex forecasts we have grouped our proposed capital programs and projects to align with the AER's expenditure assessment categories for capex.

Table 7 provides a summary of the expenditure categories underpinning our capex forecast, and describes the key activities related to each expenditure category and how these activities relate to the expenditure objectives.

Table 7. Description of activities by capex categories

Capex cost categories	Activities and relevance to capital expenditure objectives
Replacement programs	Consists of activities involving the replacement of existing assets that pose unacceptable safety, reliability, security or environmental risks. These activities and their associated costs relate to achieving capex objectives 2, 3 and 4.
Growth related capital programs	These programs relate to connection and augmentation activities that are aimed at ensuring customers access to our network and meeting demand and maintaining security, reliability and quality of supply. These activities therefore relate to meeting capex objectives 1-3.
Non-network related programs	This expenditure category relates to costs associated with ICT, non-network OTI and innovation, non-network property, fleet and plant. It includes the underlying technology required to operate and manage our electricity network, and activities to support our network, meet corporate obligations or drive efficiency. Therefore, the activities in this expenditure category relate to meeting all of the capex objectives.
Capital support programs	Capital program support costs (capitalised overheads and network overheads) make up the overhead costs that support the efficient delivery of the capital program. These costs are made up of direct costs (network planning) and indirect costs (network divisional management and business support functions; fleet; corporate support functions; logistics, warehousing and procurement; and IT). (Note these are different costs to non-network ICT and fleet discussed above).

Meeting the capex objectives (clause 6.5.7(a) of NER)

We consider that our capex forecast meets the capex expenditure objectives. The reasons have been set out in the below table.

Table 8. Summary of compliance with the capex objectives

<table>
<tr><th>Rule reference</th><th>Capex Objective</th><th>Addressed by</th></tr>
<tr><td rowspan="2">6.5.7(a)(1)</td><td rowspan="2">Meet or manage the expected demand for standard control services</td><td>Our forecast expenditure for growth capex incorporates growth effects of peak demand, consumption, and customer demand through the use of spatial demand forecasting. We have used spatial demand forecasting as a key input into developing our capital expenditure program (see Attachment 5.07) and have had our forecasting methodology independently reviewed to verify the veracity and robustness of our demand and customer connection forecasts (see Attachment 5.08), which incorporate the results from our maximum demand and connections forecasting models.</td></tr>
<tr><td>For replacement expenditure forecasts we have conducted detailed analysis on the condition and age of our assets to determine the most appropriate means for maintaining our network to meet demand and maintain the reliability, security and quality of electricity supply to our customers given our ageing asset profiles.</td></tr>
<tr><td>6.5.7(a)(2)</td><td>Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services</td><td>We have assessed our current compliance process against our obligations to identify whether any expenditure related to corrective action is required. In preparing our capex forecast we have sought to identify any new obligations, or changes to existing obligations, and have also considered how foreseeable changes to our operating environment during the 2019-24 period may impact on our compliance obligations. Chapter 5 of our proposal and Attachment 5.01 set out our identification of the key capital expenditure drivers for the 2019-24 period and how they have been reflected in our capex forecast.</td></tr>
<tr><td>6.5.7(a)(3)</td><td>Maintain the quality, reliability and security of supply of standard control services</td><td rowspan="2">In developing our forecast total capex we examined investment drivers at a high level by assessing the condition of our network, peak demand growth by location and need for non-network investment in ICT, property and fleet. Based on these drivers we identified replacement, augmentation, connection and non-network projects required to meet out regulatory obligations and maintain reliability, security and quality supply.
Further information on our identification of investment needs, and process for selecting the most efficient option for addressing the need is outlined in justification for project business cases in the following attachments:
• 5.13 Project justification for replacement and duty of care programs (including OTI and ADMS)
• 5.14 Project justification for 11kV switchgear, 33kV switchgear and sub transmission cables replacement
• 5.16 Project justifications for major augmentation and connections projects
• 5.19 ICT Project Justifications (excluding ADMS)
• 5.21 Non-network Property Business Cases.
We have consolidated and prioritised our ten-year capex portfolio to arrive at our total forecast capex by applying top down checks such, as the AER's repex model and trend analysis (see Attachment RIN05 (Repex description) and Attachment 5.15 (Nuttall review of repex model) risk ranking tools (see Attachment 5.04 (Prioritisation Investment Plan (PIP) process description)) and have assessed our ability to deliver our proposed capex forecast (see Attachment 5.12 (Resourcing and delivery strategy for 2019-24 period)).
Safety is a key driver in developing replacement programs. We</td></tr>
<tr><td>6.5.7(a)(4)</td><td>Maintain the safety and security of the distribution system through the supply of standard control services.</td></tr>
</table>

Rule reference	Capex Objective	Addressed by
		need to meet legislative requirements to eliminate safety risks 'so far as is reasonably practicable'. The replacement capex program has been prepared according to this key principle.

Meeting capex criteria (clause 6.5.7(c) of NER)

The AER is required to make a decision on whether to accept or reject our total forecast capex. The AER must accept the total capex forecast if it is satisfied that the forecast of required capex reasonably reflects each of the capex criteria.

At a high level, Chapter 5 of our Regulatory Proposal and Attachment 5.01 (Ausgrid's forecast capital expenditure) provides the AER with information that demonstrates the prudence of our process. This includes:

- Demonstrating that we have a 'fit for purpose' capital planning approach that is based on sound asset management principles and prudent governance frameworks. (Further information on our approach to capital planning and governance can be found at Attachments 5.03, 5.04 and 5.05).
- Identifying key inputs to our forecast, and showing how our process reflects a prudent and efficient approach. This includes our demand forecasts, unit costs, escalation, and cost benefit analysis.
- Providing justification documents for material programs and projects that demonstrate the manner in which we have assessed needs, options (including opex/capex substitution and demand management) and timing considerations when developing our programs in practice. As listed in the above table, we have prepared project justification for all of the replacement capex programs, non-network property and non-network ICT.
- Showing how we incorporated customer and stakeholder expectations in our capex forecast in relation to price affordability, and maintaining current levels of safety and reliability. It also includes specific changes to our inputs such as Value of Customer Reliability used in our capital planning process for major projects. This is set out in our regulatory proposal document.

We have also undertaken a number of partial checks of our forecast including:

- Using relevant industry benchmarks to test our proposed capex forecast. This includes testing our replacement program with the results of the AER's repex model (refer to attachment 5.11). We also applied AER partial indicators to assess our capex efficiency relative to other DNSPs (refer to section 5.2 of the Regulatory Proposal).
- Comparing our demand forecasts with AEMO's system level, and have tried to reconcile the reasons for any difference (refer to attachments 5.07 and 5.08).
- Using expert advice on industry/ economy benchmarks to establish our real cost escalators.
- Assessing whether the program and projects can be delivered in practice (refer to attachments 5.12).
- Seeking expert advice on our processes and programs. For example, we engaged GHD to assess our probabilistic planning approach (including cost benefit analysis) and peak demand forecasts (refer to attachments 5.08 and 5.10).

Meeting the capex factors (clause 6.5.7(c) of NER)

In deciding whether or not the AER is satisfied the proposed capex program meets the criteria, it must also take into account the capital expenditure factors. A summary of how our capex forecast meets the expenditure factors is outlined below in Table 9.

Table 9. Summary of how Ausgrid meets the expenditure factors

Rule reference	Capex Factor	Addressed by
6.5.7(e)(1)	(Deleted)	Not applicable
6.5.7(e)(2)	(Deleted)	Not applicable
6.5.7(e)(3)	(Deleted)	Not applicable
6.5.7(e)(4)	The most recent annual benchmarking report that has been published under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant regulatory control period.	We have carefully reviewed the AER's most recent annual benchmarking report and other relevant measures of benchmark capex that would be incurred by an efficient distribution network service provider (DNSP). We have addressed our relative performance to the AER's 2017 Annual Benchmarking Report in Chapter 5 of the Regulatory Proposal. Our latest SAIFI results show that we are the third best performer in the NEM for this metric.
6.5.7(e)(5)	The actual and expected capital expenditure of the Distribution Network Service Provider during any preceding regulatory control periods.	Chapter 5 of the Regulatory Proposal and Attachment 5.01 (Ausgrid's forecast capital expenditure) detail our actual and estimated capital expenditure for the 2014-19 regulatory period and explains the key reasons for variances between Ausgrid's actual and estimated expenditure during the current period from the AER's allowance.
6.5.7(e)(5A)	The extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the Distribution Network Service Provider in the course of its engagement with electricity consumers.	We have proactively engaged with our customers to understand their concerns. Chapter 2 of our regulatory proposal sets out our key findings from our customer engagement activities, while Attachment 2.01 and 2.02 set out our engagement approach and how Ausgrid has embedded in customer engagement as part of its business as usual activities. Chapter 5 of our proposal sets out how we have sought to reflect customer feedback in our capital expenditure forecast.
6.5.7(e)(6)	The relative prices of operating and capital inputs.	For forecast capex, the methodologies used to develop our unit costs include • Bottom up estimates – this approach uses cost components to estimate projects through an aggregation process based on the scope of work. Our estimating systems are in-line with industry best practice and rely on data that is constantly updated and validated. • Historical estimates – this has been justified where past costs were proven to be efficient and where it is not practical to rely on bottom up estimates due to unknown variability between projects. Further information on our unit cost methodologies is contained in Attachment 5.06 (Unit cost methodology). We have also undertaken an external review of our unit costs (see Attachment 5.15 (Nuttall review of repex)) to assess the efficiency of our costs, and have applied real cost escalators to labour, material and contract services to develop a reasonable estimate of the costs of undertaking projects.
6.5.7(e)(7)	The substitution possibilities	We have considered the substitution possibilities in

Rule reference	Capex Factor	Addressed by
	between operating and capital expenditure.	developing our forecast capex. A key step in our network investment planning process is to consider a full range of alternative options, including whether there may be an opex solution that is more efficient in addressing the investment need. For example, our capital planning process explicitly considers the following opex substitution possibilities: • Growth – the primary opex substitution for customer and demand driven capex is demand management. Our processes directly consider whether there is a specific demand management opportunity, or whether historical experience indicates that demand management may prove more cost effective in addressing the issues. Our proposal includes a step change in relation to demand management as result of an identified capex trade-off (see Attachment 6.01 (Ausgrid's forecast operating expenditure)). • Replacement capex – the primary opex substitute is network maintenance. Our process for deriving the timing and need for replacement considers whether there is a less costly maintenance option (see Attachment 5.01 (Ausgrid's forecast capital expenditure)). • Reliability performance capex – a means for remedying reliability may be for an opex solution such as corrective maintenance. We have considered these alternative options when developing our reliability compliance plan. • Network support – opex substitutions are a key consideration in our process for deriving replacement and new non-system capex. Our strategies also consider whether more generally whether it is better to maintain an existing function through capex or opex. This includes decisions on whether the main buildings (opex) or upgrade through capex. In ICT we are moving to the cloud (which is opex) which will reduce our capex requirements. (See Chapter 5 and Attachment 5.01 (Ausgrid's forecast capital expenditure)). In addition, we have considered the consequential impact on forecast opex from the following capex investment interactions: • The impact of capex of system capex on inspection maintenance costs – the cost of routine inspection is dependent on the volume of inspections, which is determined based on the number of assets impacted by the forecast replacement and capacity investment programs for the 2019-24 period. • Property capital investment and statutory charges – capital investment on property acquisitions has a corresponding impact on the amount of land tax paid which is an opex expense.

Rule reference	Capex Factor	Addressed by
6.5.7(e)(8)	Whether the capital expenditure forecast is consistent with any incentive scheme or schemes that apply to the Distribution Network Service Provider under clauses 6.5.8 or 6.6.2 to 6.6.4.	The regulatory framework coupled with our private ownership and customers' expectations provide strong incentives for Ausgrid to act prudently and efficiently when assessing our expenditure needs for the forthcoming regulatory period. The significant incentive schemes that our capex forecast considers include: • CESS – this scheme will provide us with additional and consistent incentives to continuously reduce our capital costs to deliver lower prices for our customers. • STPIS – this scheme will help us maintain and improve our service performance and ultimately deliver better outcomes for customers. Our forecasts include no capital expenditure to fund improvements in our levels of reliability, only to maintain reliability. The STPIS self-funding mechanism incentivises use appropriately in this regard.
6.5.7(e)(9)	The extent the capital expenditure forecast is referable to arrangements with a person other than the Distribution Network Service Provider that, in the opinion of the AER, do not reflect arm's length terms.	There will be some capex attributable to a related party (PlusES Partnership) where they undertake metering works (for standard control services) in Ausgrid substations. This is subject to an agreement that reflects commercial arm's length terms.
6.5.7(e)(9A)	Whether the capital expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b).	Our proposed capex does not include an amount relating to a project that should be more appropriately included as a contingent project under clause 6.6A1(b).
6.5.7(e)(10)	The extent the Distribution Network Service Provider has considered, and made provision for, efficient and prudent non-network options	We have published a Demand Management Engagement Strategy (see Attachment RIN07) which sets out our framework and processes for assessing non-network solutions to address a current or future constraint. Consistent with this strategy, we will continue to examine the relative merits of network, and non-network alternatives in making our expenditure decisions. Non-network alternatives will be pursued where they provide the best solution in the circumstances to address the identified need. For the 2019-24 regulatory period, demand management has been found to be the preferred option for six replacement capex projects and a high voltage augmentation program. This will result in deferred capital expenditure of around $66.1 million; however, in order to achieve those capital savings, we must spend an additional $26.1 million in opex over the period to procure the required demand response.
6.5.7(e)(11)	Any relevant final project assessment report (as defined in clause 5.10.2) published under clause 5.17.4(o), (p) or (s).	Our forecast process identified that there have been no final project assessment reports at the time of submitting this proposal.

Rule reference	Capex Factor	Addressed by
6.5.7(e)(12)	Any other factor the AER considers relevant and which the AER has notified the Distribution Network Service Provider in writing, prior to the submission of its revised regulatory proposal under clause 6.10.3, is an operating expenditure factor.	The AER did not notify Ausgrid of any factor, in addition to the factors listed in clause 6.5.7(e) that it considers relevant.

We are confident that the information presented in this proposal demonstrates that our capital expenditure forecasts reflect efficient and prudent costs, in accordance with the requirements of the Rules.

(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

Plans

We have identified our capital planning processes in our response to template 7.1. We have used our "business as usual" capital plans to identify projects and programs for the 2019-24 regulatory period. Each capital plan relates to a specific part of the network or a specific driver of investment. **Error! Reference source not found.** describes each plan and shows which AER category of capex to which it relates.

Table 10. Description of capital plans and alignment to AER capex categories

Key input	Description	Replacement	Growth	Non-network
Area Plans	We identify major projects for our sub-transmission network based on analysis of drivers such as asset condition, local peak demand growth and major customer connection activity.	✓	✓	
Replacement Plans	We identify replacement programs for distribution assets and piecemeal elements of our sub-transmission network (which are not covered by Area Plans) based on asset condition.	✓		
Distribution Capacity Plans	We identify augmentation and connection capex for the 11kV (high voltage) and low voltage network based on local peak demand growth, and ability to meet reliability licence conditions.		✓	
Non-network Plans	We identify IT, property, fleet and plant programs based on assessment of compliance obligations, and need to support business activities in an efficient way.			✓

Our planning approaches reflect a business case assessment of need, analysis of options and timing, and costing. For major projects, our business case assessment is extensive and detailed. We examine the condition of individual assets on the sub-transmission network including probability of failure and current performance, examine peak demand growth at the zone, and identify how major connections impact the development of the sub-transmission network.

We examine all feasible options, including non-capex solutions such as corrective maintenance. We specifically consider whether demand management can defer the timing of individual projects. This includes for replacement capex where we consider if demand management can be used to mitigate reliability incidents, and consequently defer the timing of projects.

As part of the consolidation process we aggregate the plans to provide a holistic view of all capital programs and projects. We then adjust the projects and programs based on high level checks such as past trend and driver analysis, and comparing outcomes to the AER's repex model.

Finally, we examine opportunities to prioritise the portfolio of projects using the Prioritisation Investment Plan (PIP). This involves using our established prioritisation methodology termed "CASH" to prioritise our 2019-24 capital forecasts. The CASH methodology assesses and ranks projects according to the level of associated risk. For our 2019-24 proposal we have used the results of the CASH process to develop the final PIP that is used as an input for deriving the forecast capex for the 2019-24 period.

Further information on the plans in our forecast method is outlined Attachments 5.01, 5.03, 5.04 and 5.05.

Policies and procedures

Template 7.1 of the regulatory templates has identified each of the types of policies and procedures and strategies that we have at Ausgrid. These strategies influence planning approaches and expenditure decisions we make at Ausgrid, and have been pivotal to the manner in which we have developed our capex forecasts for the 2014-19 period. These include:

- Governance frameworks – Our governance frameworks ensure there are clear accountabilities and delegations for decisions by Ausgrid's Board, CEO and Executive staff. This provides assurance that the relevant approvals underlie our proposed capex for the 2019-24 regulatory period.
- Accounting policies – These provide assurance that we capture and record costs we incur on the network in accordance with accounting standards. These have been instrumental in ensuring that our forecasts have allocated costs properly to standard control services, and that the cost relates to a capex rather than opex activity. For example our capitalisation policy provides clear guidance on what constitutes expenditure of a capital nature.
- Asset Management policies – The purpose of Ausgrid's asset management policy is to set out principles that the company will apply to asset management to achieve the corporate objectives. It sets out the commitments and expectations for decisions, activities and behaviours that underpin the company's asset management processes and activities. The policy provides a common set of principles that are endorsed by senior leaders and management, which can be concisely communicated and adopted by employees and external parties. These principles have been reflected in our decision making.
- Capital approval policies and processes – These provides the appropriate checks and balances to support efficient and prudent investment decisions. This provides a level of assurance that our 2019-24 proposed capex projects and programs will proceed in an efficient and prudent manner at the time of investment. Ausgrid's capex approval

processes also demonstrate that we have an effective governance process underlying our investment decisions.

- Network planning and standards – Network planning standards provide the framework for assessing need and options underlying our investment decisions. We have used these standards to identify capital programs and projects contained in the 2019-24 capex forecast. Network standards specify design and construction standards, while technical standards relate to work practices including qualifications and experience for working safely on the network. These influenced the scope of projects and programs included in the 2019-24 capital forecast.
- Asset security and disaster recovery – These policies ensure that Ausgrid keeps its assets safe from sabotage and can continue to provide services in the event of disasters. In the absence of these policies, Ausgrid's capex could be of a far higher magnitude over the 2019-24 period.
- Procurement policies – This document sets out minimum standards for the procurement of goods, stores, materials, equipment, works and services as well as the disposal of obsolete or surplus goods, stores, materials and equipment. It ensures that Ausgrid seeks all opportunities to efficiently reduce the capital costs we incur in providing services, through practices such as securing the lowest rates on electrical equipment.
- IT policies – These provide guidance on the systems that are required to ensure that we continue to provide support to meet our network and corporate functions in an efficient manner.

Regulatory obligations

We have identified our regulatory obligations in Template 7.3 of the RIN. Our obligations and requirements influence why and when we need to incur expenditure. As an electricity provider, we are subject to a range of industry specific obligations regulations that set out the manner in which we supply electricity in the Australian National Electricity Market. These regulations include the Electricity Supply Act 1995 (NSW) and Regulations made under it, the National Electricity Law (NEL) and Rules and the National Energy Retail Law and Rules. For example:

- The Electricity Supply Act imposes performance requirements for our network. It includes a requirement us to hold a DNSP licence, which in term imposes conditions in respect reliability and performance of the network. For example, our NSW Government mandated licence conditions require us to comply with a minimum average level of reliability for segments of our network, together with a minimum performance level for individual feeders.
- The National Energy Retail Law and Rules introduced in NSW from 1 July 2013 impose requirements to connect customers, customer connection contracts, guaranteed customer service standards and a range of customer rights and protections including notification of planned interruptions, disconnection processes and managing customer complaints.
- The NEL and Rules regulate Ausgrid's participation in the National Electricity Market as a Network Service Provider (both and TNSP and DNSP) and cover a range of matters including system and network reliability and security, network planning, connections procedures, and system and network standards.

Ausgrid is also subject to more general obligations and requirements which direct the way we design and operate the network. These obligations are mainly concerned with environmental protection, and public and worker safety. These influence our drivers of investment, for example, we may replace an asset if the safety consequences to our workforce or the general public cannot be appropriately mitigated through maintenance. The standards also influence our construction and designs, for instance by adhering to environmental, planning and heritage legislation.

In addition to our key role of providing electricity services, we are also required to meet our obligations as a corporation in respect of governance and financial accountability. These can drive the need for investment in IT and financial systems, and non-system property to house staff performing these functions.

As a prudent DNSP, Ausgrid also adheres to codes and guidelines that provide direction on how to meet our overriding obligation to operate our network in accordance with good electricity industry practices. Often these programs will influence our decisions to invest in replacing an asset, or on the construction standard that we apply.

(e) an explanation of how each response provided to paragraph 4.1 (a) to (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.

Our proposed capex of $1.3 billion for 2019-24 is 1.3% lower than the actual expenditure for 2015-19. The variance in the actual and forecast expenditure by asset category is presented in the table below.

Table 11. Variance in actual and forecast capex

Category	FY15-19	FY20-24	Variance	Variance %
Replacement	1,757	1,673	-84	-4.8%
Growth[2]	164	241	77	46.8%
Non-network	470	548	78	16.6%
Capital program support	732	621	-111	-15.1%
Total	**3,123**	**3,084**	**-39**	**-1.3%**

For replacement expenditure, we are proposing decrease of 5% compared to the current period. The mix of programs in our overall portfolio is shifting as a result of the following drivers:

- We are investing less on major projects in the sub-transmission network, and more on smaller assets on the distribution network. In part, this is due to large volumes of smaller assets on the network beyond 50 years of age. If we were to continue current levels of capex, we could be at risk of runaway failures, leading to cascading reliability. In contrast, we will incur less on our sub-transmission network as we find innovative ways to defer large investment or retire (rather than replace) assets.
- We are catering for a changing energy landscape characterised by higher levels of renewable energy within the grid. We are investing in new technology such as the Advanced Distribution Management System to replace our existing system that is capable of facilitating renewable energy in the future.

For augmentation and connection capex, we are proposing a 47% increase in aggregate for these categories, albeit from a very low base of around 5% of total capex. Augmentation capex accounts for the majority of the increase. The principal driver underlying increased augmentation capex is a result of been an increase in major connections on the network. This is resulting in high rates of peak demand growth on ‘hotspots’ of our network such as

[2] Excluding capital contributions

Greenacre, Darling Harbour, Mascot and Macquarie Park. This is causing constraints in these areas of the network resulting in the need for growth capex.

For non-network capex we are proposing a 17% increase in capex. In the sections below, we discuss the drivers of our non-network ICT ($157 million) and OTI and innovation ($58 million), property ($208 million)and fleet ($94 million) and plant capex ($30 million).

We are proposing a similar level of capex in the current period, but the composition of our ICT capex is changing in line with four key strategic directions.

- Cyber security – We are increasing investment in cyber security. We have a planned program to expand the capabilities of our existing ICT infrastructure so it is more resilient to, and better able to counteract, cyber security threats. A cyber security attack of our network would cause severe damage to communities, businesses and potentially Australia's national security. In the current environment, it is therefore prudent to invest in cyber-security measures.
- Modernising our systems – We are investing in modernising our systems and processes At present, scheduling and resource allocation for our field force is principally managed through paper based 'job packs'. This leads to delays in the provision of information to and from field. The paper based system also requires workers to periodically return from the field to input data in our SAP asset management systems about the status of a job. Our field force automation project will modernise these processes by introducing a mobile ICT platform for our field workforce.
- Digital strategy – We will be implementing a digital strategy that provides customers with improved information and services.
- OTI and innovation projects – We are proposing to invest $58 million on non-network OTI and new innovation portfolio including trials on demand management trials and customer battery storage demand response and other projects.

Our corporate property capex will increase by 21% compared to the previous period. The increase in capex does not take into account the sale of our existing properties in the 2019-24 period, which are captured as a reduction to our regulatory asset base. The key driver of our corporate property investments are:

- Optimising our corporate property holdings so they are efficiently deliver our maintenance, network and corporate activities for the 2019-24 period, taking into account the recent changes in our internal workforce.
- Replacing or refurbishing a number of our depots which are over 50, and at risk of not meeting modern day workplace health and safety regulations due to their condition.

Our fleet capex will increase by about 75%. In the last period, we extended the life of our existing fleet to defer capex. However, in the 2019-24 period we will need to renew our fleet to keep asset age at a stable level.

Our capitalised overheads will decline by 15%. The reason relates to the transformations we have made to our total support activity in the business. This has reduced the capital overheads in our regulatory proposal.

Further detailed information on the composition and drivers of capex, together with the material programs are provided at Chapter 5 (replacement), Chapter 6 (augmentation and connection), Chapter 7 (non-network) and Chapter 8 (capitalised overheads) of Attachment 5.01 of our regulatory proposal.

4.2 Provide the model(s) and methodology *Ausgrid* used to develop its total *forecast capex*, including:

Table 12 below identifies documentation that we have provided the AER in respect of our models and methodologies used to develop our total capex forecast for standard control services. Further detailed information on our forecast capex methodology is set out in Attachment 5.01. We have described the capex model used to consolidate our total capex proposal (Business Planning and Consolidation) in Attachment 5.03, and have undertaken an external assurance of the model. The capex model cannot be provided in physical form to the AER as it is a SAP application.

Table 12. Provision of model and methodology relevant to total forecast capex

Attachment Number	Response	Content
5.01	Ausgrid's proposed capital expenditure	Chapter 1 provides a description of our total capex forecast method
5.02	Master list of capex projects and programs	Provides the expenditure outcomes from the Business Planning and Consolidation model used by Ausgrid to model total capex
5.03	Description of the Business Planning and Consolidation (BPC) model	Provides information on the capex model used by Ausgrid to consolidate total capex
5.06	Unit cost methodology	Provides information on our methodology to develop unit costs for system projects
5.07	2017 Electricity demand forecasts report	Provides information on our methodology to develop spatial demand forecasts
5.09	Cost benefit analysis for planning	Provides information on our methodology for cost benefit model used for major projects.

(a) A description of how *Ausgrid* prepared the *forecast capex*, including:

Ausgrid’s preparation of forecast capex for 2019-24 relied on our Business as Usual (BAU) processes. This is described in detail in Attachment 5.01 of our proposal. In summary:

- Our initial step was to examine the drivers of investment at a high level. We assessed the condition of network, peak demand growth by location and the need for non-network investment in ICT, property and fleet. We also considered how our investments should cater for the changing energy sector, including peer-to-peer trading, in the future.
- Based on our driver analysis, we identified replacement, augmentation, connection and non-network projects. We applied a business case assessment to identify the optimal project to address the need. For major projects on the sub-transmission network, we undertook granular analysis of each asset. For the distribution network, we identified programs based on high-level analysis such as the condition of the assets.
- A key element of our forecasting method is to target investments that provide the most benefit to customers in terms of reliability and safety. For our major projects we use a cost-benefit model that quantitatively assesses the reliability, safety and environmental impact to customers from delaying replacement or growth investments. We compare the risks to the costs of the capital program to determine the optimal timing of the project. We also use Net Present Value analysis to determine the least cost option. We apply similar approaches to determining the most efficient program for our smaller value network investments.
- We based our unit costs on our previous experience with completing similar works, including efficiencies from recent transformations. For major projects, we developed detailed ‘site-specific’ estimates. For programs containing a large volume of assets, we

developed a ‘typical’ cost based on scope and location. In some cases, we used a trending approach to guide our estimate of expected costs. We also applied real cost escalators to labour and contract services.

- Our unit cost methodology identified the regional differences in delivering similar projects across our network. Our experience is that the cost of undertaking capital projects in the CBD and inner metropolitan areas of Sydney can be significantly higher than other parts of our network. For example, some of our larger projects require night work and traffic disruption measures when they traverse major highways and roads in Sydney. By developing costs on this basis, we can provide the AER and stakeholders with more transparent information to understand any potential cost differences with our peers.
- To consolidate and prioritise the program, we undertook high-level checks of the capital program using AER assessment methods, such as trend and category analysis. We then ranked the relative risk of each project and prioritised the program to achieve a balance between reliability and safety outcomes, and customer affordability. Finally, we examined our labour and contracting resources to ensure we can deliver the program in each region.

(i) how its preparation differed or related to budgetary, planning and governance processes used in the normal operation of *Ausgrid’s* business;

We largely used our existing BAU processes to derive the 2019-24 forecast capex used in our normal operations. However, we undertook the following additional checks for the 2019-24 forecast that have impacted the development of the Regulatory Proposal:

- We undertook a high level check of our replacement programs, by comparing our capital plan forecasts to the AER’s repex model predictions.
- We undertook more detailed labour demand and supply modelling to ensure that each element of the proposed forecast capex could be delivered through internal and external resources.

(ii) the processes for ensuring amounts are free of error and other quality assurance steps; and

Ausgrid used an internal assurance process when developing our capital plans for the 2019-24 Regulatory Proposal. This involves supervisory review, and assurance from the responsible Executive that all calculations and modelling are free of error.

This has been complemented by an independent review by Price Waterhouse Cooper (PWC) on systems and processes used to calculate the forecast capex for 2019-24. PWC’s report is at Attachment RIN04 (Regulatory models review).

(iii) if and how *Ausgrid* considered the resulting amounts, when translated into price impacts, were in the long term interest of consumers.

Ausgrid considers that the capex meets the long term interest of customers, consistent with the National Electricity Objective by contributing to affordable, reliable and sustainable services. These are values that our customers and stakeholders have identified as important to their long term interest, when we have engaged them in workshops and research. In terms of how the proposed forecast capex achieves these values:

- Affordable – Our capex program when translated to price impacts results in an overall network price decline on average for customers in the 2019-24 period. Further, from a long term perspective, our proposal will result in zero real growth in the Regulatory Asset Base on a per customer basis, contributing to long term affordability after 2024.
- Reliable – Our forecast methods allow us to identify the most risky assets that give rise to adverse reliability and safety outcomes for customers. We also examine the least cost option to address these risks, including demand management options. Together, this means our forecast capex for 2019-24 is able to maintain reliability and safety of services at least cost. We are also delivering reliability outcomes for new customers by providing additional capacity in areas of the network that are constrained as a result of peak demand growth from new customers.
- Sustainable – In developing our forecast capex for 2019-24 we explicitly considered how the changing energy landscape should impact on our short term investments. We have invested in new technology such as the ADMS to ensure we can facilitate our transition to the needs of customers in the future. Further information on our innovation program is outlined in Chapter 2 and 3 of our regulatory proposal document, together with section 2 of Chapter 5 of our regulatory proposal document.

(b) any source material used (including models, documentation or any other items containing quantitative data); and

The documents identified in 4.2 above include information on source material and quantitative data. For example, our demand forecast methodology sets out key source material such as energy efficiency assumptions.

(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 documents identified in 4.2 above also include information on the calculations on how source material has been transformed to generate data in Workbook 1. For example, we show how source data on energy efficiency has been used to derive spatial demand forecast information in template 3.4 of Workbook 1.

4.3 Identify which items of *Ausgrid*'s *forecast capex* are:

(a) derived directly from competitive tender processes;

(b) based upon competitive tender processes for similar projects;

(c) based upon estimates obtained from contractors or manufacturers;

(d) based upon independent benchmarks;

(e) based upon actual historical costs for similar projects; and

(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.

Capex

Ausgrid uses a blend of internal and external service providers to deliver capital works. For the most part Ausgrid's forecast capex is prepared using projected historical costs adjusted for efficiency improvements.

Attachment 5.06 (Unit cost methodology) has describes the principles, methodology and procedures used by Ausgrid to develop unit rate estimates for capital projects and programs for the 2019-2024 regulatory period.

The majority of the capital investment that Ausgrid is proposing to carry out during the upcoming regulatory period can be separated into:

- Major projects - unique capital projects and structured programs of work
- Replacement programs - where the primary driver is the need to replace poor condition assets in the network, and duty of care programs, where the primary driver is a regulatory compliance, staff safety, or community safety requirement.

The methods for estimating costs for major projects and major programs by project development stage are set out below.

Table 13. Cost estimating methods

Project development stage	Component of capex					
	Major projects	Replacement, duty of care planned and conditional	Replacement duty of care and reactive	11kV capacity	LV capacity	Customer connection
Planning estimate	Bottom-up (building blocks)	Bottom-up and historical	Historical (at the pool level)	Top down and historical cost analysis	Top down and historical cost analysis	Top down and historical cost analysis
Preliminary estimate	Bottom-up (site considerations)	Bottom-up	Bottom-up	Top down and historical cost analysis	Top down and historical cost analysis	Top down and historical cost analysis
Detailed estimate	Market	Bottom-up and market	Bottom-up and market	Bottom-up and market	N/A – not estimated	Bottom-up and market

Our forecasts for the regulatory proposal are for the most part based on the planning estimates stage with the exception of major projects as shown in the table below.

Table 14. Proportion of capex programs at each project development stage at time of regulatory submission

Gate	Project development stage	Component of capex					
		Major projects	Replacement, duty of care planned and conditional	Replacement duty of care and reactive	11kV capacity	LV capacity	Customer connection
1	Planning estimate	72%	100%	100%	100%	100%	100%
2	Preliminary estimate	26%	0%	N/A	0%	0%	0%
3	Detailed estimate	2%	0%	N/A	0%	0%	0%

A description of each of the cost estimating methods is summarised in the table below.

Table 15. Description of cost estimating methods

Method	Description
Estimating systems	Three main estimating systems are used to support the development of the costing methods: 1. **ATAD estimator.** This is an external software package, developed for electrical contracting work has been tailored by Ausgrid to estimate the costs of network infrastructure projects. Both internal and external data sources serve as basic cost component inputs to the system. 2. **CCL Estimator.** Distribution cable installation projects (up to 22kV) within major projects are estimated through the Contract Cable Laying (CCL) Estimator package. This has a similar bottom-up approach to ATAD but is tailored for cable assets. The system is based on competitive contractor rates and incorporates Ausgrid's specifications for laying underground cable (i.e. trench profiles, backfill and reinstatement requirements). 3. **Ausgrid Financial Management System (SAP).** Ausgrid's financial management system captures actual data and historical records, historical vendor quotes, and period contract rates or supply agreements, and externally sourced costs from the construction/engineering industry for material costs and contracted services costs. These costs can be accessed to develop estimated costs for future projects.
Bottom up estimates	Bottom-up estimates are developed using ATAD and CCL Estimator. The bottom-up estimating approach is based on a defined scope of work. Where historical costs have been utilised as part of the bottom-up estimates, these have been escalated to constant 2016/17 dollars by CPI only. Escalators for each component of the forecast unit costs (i.e. internal labour, contracted services, materials) have been applied. The cost components within the scope of work are estimated individually by asset or resource and are based on data from internal and external sources. The building blocks for bottom-up estimates are typically: • Labour • Contracted Services • Materials and Equipment. These are aggregated to form unit costs that are used in the development of project cost estimates
Historical analysis	The use of historical estimating has been used where past costs are efficient (assessed via benchmarking) or can be adjusted to reflect current and expected efficient practices. The unit costs in this category tend to be for programs with high (recurring) volumes and stable cost trends over time at a program level. Historically analysis is typically used for programs where it is not practical to rely on an average bottom-up estimate due to the unknown variability between projects. An example is distribution underground cable laying where the degree of traffic control and ground condition is not known in advance. The models use an appropriate sample of projects to form efficient unit rates for the 2019-24 regulatory proposal.
Top-down estimates	Top down estimating has been used where either historical unit costs are not considered to represent the future unit costs or where there are no historical costs from which the unit rates can be established. The top down estimating process employs a benchmark rate sourced from either AER RIN data or other comparable data sources.
Market rates	Market rates are used in the later stages of the project development and approval cycle. Market rates are those rates quoted to Ausgrid by contractors for a defined scope of work.

Delivery support

To support the use of external service providers, Ausgrid has established panel contracts and various types of contractual arrangements.

Panels

To support large program of works where external support is required, Ausgrid has established panel contracts with a number of providers selected through a competitive tender process. Panel contracts have pre-negotiated terms and conditions, and pricing approach that allow for easier and quicker access to external resources, thereby reducing delivery timeframes. The following table summarises the key panel contract types of services that Ausgrid currently has in place.

Table 16. Ausgrid panel agreements

Panel type	Description
Contract cable laying	This panel consists of three companies which provide coverage across Sydney South, East and North; as well as Central Coast and Hunter regions. Cable laying activities are fully outsourced to the panel of contractors.
Inside substation and civil works	The works include security perimeter and internal upgrades, oil containment, switchgear and feeder replacement, building restoration, demolition and civil works.
Reinstatement services (in progress)	This arrangement covers permanent reinstatement services after replacing or installing underground cable. Ausgrid works with local councils and Roads and Maritime Services (RMS) preferred contractors to complete reinstatement works.

The panel contracts have provided Ausgrid with the ability to secure better pricing due to economies of scale and greater certainty of work to contractors.

Contracts

Ausgrid applies various types of contractual arrangements depending on various factors including the work type, work volumes over a period of time and available market providers. The contractual arrangements have flexibility built in to allow ramping up or down of external resources depending on the work plan.

On an ongoing basis, there are activities where Ausgrid has limited or no capability, are outsourced under standard period contracts. The capital programs include:

- Project services such as traffic management
- Environmental and community consultation
- Tower refurbishment.

There are no items of forecast capex reflective of any amounts for risk, uncertainty or other unspecified contingency factors.

Fleet plan Capex

Ausgrid's forecast capex are based upon the following NSW Government Contract pricing, actual historical costs for similar projects, tendered historic pricing, SG Fleet Ausgrid's fleet services provider (FSP) and finally contractors or manufacturers estimates where significant updates or designs revisions have occurred.

Ausgrid separates the expense elements of fleet capex into two categories:

- Fleet Replacement Plans
- Fleet Refurbishment Plans (major inspections required by Australian Standards on cranes at 10 years).

Each expense element of fleet capex is derived using a number of the different methods outlined in above, including combinations of methods.

For Fleet Replacement Plans the major elements are made up from vehicles and plant.

Ausgrid's estimates have been prepared using current NSW Government Supplier Contracts for available vehicle categories such as vans, trucks and other vehicles – these costs are derived from costs updated quarterly in NSW Procurement system and supplied by the manufacturers. Plant and fit out pricing is derived from historical costs from previous tenders and assistance from FSP

For major inspections required by Australian Standards, previous quoted pricing for like scopes of work are used for the basis of cost.

For contracted services, Ausgrid has previously adopted a competitive tendering process to pre-select panels of preferred contractors for these works. Historical costs from previous procurements have been used to formulate estimates.

In preparing its estimates for fleet capex, Ausgrid has made no allowance for risk, uncertainty or contingency (4.3(f)).

Non-System Property Capex

Ausgrid cost elements for non-system property capex comprises mostly of contracted services.

For contracted services, Ausgrid has adopted a competitive tendering process to select preferred contractors for these works. Additionally, Ausgrid's cost estimates for contracted services are prepared by external Quantity Surveyors using industry accepted guides.

In preparing its estimates for system planning capex, Ausgrid has made no allowance for risk or uncertainty.

For further information, please refer to Attachment 5.20 (Non-network Property Plan).

ICT Capex

Each cost element is based on unit cost rates and effort estimates. Analysis of how the unit cost rates and effort estimates were derived is discussed below.

The unit rates are based on a number of inputs, as documented the following table.

Table 17. Unit cost elements and relevant forecast capex category

Unit cost element	Basis of the unit cost	Relevant forecast capex category
Internal labour / Labour hire	2016/17 actual blended rates and compared to an external benchmarking study	e) based upon actual historical costs for similar projects d) based upon independent benchmarks
Hardware – Server	Blended vendor contract cost renegotiated in 2016/17	e) based upon actual historical costs for similar projects c) based upon estimates obtained from contractors or manufacturers
Hardware – storage	Blended vendor contract cost renegotiated in 2016/17	e) based upon actual historical costs for similar projects c) based upon estimates obtained from contractors or manufacturers
Hardware - Telecommunications	Vendor contract cost renegotiated in 2016/17 which were initially subject to competitive tenders	e) based upon actual historical costs for similar projects b) based upon competitive tender processes for similar projects
Software	Current contract cost (usually competitive tender) and consultation with vendors	e) based upon actual historical costs for similar projects c) based upon estimates obtained from contractors or manufacturers

Unit cost element	Basis of the unit cost	Relevant forecast capex category
Facilities management	Blended vendor contract cost renegotiated in 2016/17 and compared to an external benchmarking study	e) based upon actual historical costs for similar projects d) based upon independent benchmarks
Data centre – Floor charge	Blended vendor contract cost renegotiated in 2014/15 and compared to an external benchmarking study.	e) based upon actual historical costs for similar projects d) based upon independent benchmarks
Desktop and service desk services	Vendor contract cost and compared to an external benchmarking study	e) based upon actual historical costs for similar projects d) based upon independent benchmarks

The project effort and resource estimates are largely based on historical costs for similar projects (that is, category "e) based upon actual historical costs for similar projects"). On a business case level, the basis of the project estimates are explained in the following table.

Table 18. Basis of ICT program justification effort estimates

Business case	Basis of business case effort estimate	Relevant forecast capex category
1. Regulatory and compliance systems	Historical estimates on similar regulatory projects	e) based upon actual historical costs for similar projects
2. Cyber security	Historical estimates on similar ICT security projects	e) based upon actual historical costs for similar projects
3. Application maintenance	Historical estimates on similar application maintenance projects and vendor contracts	e) based upon actual historical costs for similar projects c) based upon estimates obtained from contractors or manufacturers
4. Infrastructure & telecommunications maintenance	Historical estimates on similar infrastructure projects	e) based upon actual historical costs for similar projects
5. Workplace technology	Historical estimates on similar workplace technology projects	e) based upon actual historical costs for similar projects
6. Data and digital enablement	Historical estimates on similar digital and data projects	e) based upon actual historical costs for similar projects

There are no forecast capex estimates specifically due to category f) reflective of any amounts for risk, uncertainty or other 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*.

See Attachment 5.12 (Resourcing and Delivery Strategy for 2019-24 period). Other supporting material is referenced in Chapter 5 of the proposal and Attachment 5.01 (Ausgrid's proposed capital expenditure).

Capex categories

4.5 Describe each *capex category* and expenditures comprising these categories identified in the *regulatory templates*, including:

(a) key drivers for expenditure;

The key drivers for expenditure are set out in the following table.

Table 19. Description of activities by capex category

Capex cost category	Activities and relevance to capital expenditure objectives
Replacement programs	Consists of activities involving the replacement of existing assets that pose unacceptable safety, reliability, security or environmental risks. These activities and their associated costs relate to achieving capex objectives 2, 3 and 4.
Growth related capital programs	These programs relate to connection and augmentation activities that are aimed at ensuring customers access to our network and meeting demand and maintaining security, reliability and quality of supply. These activities therefore relate to meeting capex objectives 1-3.
Non-network related programs	This expenditure category relates to costs associated with ICT, non-network OTI and innovation, non-network property, fleet and plant. It includes the underlying technology required to operate and manage our electricity network, and activities to support our network, meet corporate obligations or drive efficiency. Therefore, the activities in this expenditure category relate to meeting all of the capex objectives.
Capital support programs	Capital program support costs (capitalised overheads and network overheads) make up the overhead costs that support the efficient delivery of the capital program. These costs are made up of direct costs (network planning) and indirect costs (network divisional management and business support functions; fleet; corporate support functions; logistics, warehousing and procurement; and IT). (Note these are different costs to non-network ICT and fleet discussed above).

(b) an explanation of how expenditure is distinguished between:

(i) greenfield driven and reinforcement driven *augmentation capex*;

As part of our network planning, we implement the option that is least cost on a net present value. This may give rise to greenfield or reinforcement driven augmentation capex.

Greenfield augmentation is where we install new substations (for example, zone substations) or new feeders on the shared network to meet growth in peak demand or to meet reliability licence conditions. Reinforcement augmentation is where we increase the capacity of an existing shared asset, for example, by upgrading the capacity of an existing feeder, or adding a transformer to an existing zone substation.

(ii) *connections expenditure* and *augmentation capex*;

We have categorised connection capex as new installations on, or upgrades to, the shared network to provide a reliable supply to a customer. Our connection policy determines the extent to which connection capex is included as a standard control service or funded by the connecting customers (capital contributions). The customer pays a contribution for any dedicated asset, or upgrades to the shared network when

Augmentations refer to installations on our shared network in response to an increase in peak demand. They may be activated by customer connection activity, but are not related to works we undertake specifically at the time of a connection. Augmentations also include reliability programs to meet licence conditions. For example, we must meet individual feeder performance targets in Schedule 3 of our licence conditions.

(iii) *replacement capex* driven by condition and *asset* replacements driven by other drivers (e.g. the need for greenfield or reinforcement driven *augmentation capex*); and

The majority of our replacement is driven by an issue with the condition of a network asset. The condition of the asset may be due to ageing, an inherent issue with the manufacturing quality of the asset, operating conditions, or damage due to weather events. In some cases, the asset's condition may be not compromised, but we need to replace the asset for other reasons. For example, the asset may not contribute to meeting modern day safety and environmental standards even if its condition is sound. A further example is when we replace an asset on the basis that the technology is obsolete and no longer capable of integrating with the efficient design of the network.

(iv) any other *capex category* or *opex category* where *Ausgrid* considers that there is reasonable scope for ambiguity in categorisation.

We have not identified any other case where the definition of an opex or capex category has reasonable scope for ambiguity in its classification.

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:

(a) For individual asset categories in each asset group set out in the regulatory templates, provide in a separate document:

(i) a description of the *asset* category, including:

(A) **the *assets* included and any boundary issues (i.e. with other *asset* categories);**

(B) **an explanation of how these matters have been accounted for in determining quantities in the age profile;**

(C) **an explanation of the main drivers for replacement (e.g. condition); and**

(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.**

See Attachment RIN05 (Repex model description).

(ii) an estimate of the proportion of *assets* replaced for each year of the *current regulatory control period*, due to:

(A) **aging of existing *assets* (e.g. condition, obsolesce, etc.) that should be largely captured by this form of replacement modelling;**

(B) **replacements due to other factors (and a description of those factors);**

(C) **additional *assets* due to the *augmentation*, extension, development of the *network*; and**

(D) **additional *assets* due to other factors (and a description of those factors).**

See Attachment RIN05 (Repex model description).

(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:

(i) rules, codes, licence conditions, statutory requirements;

(ii) internal planning and *asset* management approaches;

(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;

(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);

(v) technology/solutions to address needs, covering:

(A) ***network*; and**

(B) **non-network.**

(vi) any other significant matters.

See Attachment RIN05 (Repex model description).

(vii) Identify and provide information or documentation to justify and support any responses to paragraph 5.1(b) (i)-(vi).

All relevant supporting documentation is identified in Attachment RIN05 (Repex model description).

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.

Attachment RIN05 (Repex model description) provides the relevant information broken down into these categories.

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).

Noted. The information provided in Attachment RIN11 (Workbook 1, template 2.4) has been prepared in accordance with this guidance.

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*:

(a) Separately for *sub-transmission lines*, *sub-transmission* and *zone substations*, *HV feeders* and *distribution substations*, *Ausgrid* must explain how it:

(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:

(A) **how this value relates to the maximum demand that would be used for normal planning purposes;**

Sub-Transmission Lines (Table 2.4.1)

This data was prepared based on load flow results for both 2013/14 and 2017/18. The actual substation loads are based on the SCADA system for 2012/13 and 2016/17 and they are corrected for weather, power factor and abnormal switching to obtain loads for 2013/14 and 2017/18, respectively. A network model is developed using these substation loads and load flow of each feeder is determined. The loads are prepared under the following assumptions:

- For the greater Sydney sub-transmission network and Hunter sub-transmission network, loading was applied at each zone substations peak values
- For the Sydney Inner Metropolitan dual function network, loading was diversified to the summer system peak
- Peak demand (system, STS or zone) was measured at a 50% probability of exceedance (POE)
- Steady state feeder utilisation was modelled under system normal conditions.

The output from the network model is used for network planning purposes.

HV Feeders (Table 2.4.2)

HV feeder loads are not typically weather corrected for planning purposes as they often peak at different times and on different days to the zone peak load. It is time prohibitive to weather correct each individual feeder and it is often difficult to determine what is actual weather impact, natural variation or abnormal switching

The information used for planning HV feeders is discussed in our response to 6.2(a)(i)(B) below.

Sub-transmission, Zone & Switching Stations (Table 2.4.3)

The 2013/14 maximum demand was based on the weather corrected actual demand for zone and sub-transmission substations connected to Ausgrid's network as calculated for the 2014 spatial demand forecast release.

The forecasts of maximum demand are prepared for winter and summer at 181 zone substations and 33 sub-transmission substations. The forecasts are produced annually at the end of the summer season and use the latest summer and winter actual electricity demand data.

Forecasts are produced for 50% Probability of Exceedance (50 POE), 90% Probability of Exceedance (90 POE) and 10% Probability of Exceedance (10 POE) levels. The central forecasts used as part of the assessment of options for an identified need are the 50 POE forecasts. The 10 POE forecasts and 90 POE forecasts are used as part of an assessment of 'reasonable' scenarios which are designed to test alternate sets of key assumptions and whether they affect identification of the preferred option.

The forecasts for each substation are constructed from two primary components:

- A near term forecast that is based on the statistically derived trend line of the weather corrected historical customer electricity demand for the substation
- A medium to long term forecast that is based on a system level econometric model. (The econometric model is adjusted for energy efficiency, rooftop photovoltaic systems, battery storage systems, electric vehicles, customer growth and air conditioner penetration).

This recognises the need for the forecast model to consider both the short term trend and long term macro econometric factors.

A more detailed discussion of this is contained within Attachment 5.07 (2017 Electricity Demand Forecasts Report).

For network planning purposes, the forecasts are used to identify future capacity constraints and identify appropriate network or non-network options depending on the size and nature of the constraint.

Distribution Substations (Table 2.4.4)

Distribution substations are not weather corrected for planning purposes. Planning is based on actual load readings provided through the LV Load Survey program. Actual load readings are compared against the rating of substations to determine whether the load can be redistributed or whether the substation needs to be uprated.

The 2017/18 maximum demand data was based on 2016/17 actual data. Where maximum demand data was not available, demand was estimated by aggregating metering data.

(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;**

Sub-Transmission Lines (Table 2.4.1)

Refer to our response to 6.2(a)(i)(A) above.

HV Feeders (Table 2.4.2)

HV feeder loads are measured at the HV panel of the zone substation. It is recorded by SCADA based on 30 minute average interval data recorded every 15 minutes. Abnormal switching is removed by engineering review every peak season.

Sub-transmission, Zone & Switching Stations (Table 2.4.3)

Refer to our response to 6.2(a)(i)(A) above.

Distribution Substations (Table 2.4.4)

Distribution substation loads are sourced from the following systems and recorded in SAP:

- Maximum Demand Indicator (MDI) load data is recorded from field readings and provides instantaneous and maximum demand data at the distribution substation since the previous reset date. MDI data is available for most substations except for Hunter pole top transformers and older Hunter kiosks. The measurement point is on B phase of the low side of the transformer tails.

- Distribution Monitoring & Control (DM&C) devices record interval load data at the distribution substation that is entered into SAP after every peak season. DM&C is installed at approximately 20% of distribution substations. The measurement point for each phase is the summation of the LV distributor loads.
- Load Information System estimates load data for most distribution substations after 2016. It uses an algorithm to estimate load based on Geographical Information System (GIS) connectivity and the summation of customer meters connected to the asset. Non-interval meter load data is replaced with interval meter data from a nearby customer with similar customer type and energy usage.

Load readings undergo an engineering review to determine if any of the readings are abnormal (typically due to switching). Any abnormal readings are removed before the data is entered into SAP.

(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**

Sub-Transmission Lines (Table 2.4.1) and Sub-transmission, Zone & Switching Stations (Table 2.4.3)

All forecasts and weather-correction parameters are estimates.

For some individual circuits, actual data is not available and estimates have been made using substation SCADA points, load-flow results and/or engineering judgment. This data may not be available because metering points have not been installed, there are metering errors, or the circuit was abnormally switched at the time of local area or system peak. The basis of the estimates include engineering judgement about abnormal switching and metering error, with validated load-flow studies used in network analysis to derive alternative estimates. Due to the absence of any verifiable actuals, this data is the best available estimate of individual line loadings for the snapshots required by Table 2.4.1.

Ausgrid does not have an established process to assign sub-transmission feeders against HV feeder categories. This is an estimated value based on the estimated categorisation of zone substations.

HV Feeders (Table 2.4.2)

Refer to our response to 6.2(a)(i)(B) above.

Distribution Substations (Table 2.4.4)

Refer to our response to 6.2(a)(i)(B) above.

(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.**

Sub-Transmission Lines (Table 2.4.1)

Demand data for sub-transmission lines/feeders is determined on the same basis as data for Sub-transmission, Switching and Zone substations with the exception of sub-transmission connected loads (see comments on Table 2.4.3 below).

HV Feeders (Table 2.4.2)

HV feeder loads are weather corrected to POE50 based on the originating substation weather correction factor from the Spatial Demand 2017 Planning Forecast POE50 M. These factors can be derived from the comparison of actual to weather corrected values in the RIN template 5.4 MD and Utilisation.

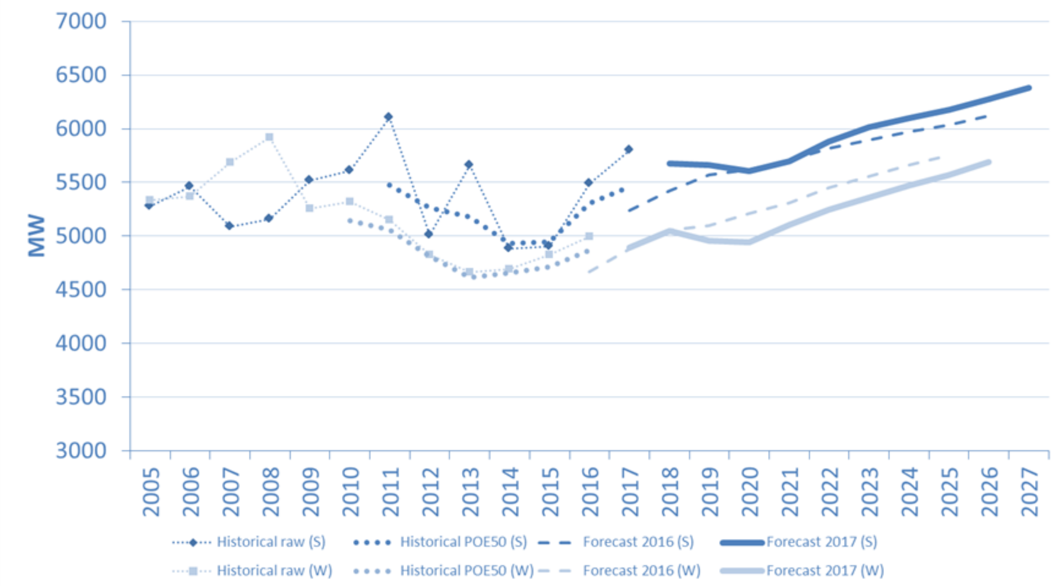
POE10 weather correction factors can be found in the Spatial Demand 2017 Planning Forecast POE10 H. These factors can be derived from the comparison of actual to weather corrected values in the RIN template 5.4 MD and Utilisation.

Sub-transmission, Zone & Switching Stations (Table 2.4.3)

At a system level, raw summer demand was 12.5% higher in 2016/17 than the calculated 50% POE value. The 10% POE value was 12% higher than the 50% POE value. Raw winter demand was 0.4% higher in 2016 than the 50% POE value, and the 10% POE value was 2% higher than the 50% POE value.

The below figure shows the historical raw and POE50 values for winter and summer and 10-year forecasts.

Figure 1. Ausgrid coincident system total summer and winter maximum demand forecasts



Distribution Substations (Table 2.4.4)

Distribution substation loads are not weather corrected. The load data is predominantly not interval data (Maximum Demand Indicator) and therefore it is unclear at what time the recording was made which means it is impossible to determine how much this value should be adjusted in any weather correction process. It is also unsuitable to use the zone weather correction factor and apply it to distribution substations that are not likely to uniformly share the weather correction factor of the zone.

(ii) Determined the rating data provided in the *asset* status tables 2.4.1 to 2.4.4, including where relevant:

(A) **the basis of the calculation of the ratings in that segment, including asset data measured and assumptions made; and**

(B) **the relationship of these ratings with *Ausgrid's* approach to operating and planning the network. For example, if alternative ratings are used to determine the augmentation timing, these should be defined and explained.**

Sub-Transmission Lines (Table 2.4.1)

Ratings are based on Ausgrid's standard rating rules and policies, and are recorded in Ausgrid's Ratings and Impedance Calculator (RIC) system (This applies to all feeders except LV feeders). Forecast ratings of future feeders are made using the RIC system for similar type of feeders and also standard ratings listed in the Planning and Data Management System (PDMS) considering standard trench profiles.

RIC is Ausgrid's primary reference for assets rating that provides the method for adapting standard nominal rating values to specific situations using generic asset types, for example, types of underground cable used in the Ausgrid network. This allows consistent application of thermal ratings across the Ausgrid network according to their purpose and location in the network. All applicable types of rating values, including other details such as assumptions and values used, are calculated and/or stored in the RIC system for each specific network rateable element of the particular asset categories such as feeders. The information stored in the RIC includes the following:

- Underground cables – lengths, construction, conductor size and material, screen size and material, insulation type, rated voltages, design/installed backfill thermal resistivity, laying, mounting, earthing and sheath bonding arrangements, contract/manufacture date
- Overhead lines – lengths, construction, conductor size and material, designed maximum conductor operating temperature.

The following types of ratings are typically calculated and stored within RIC for lines:

- Continuous or nominal rating for steady state operation
- Recurrent Daily Cyclic rating, where applicable, based upon standard Ausgrid load cycles
- Emergency ratings
- Seasonal variation of the above ratings.

RIC houses the ratings engine and other associated business rules. The GIS system feeds RIC with the required asset and network information for rating feeders. Similarly the SAP system provides asset information required to rate equipment and substations.

For rating and asset management purposes, a feeder is considered to be made of feeder sections, in turn, consisting of feeder portions and portion sections. The individual rating is assigned to each portion section and aggregated to a feeder level. Feeders can be made up of both overhead and underground Portion Sections installed in series.

The lowest rated element is the portion section, i.e. each portion section must be rated within a portion in order to establish a rating for the portion. Similarly each feeder portion must be rated to establish a rating for the rated feeder section or the feeder.

RIC as a rating system holds several business rules which enables the system to function and automatically produce ratings for all the assets considered to be rated.

The Ausgrid underground network comprises of various cable systems which are installed in different thermal environments. The Ausgrid underground cable rating methodology is mainly based on taking advantage of the thermal inertia available for buried cables and the cyclic nature of network loads applied. While rating underground cables, the impact of heating from neighbouring cables is accounted for through zone specific de-rating factors in order to allow for the increase in soil temperature above the chosen value due to mutual heating. The continuous ratings for underground cables are stored against its respective conductor code in RIC. The rating calculations for legacy or older cables have been performed externally and migrated into RIC. The continuous rating calculations for relatively newer cables have been produced using rating software or cable manufacturer catalogues based on current International Electrotechnical Commission (IEC) and Australian Standards AS) standards.

The overhead line rating methodology is based on a deterministic approach where bare and covered conductors are rated using a derivation of the "Heat Balance Equation". The continuous rating of an overhead conductor is calculated using a standard function of heat balance/thermal equilibrium at steady state. The continuous rating of an overhead conductor is mainly based on its ultimate steady state temperature or permissible operating temperature which in turn is limited by mandatory statutory clearances and cumulative loss of tensile strength of conductor due to annealing. Due to their nature, overhead conductors do not have cyclic ratings.

Some conductors are installed in a non-standard way. For example, cables can be installed in air, in tunnels, submerged and other special cases. These installations are considered individually, calculated external to RIC and the rating applied manually to the assets in RIC.

HV Feeders (Table 2.4.2)

HV feeder ratings are also calculated in RIC as per the Subtransmission lines above. Ratings provided are summer day ratings. For planning and operating purposes both summer and winter ratings are used and overhead lines also use day and night ratings.

Sub-transmission, Zone & Switching Stations (Table 2.4.3)

Total Ratings are based on summation of transformer nameplate or cyclic ratings and do not consider any other equipment limitations. Substation and N-1 ratings are based on Ausgrid's standard rating rules and policies.

This rating does not include 11kV or sub-transmission feeder limitations.

The standard report from Ratings & Impedance Calculator Report (R01) - Present Zone and STS Firm Ratings, is used as a main source of data. The report contains transformer throughput ratings data for each zone and STS transformer in the network and also nameplate rating data (only for the highest cooling mode). This data is merged with additional SAP nameplate data to obtain the lowest cooling mode nameplate rating for each transformer.

While nameplate ratings are provided by the equipment manufacturer, the normal and emergency cyclic ratings are calculated and apply Ausgrid's rating rules. These consider insulation loss of life and absolute temperature limitations for the top oil and the transformer winding.

The capacity calculation used for each substation varies due to the configuration and is a measure of the theoretical rating achieved by utilising all transformers in a substation. This measure ignores upstream and downstream feeder restrictions. Other restrictions include substations where all the transformers cannot be physically utilised at once due to fault level issues, frequency injection restrictions, etc.

The substation capacity based on transformer emergency cyclic ratings is also produced in the R01 report. This is the rating used when Ausgrid refers to the firm rating of the substation. This is the rating that, if exceeded, would mean there is load at risk at the substation and a project is needed to secure supply.

The objective of determining the thermal rating of equipment is to achieve a compromise between equipment utilisation, return on investment, deferred or reduced capital expenditure on the one hand, and equipment damage, accelerated ageing and customer supply reliability and quality on the other.

When equipment is grouped together at a particular location such as a substation, site specific information enables the appropriate individual equipment ratings to be extracted from the full range of possibilities, and subsequently incorporated into a ‘throughput rating’ application according to defined rules. As an example, in a zone substation this includes equipment such as a transformer, its connection cables, switchgear and operating mode.

The output capacity of oil-filled transformers is dependent on a range of factors:

- Operating temperature limitations of its components. These are specified in relevant Australian and international standards. There may be other limits specified in purchasing contracts or nominated by Ausgrid for specific assets.
- Absolute winding current limits. These are also specified in relevant standards or purchasing contracts.
- The cumulative effects of insulation ageing which are manifested as a decrease in mechanical and electrical strength of the winding insulation and/or oil due to operation at elevated temperatures. Life-insulation temperature characteristics are also provided in the relevant standards.
- Applicable ambient temperatures as seen by the transformer including their expected daily and seasonal variation.
- Measured oil and winding temperatures during ‘heat run’ testing. These are carried out as part of the contract type tests to confirm the nominal design capacity of transformers and may allow a degree of thermal ‘over-design’ to be exploited. In some cases the testing may be limited to the ‘highest’ and ‘lowest’ cooling modes or even to the ‘highest’ mode only.

- The anticipated demands on the transformer. These include assumptions about the daily load variation, the seasonal load variation, the number of occasions the transformer may be required to carry emergency loads, the ratio of emergency loads to normal daily loads, the pattern of load growth and relief etc. Some of these should be logically related depending on the number of transformers in the substation and its operating design. However simplified assumptions are necessary to make the calculations manageable.
- The thermal model adopted for the transformer. These are provided in relevant Australian and international standards and are dependent on the cooling mode utilised. Standard models have changed over the years as more test data on transformer temperatures has emerged and this can only be expected to continue.
- The assumed maximum ambient temperature at the time of critical loading on the transformer (used to check that permissible operating temperatures are not exceeded).
- Any limitations due to associated equipment in the 'throughput path' such as low voltage cables, current transformers, switchgear etc.
- Oil expansion limits. These are not part of the automatic calculation procedures but may be set based on operational experience.

Distribution Substations (Table 2.4.4)

Distribution substation ratings are based on the rating of the transformer, switches and fuses. These ratings are based on heat-run type tests that determine the actual ratings of the equipment which are generally higher than name-plate rating. These ratings are also used for planning and operating purposes.

(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 *Ausgrid*.

Sub-Transmission Lines (Table 2.4.1)/ Sub-transmission, Zone & Switching Stations (Table 2.4.3)

The growth rate is determined from annual base substation or feeder forecasts which include committed spots, transfers and projects. It is a derived value from the difference between 2018/19 forecast maximum demand and 2017/18 forecast maximum demand according to the relationship:

*Annual Maximum Demand Growth = (Maximum Demand (2018/19) / Maximum Demand (2017/18)-1)*100*

Note that Ausgrid prepares detailed forecasts for each substation which include both short term spatial and long term econometric factors, and does not use a single linear p.a. growth rate for planning purposes. This growth rate is therefore derived to achieve the expected maximum demand at each substation in accordance with Ausgrid's base spatial forecast for 2018/19.

Ausgrid produces separate winter and summer forecasts for each of our 181 zone substations and 33 sub-transmission substations. Attachment 5.07 (1027 Electricity Demand Forecasts Report) outlines Ausgrid's approach to forecasting maximum demand.

HV Feeders (Table 2.4.2)

HV feeder rate of growth is based on the originating substation underlying summer rate of growth (i.e. excluding impacts of spot loads and transfers) from the Spatial Demand 2017 Planning Forecast POE50 M, which is an output from our demand forecasting model.

Distribution Substations (Table 2.4.4)

Distribution substation rate of growth is based on the rate of growth of the CBD or non-CBD summer rate of growth from the Spatial Demand 2017 Planning Forecast POE50 M. It is not possible to split this up further as originating substations often supply multiple feeder categories (except CBD zones) and therefore apportioning the rate of growth between these feeder categories is impractical.

(b) In relation to the capex-capacity table 2.4.6, *Ausgrid* must explain:

(i) the types of cost and activities covered. Clearly indicate what non-field analysis and management costs (i.e. direct *overheads*) are included in the *capex* and what proportion of *capex* these cost types represent;

Costs covered are direct capex costs only and do not include network overheads (Network Planning) or Corporate overheads.

(ii) how it determined and allocated actual *capex* and capacity to each of the segment groups, covering:

(A) **the process used, including assumptions, to estimate and allocate expenditure where this has been required; and**

Ausgrid has mapped financial data generated from SAP BI based on drivers and internal asset class as the best possible methodology to complete template 2.4.6. This process involved estimation and allocation assumptions as Ausgrid does not currently report this information in the format required by the AER.

Assumptions relating to whether the expenditures are network or customer initiated include:

- Low Voltage Overhead and Underground Mains have been reported with Distribution Substations as instructed.
- Overhead and Underground services have been reported as un-modelled augmentation as these assets are generally customer connection assets and do not augment the network.
- Asset classes such as land, buildings and intangible easements are allocated between zone substations or sub-transmission substations and sub-transmission switching stations (STS/ STSS). High Voltage feeders' and distribution substations' location by CBD, urban, short/ long rural have been reported using allocation based on count of feeders by area plan.

(B) **the relationship of internal financial and/or project recording categories to the segment groups and process used.**

Ausgrid's financial data generated using SAP BI system are by lists of projects categorised further by Ausgrid's internal project sub-category and asset class. Using the asset class information, the projects were grouped and reported as per required in template 2.4.6. Ausgrid also relied on knowledge from subject matter expertise to provide information for customer-initiated and NSP-initiated capacity for actuals and forecast data.

(iii) how it determined and allocated estimated/*forecast capex* and capacity to each of the segment groups, covering:

(A) **the relationship of this process to the current *project* and *program* plans; and**

Customer initiated projects were assumed to have zero capacity added by Augex as customers will fund all capacity constraints.

Network initiated HV feeder capacity in 2017-18 to 2018-19 is based on known project rating changes.

Network initiated HV feeder capacity in 2019-20 to 2023-24 is based on the HV Reinforcement feeder budget forecast. This forecast determines the amount of capacity shortfall in the network and this is then adjusted by the capacity factor from 2.4.5 divided by 80% which is the target utilisation. The Urban and Short Rural feeder breakdown is based on the predominant feeder category in the zone that requires augmentation. CBD and Long Rural feeders are assumed to not require augmentation.

Network initiated distribution substation capacity is based on the information provided in 2.3.3. These estimates of how many of each asset will be required to be upgraded or added each year are then multiplied by an assumed rating change for each asset type. The total capacity change is then prorated across the Urban, Short Rural and Long Rural categories based on existing installed capacity of each feeder category. CBD substations are assumed to not require augmentation.

(B) **any other higher-level analysis and assumptions applied.**

HV Augex Modelling

The expenditure forecast for this program is derived from a bottom-up approach that estimates the expected capacity shortfall on each HV feeder and applies a unit rate to arrive at the cost of required augmentation. The applied unit rate is $250 per kVA ($'2017) of capacity shortfall. This is consistent with average benchmark cost for recent HV augmentation projects with narrowly defined scope of works. For a typical constraint of 1MVA this benchmark rate equates to 200-250 metres of underground feeder or 1 kilometre of overhead feeder.

The expected capacity shortfalls are identified by applying the load forecast of the final year in the regulatory period (i.e. 2023/24) to Ausgrid's existing HV distribution network. Identification of capacity shortfalls considers the:

- Thermal constraints of each feeder in system normal configuration and credible system abnormal configurations

- Feeder category (urban or non-urban)
- Forecast load of each zone substation at the end of the regulatory period (i.e. as at June 2024).

The system normal configuration is taken from Ausgrid's corporate GIS as at February 2017 and adjusted to reflect the expected summer and winter peaks of the final year in the regulatory period (i.e. 2023/24). The loading scenario for each zone substation is taken from Ausgrid's 2018 POE50M Spatial Demand Forecast (SDF). The SDF includes the zone substation's underlying rate of growth and the contribution of significant proposed network connections.

Each zone substation is assessed for capacity shortfalls in system normal and credible system abnormal configurations. A credible abnormal system configuration is considered to be the planned or unplanned loss of supply to a single HV feeder trunk section in a zone substation. The capacity shortfall is expressed as the quantity of load that cannot be supplied without exceeding thermal constraints or incurring voltage excursions after four restoration switching steps.

(c) Describe the projects and programs *Ausgrid* has allocated to the unmodelled augmentation categories in table 2.4.6, covering:

(i) the proportion of unmodelled *augmentation capex* due to this *project* or *program* type;

The proportion of un-modelled expenditure is approximately 10% of augmentation related expenditure.

(ii) the *primary drivers* of this *capex*, and whether in *Ausgrid*'s view, there is any secondary relationship to *maximum demand* and/or utilisation of the *Ausgrid network*; and

The only projects and programs that have been classified as un-modelled relate to reliability-driven projects. These projects are designed to address either:

- Sections of the network that do not meet Ausgrid's licence conditions relating to individual HV feeder or feeder section reliability, or
- High impact / low probability events relating to key infrastructure assets (e.g. major transport corridors, key network supply points).

(d) Separately for each network segment that Ausgrid 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 *Ausgrid* network to supply customer demand at similar service levels, or the improvement in service levels for a similar customer demand level:

(i) Describe the *network* segment, including:

(A) **the boundary with other connecting *network* segments; and**

Subtransmission and Zone Substations

Zone substations, subtransmission substations and subtransmission feeders have been broken into two segments per group on a geographical basis. The two areas are Sydney area networks and Hunter/Central Coast network areas.

HV feeders are segmented based on the Licence Conditions and STPIS definitions.

Distribution substations are segmented based on the feeder category of the originating feeder.

(B) **the main reasoning for the individual segment (e.g. as opposed to forming a more aggregate segment).**

Sub-transmission segments were designed to broadly reflect the different network designs and operating conditions. The primary differences are:

- The Sydney area network is predominantly shorter underground feeders compared to a long overhead network in the Hunter and Central Coast
- Sydney substations are generally larger capacity with more transformers, resulting in a higher utilisation threshold than Hunter and Central Coast substations
- Significant differences in average growth rates between the two areas.

HV feeders are segmented on the same feeder category criteria that we are required to report on feeder performance to IPART and for STPIS purposes. It is not practical to segment them differently.

Distribution substations are segmented in alignment with the HV feeders for simplicity.

(ii) Explain the utilisation threshold statistics provided (i.e. the mean and standard deviation), including:

(A) **the methodology, data sources and assumptions used to derive the parameters;**

(B) **the relationship to internal or external planning criteria that define when an augmentation is required;**

(C) **the relationship to actual historical utilisation at the time that augmentations occurred for that *asset* category;**

(D) ***Ausgrid's* views on the most appropriate probability distribution to simulate the augmentation needs of that network segment; and**

(E) **the process applied to verify that the parameters are a reasonable estimate of utilisation limit for the network segment.**

Zone and Sub-Transmission Substations

For zone and sub-transmission substation segments, the utilisation estimate is based on analysis of existing normal capacity from Ausgrid's rating system and load based on latest available metering data. Feeder data is based on analysis of feeder forecast results from the latest 2016/17 feeder forecast from Sub-transmission Planning.

For substations this is based on relationships between normal cyclic rating of assets and the forecast load to trigger growth related investment. For feeders this also includes the relationship between N loading and forecast loading under worst case credible contingencies, as determined by load-flow simulation. Where data is not available, 50% is substituted for the mean value of Utilisation Threshold.

The data used to determine utilisation threshold are substation normal capacity and firm capacity limit. Historical thresholds are indicative only, as past practice was to combine substation and feeder limitations into the substation firm capacity limit. Therefore some manual correction and estimation of data was required.

For zone and sub-transmission substations, Utilisation Threshold is derived from the relationship:

Utilisation Threshold = Firm Capacity / Normal Cyclic

Sub-transmission Feeders

Utilisation data for sub-transmission feeders is derived from the relationship between the N loading and N-1 loading (in MVA) – to determine the ratio between system normal and worst-case credible contingency loading.

Utilisation Threshold = N loading / N-1 loading

This data is sampled from the feeder forecast results prepared by Ausgrid's planning team.

It is Ausgrid's view that a statistical approach to modelling subtransmission level augmentation expenditure is not feasible due to the small population of assets and augmentation projects resulting in significant volatility. It is noted that these segment groups do not exhibit a normal distribution but other distributions are unlikely to provide a more suitable basis for modelling augmentation requirements.

HV Feeders

HV feeder utilisation threshold and standard deviations are based on 78 recent capacity projects. There are no CBD or Long Rural projects to assess.

- CBD was forecast to be a mean of 66.67% with a standard deviation of 0% based on the N-1 triplex requirement (that limits maximum load to the capacity that two of the three feeders in a bank can carry).
- Long Rural are assumed to be the same as Short Rural.

The projects are assessed to determine the lowest utilisation of the constrained feeders addressed by the project. It should be noted that the Ausgrid HV feeder network often has a "tapering" of the capacity further from the trunk section as smaller cross sectional conductors are used (often older out of service cables to reduce cost). This is reflected in the lower utilisation threshold than that expected by the planning criteria (over 80%).

Distribution substation utilisation threshold and standard deviation are based on 19 recent past capacity projects. There are no Long Rural projects to assess so they are assumed to be the same as Short Rural.

HV feeder investments are initiated based on NIS436 Distribution Network Planning Standard.

Distribution substations investments are initiated based on NIS436 Distribution Network Planning Standard.

HV feeder forecast utilisation thresholds are based on load-flow analysis. This analysis identifies whether it is possible to restore feeder failures within four switching operations. When this is unable to be achieved, the feeder is designated as non-compliant and its utilisation threshold is recorded.

Distribution substation forecast utilisation threshold are assumed to be the same as the historical utilisation thresholds.

HV feeders should be modelled as normally distributed as they are equally likely to be augmented above or below the utilisation threshold. The reason for investments below the threshold is that the utilisation threshold of a HV feeder is based on the 'trunk section' rating when this is often not the cause of the constraint or limiting section.

Distribution substations should be modelled as exponential as they will always trigger investments when they exceed 100% of the operational capacity. Investments may be made below 100% of the operational capacity for voltage constraints. However, these are less likely than load constraints and could be ignored to simplify the analysis.

HV feeders were compared to the historical thresholds and found to be in the same vicinity.

(iii) Regarding the *augmentation* unit cost and capacity factor provided, provide an explanation of each of:

(A) **the methodology, data sources and assumptions used to derive the parameters;**

(B) **the relationship of the parameters to actual historical augmentation projects, including the capacity added through those projects and the cost of those projects;**

(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**

(D) **the process applied to verify that the parameters are a reasonable estimate for the network segment.**

Zone and Subtransmission Substations/Feeders

Augmentation unit costs and capacity factors for subtransmission and zone substation projects have been derived from historical data of projects completed in the current regulatory submission.

As noted above, the derivation of project related planning parameters for asset categories with small populations of non-uniform assets and non-uniform solutions to growth drivers (particularly subtransmission lines, zone substations, and sub-transmission substations) is difficult. It is not possible to derive statistically meaningful parameters for Augmentation Unit Cost and Capacity Factor based on the both the historical and forward-looking project sets which comprise augmentation driven works for this segment of the network with any level of accuracy.

As noted in the AER augmentation model handbook, sample size is very important for statistical modelling, and the lack of samples (less than 30 per segment group) in the capacity augmentation area for subtransmission and zone segment groups mean that these variables can only be considered indicative, particularly for the forecast period.

The numbers provided in Table 2.4.5 are based on recent historical project costs (in real 2018/19 dollars) from the 2014-19 regulatory period (and the associated "capacity added").

For each sample, project parameters are derived from the following relationship:

Capacity Factor = [Capacity Added] / [Existing Capacity]

or alternatively expressed as:

([New Capacity] – [Existing Capacity]) / [Existing Capacity]

The average unit cost of augmentation for each network segment is derived as per the following formula:

$/MVA (forecast) = [Project Cost] / [Capacity Added]

An average value is then taken for each segment group.

Only sample projects with significant substation and feeder cost components were used to develop these estimates, to ensure no double-counting occurred.

It was found that capacity factor is very sensitive to the sample of projects used, particularly in those segments with very small sample populations. Many augmentation solutions at this level of the network are unique, driven by existing network design and constraints. No forecast capacity factor is possible due to the lack of upcoming projects driven by augmentation requirements in the forthcoming regulatory period.

Distribution (HV, Distribution substations & LV)

HV feeder utilisation augmentation cost and capacity factor are based on 78 recent past capacity projects. There are no CBD or Long Rural projects to assess. CBD was left blank as there are no projects to review and none forecast to be initiated. Long Rural is assumed to be the same as Short Rural. The projects are assessed to determine the capacity of all feeders that are constrained and then how much additional capacity was added. It is assumed that the capacity of all new feeders is 400A.

HV feeder and Distribution substation forecast capacity factors are assumed to be the same as the historical capacity factors. HV feeder projects have no possibility for double counting as the projects selected only addressed HV constraints. Similarly, HV feeder capacity factors were not changed from historical thresholds.

Distribution substation projects often add capacity to the LV distributor network (and vice versa). This is because while an overload may exist on one asset class the solution may be to augment the other asset class. The net result is that the overlap between augmentation of distribution substations and LV distributors is likely to be insignificant.

(e) Explain the factors *Ausgrid* considers may result in different *augmentation* requirements for itself as compared to other NEM-based DNSPs. *Ausgrid* must account for the degree that different *augmentation* requirements are driven by

differences in *asset* utilisation and maximum demand growth. *Ausgrid* 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:

(i) the maximum achievable utilisation of *assets* for *Ausgrid*; and

(ii) the likely *augmentation project* and/or cost.

For each significant factor discussed, *Ausgrid* must indicate relevant model segments and estimate the impact these factors will have on its *augmentation* levels and associated *capex* compared to other DNSPs.

It should be noted that the Ausgrid HV feeder network often has a "tapering" of the capacity further from the trunk section as smaller cross sectional conductors are used (often older out of service cables to reduce cost). This is reflected in the lower utilisation threshold than that expected by the planning criteria (over 80%). The HV Reinforcement budget is based on a bottom up model that accounts for this factor.

Ausgrid's connection policy impacts on augmentation requirements. The connection policy determines the contribution that connecting customers are required to make for augmenting the network.

7. CONNECTIONS EXPENDITURE

7.1 Provide and describe the methodology and assumptions used to prepare the forecasts of *connection* works including:

(a) Estimation of *connection* unit costs for each customer type; and

(b) Connection volumes for each customer type.

Given that customer connections activity is characterised by reasonably large volumes of low value projects, a top-down forecasting approach was adopted to forecast capital expenditure for customer connections. In summary, the key steps in the approach are:

- Analysing historical connection jobs to develop basic unit costs using past connection job volumes by work type, geographical area and recorded costs
- Developing forecast expenditure by using the forecast connection numbers by customer type and the relevant unit costs.

A small number of major connection projects are identified as part of the sub-transmission planning process. Ausgrid is generally approached by major customers at least three years prior to their desired connection date. These projects involve works required to facilitate sub-transmission connections (33kV or higher) and are modelled in the same way as Ausgrid's own major capital projects. A probabilistic approach is used to the forecasting of these projects which takes into account the stage at which the application has reached. Projects with certified design and/or signed connection offers are given a probability of 80% or higher of proceeding. Projects at an earlier stage are given probabilities of proceeding ranging from 5-20%.

Volume Forecast

The forecast of connection volumes is based on a projection of the volume of recent completed connections projects. The volume of connection projects include those undertaken as part of Ausgrid's Connection Program as well as individual, major sub-transmission projects. Projects are identified on the basis of their internal financial status as at the end of the financial year (i.e. either practically or financially completed). Detailed analysis of the Connection Program is used to quantify the volume of connection projects.

Projects have been categorised between residential and commercial connections and size of connection (i.e. above and below the threshold for connection contributions).

The base data for the volume forecast is the average number of projects created and completed over the last four years (2013/14 – 2016/17). Forecast volumes were then projected on the basis of an established relationship between construction and connection activity. Australian Construction Industry Forum (ACIF) forecasts of construction activity (November 2017) are used to project forecasts of connection projects.

Major sub-transmission projects are identified as part of the sub-transmission planning process as described above.

Expenditure Forecast

Average historical costs for projects completed in the past three years (FY15-FY17) were used to estimate unit project costs on the basis of cost data categorised by:

- Customer type (Residential, Commercial)
- Asset type
- Cost type (Labour, Contracted Services and Material).

For major projects, expenditure forecasts are prepared on the same basis as other major projects and adjusted for the probability of proceeding on the same basis as discussed above.

In addition to project based expenditure there is additional program based expenditure related to minor non-contestable works required to be undertaken to facilitate contestable connection projects. This work is removed from contestability on the basis of a network and safety risk assessment process which determines that the work is required to be undertaken internally by appropriately trained staff.

7.2 *Ausgrid* must provide its estimation of *customer contributions* based upon the estimated life and revenue to be recovered from *connection assets*, including:

(a) the expected life of the *connection*;

(b) the average consumption expected by the customer over the life of the *connection*; and

(c) any other factors that influence the expected recovery of the *Ausgrid* network use of system charge to customers.

Ausgrid operates within a contestable connections framework. All contributions are in the form of contributed or gifted assets. The value of these contributions is estimated on the basis of independent cost estimates that are updated annually for changes in cost and updated periodically.

The methodology used to forecast contestable Customer Contributions (in the form of contributed assets) is consistent with the approach used to forecast connections standard control service expenditure as follows. The model used to forecast the value of contributed assets can be provided if required.

Forecasts contributions of high-voltage and low-voltage assets are based on 2016/17 contributions and projected forward on the basis of independent forecasts of construction activity.

Forecasts of sub-transmission contributed assets are based on known or anticipated projects which are forecast using the same approach as for major replacement and augmentation projects.

See Attachment RIN11 (Workbook 1 – Regulatory Determination, Table 2.1.7) for the quantum of capital contributions.

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.

The Ausgrid policies, strategies and procedures relevant to the consideration of cost effective non-network options are provided as follows:

- Ausgrid Demand Management Standard NIS420
- Ausgrid Demand Side Engagement Document.

Copies of these documents have been provided in Attachment RIN06 (Ausgrid Demand Management Standard) and Attachment RIN07 (Ausgrid Demand Side Engagement Document.

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.

Based on the most recent demand forecast information, asset replacement requirements and infrastructure compliance issues, strategy options were developed to meet network needs. A preferred strategy option was selected based on the highest net present benefit that meets each network need.

For each preferred network option, demand management options were included alongside supply side options in developing the suite of potential solutions to meet the relevant network needs. The assessment determines the net present value of net benefits over a 20 year time horizon for the network and non-network solution options. Where non-network alternatives are found to form part of the least cost solution to the network need, the adjustments to capital and operating expenditures are included in the business plans. The potential for deferral of all capital projects above $1 million are considered in this process.

At the demand management consideration stage, there is generally little or no specific information known about actual demand management options available in the area of interest. Therefore, so assumptions are made about the likely scale of demand reductions possible and estimated costs. These assumptions are based on previous experience with delivery of demand management projects, submissions to non-network options reports from non-network solutions providers and lessons learned from demand management trials by Ausgrid and other networks in Australia.

For the 2019-24 regulatory period, the adjustments to capital and operating expenditure for the 2019-24 regulatory period are detailed in Chapter 5 (Forecast capital expenditure) and Chapter 6 (Forecast operating expenditure) of the Regulatory Proposal.

8.3 Identify each non-network alternative that *Ausgrid* has:

(a) commenced during the *current regulatory control period*; and

(b) selected to commence during, or will continue into, the *forthcoming regulatory control period*.

Ausgrid has implemented no demand management projects as an alternative to network investment in the current regulatory period. This inactivity has principally been due to the lack of demand driven network investments following the decline in customer demand for electricity from 2010 to 2014. Coupled with a deterministic approach to identifying network needs, which made demand management options unfeasibly expensive for asset retirement/replacement projects, there were no opportunities identified where non-network options were part of the least cost solution. In contrast, during the 2009-14 regulatory period, Ausgrid delivered 11 demand management projects; all related to demand driven network needs.

In contrast, there are a number of projects identified for the 2019-24 regulatory period where non-network solutions are potentially viable. This has principally been due to a change to a probabilistic planning approach for all network investments. Assessment of the expected unserved energy for all network needs has allowed demand management options to be considered for replacement projects along with demand driven network needs. Where non-network options can cost effectively reduce the expected unserved energy, demand management solutions can form part of the least cost solution to an asset replacement need.

For the forthcoming regulatory period, Ausgrid has proposed a $26.1 million ($real FY19) step change in operating expenditure for delivery of targeted demand management projects to defer network investment from three capital projects.

Details on the projects and the capital and operating expenditure impacts are found in Chapter 5 (Forecast capital expenditure) and Chapter 6 (Forecast operating expenditure) of the Regulatory Proposal.

Consistent with National Electricity Rules requirements, a regulatory investment test for distribution (RIT-D) will be conducted on all network investment projects over $5 million, and a non-network options report published as part of the demand management process. For more information on Ausgrid's demand management process, refer to Attachment RIN06 (Ausgrid Demand Management Standard) and Attachment RIN07 (Ausgrid Demand Side Engagement Document.

8.4 For each non-network alternative identified in the response to paragraph 8.3, provide a description, including cost and location.

Details on the projects and the capital and operating expenditure impacts are found in Chapter 5 (Forecast capital expenditure) and Chapter 6 (Forecast operating expenditure) of the Regulatory Proposal.

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 *Ausgrid* to an *Embedded Generator* in reflection any costs avoided by deferring *augmentation* of:

(a) *Ausgrid's* distribution network; or

(b) the relevant transmission network.

In the current regulatory period, Ausgrid made no payments to embedded generators as part of a demand management project. This inactivity has been due to the lack of demand driven network investments following the decline in customer demand for electricity from 2010 to

2014. In contrast, during the 2009-14 regulatory period, Ausgrid made more than $2.6 million in generator payments.

For the forthcoming regulatory period, Ausgrid has proposed a $26.1 million ($real FY19) step change in operating expenditure for delivery of targeted demand management projects to defer network investment. The share of the payment amounts for network support that would be made to embedded generators is not known at this time as it will be determined through a public consultation as part of the RIT-D process. As part of the National Electricity Rules requirements, a RIT-D will be conducted on network investment projects, and a non-network options report published as part of the demand management process.

For more information on Ausgrid's demand management process, refer to Attachment RIN07 (Ausgrid Demand Management documentation).

9. FORECAST INPUT PRICE CHANGES

9.1 Provide, in *Workbook 1 – Regulatory determination, regulatory template CPI series,* the CPI series and index used by *Ausgrid* in its *forecast capex* proposal and the forecast *opex* proposal.

Our CPI forecast is provided in Attachment RIN11 (Workbook 1 – Regulatory Determination, template 2.14).

9.2 Provide, in *Workbook 1 – Regulatory determination, regulatory template* 2.14, the *capex* and *opex* price changes assumed by *Ausgrid* in its *forecast capex* proposal and the forecast *opex* proposal. All price changes must be expressed in percentage year on year real terms.

Our forecast opex and capex escalators are provided in Attachment RIN11 (Workbook 1– Regulatory Determination, template 2.14).

9.3 Provide:

(a) the model(s) used to derive and apply the materials price changes, including model(s) developed by a third party;

Ausgrid has not developed a model for the application of material price changes, as we are not applying real materials price changes except where it applies to land. See Attachment 5.01 (Ausgrid's proposed capital expenditure) for a description of cost escalation applied.

(b) in relation to labour escalators, a copy of the current Enterprise Bargaining Agreement or equivalent agreement; and

A copy of the current enterprise agreement is provided at Attachment RIN08 (Ausgrid Agreement 2012).

(c) documents supporting or relied upon that explain the change in the price of goods and services purchased by *Ausgrid*, including evidence that any materials price forecasting method explains the price of materials previously purchased by *Ausgrid*.

Our cost escalation assumptions have been informed by a report prepared by BIS Oxford Economics, which is provided as Attachment RIN09 (BIS Oxford Economics – Cost Escalation Report).

9.4 Provide also an explanation of :

(a) the methodology underlying the calculation of each price change, including:

(i) sources;

(ii) data conversions;

(iii) the operation of any model(s) provided under paragraph 9.3(a); and

(iv) the use of any assumptions such as lags or productivity gains;

See Attachment RIN09 (BIS Oxford – Cost Escalation Report), which is the consultant report outlining forecast price changes and the methodology of the forecasts. See also Attachment 5.01 (Ausgrid's proposed capital expenditure), which outlines how the forecast price changes have been applied to capex. No productivity adjustments were made to forecast price changes. Expected efficiencies were applied to price and volume inputs rather than adjusted outputs.

(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 applied to both the capex and opex forecasts where applicable.

(c) if the response to paragraph 9.4(b) is negative, why it is appropriate for different expenditure escalators to apply.

Not applicable.

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.

The current enterprise agreement, Ausgrid Agreement 2012, provided in response to paragraph 9.3(b) will be replaced in 2018 with a new Enterprise Agreement. Ausgrid has recently completed negotiations on the new Enterprise Agreement, with the majority of employees voting to support it. This new agreement will replace the Ausgrid Agreement 2012 once it is approved by the Fair Work Commission.

It is expected that the 2018 agreement will be replaced in 2021, i.e. during the forthcoming regulatory control period. The negotiations for that have yet to commence and it is too early to comment on progress or outcomes.

10. OPERATING AND MAINTENANCE EXPENDITURE

Total forecast operating and *maintenance* expenditure (*opex*)

10.1 Provide:

(a) the model(s) and the methodology *Ausgrid* used to develop total forecast *opex*;

Ausgrid's opex model is provided at Attachment 6.02 (Opex model). Chapter 6 of the regulatory proposal and Attachment 6.01 (Ausgrid's proposed operating expenditure) explain the methodology used to develop total forecast opex.

Note, neither the opex model or opex RIN templates include transformation costs for 2017/18, as these are not recurrent costs and are excluded from our base year as outlined in Attachment 6.01 (Ausgrid's proposed operating expenditure).

(b) justification for *Ausgrid's* total *forecast opex*, including:

(i) why the proposed total forecast *opex* is required for *Ausgrid* to achieve each of the objectives in clause 6.5.6(a) of the *NER*;

(ii) how *Ausgrid's* total forecast *opex* reasonably reflects each of the criteria in clause 6.5.6(c) of the *NER*; and

(iii) how *Ausgrid's* total forecast *opex* accounts for the factors in clause 6.5.6(e) of the *NER*;

Attachment 6.01 (Ausgrid's proposed operating expenditure) contains the justification for Ausgrid's proposed total forecast opex.

10.2 Provide:

(a) the quantum of non-recurrent *opex* for each year of the *forthcoming regulatory control period*; and

(b) an explanation of the driver of each non-recurrent *opex*;

The only non-recurrent aspect of our opex forecast are our proposed step changes (see responses to question 11 for details on step changes).

10.3 If *Ausgrid* used a *revealed cost base year* approach to develop its total forecast *opex* proposal, provide:

(a) in Microsoft Excel format, reconciliation (including all calculations and formulae) of *Ausgrid's* forecast total *opex* proposal to forecast *standard control services opex* and dual function assets *opex* by *opex* driver in *Workbook 1 – Regulatory determination, regulatory template 2.16,* tables 2.16.1 and 2.16.3;

This is provided in Attachment RIN13 (Workbook 1 – Regulatory Determination, template 2.16, tables 2.16.1 and 2.16.3).

(b) the base year *Ausgrid* used; and

Ausgrid has used 2017/18 as the base year. This is set out in Chapter 6 of the regulatory proposal, Attachment 6.01 (Ausgrid's proposed operating expenditure) and Attachment 6.02 (Opex model).

(c) explanation and justification for why that base year represents efficient and recurrent costs;

Chapter 6 of the Regulatory Proposal and Attachment 6.01 (Ausgrid's proposed operating expenditure) explain and justify why 2017/18 represents efficient and recurrent costs.

10.4 If *Ausgrid* does not use a *revealed cost base year* approach to develop its total forecast provide:

(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;

(b) in Microsoft Excel format, reconciliation (including all calculations and formulae) of *Ausgrid*'s total forecast *opex* proposal to forecast *standard control services opex* and dual function assets *opex* by *opex category* in *Workbook 1 – Regulatory determination, regulatory template 2.16,* tables 2.16.2 and 2.16.4;

(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;

(d) explanation and justification for:

(i) whether *Ausgrid* considers there is a year of historic *opex* that represents efficient and recurrent costs; or

(ii) why *Ausgrid* considers no year of historic *opex* represents efficient and recurrent costs.

Not applicable as Ausgrid has used a revealed cost base year approach.

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.

This is provided in Attachment RIN11 (Workbook 1 – Regulatory Determination, template 2.16, tables 2.16.1 and 2.16.3).

10.6 Provide:

(a) the output growth drivers *Ausgrid* used to develop the amount of total forecast *opex* attributable to output growth changes;

(b) any economies of scale factors applied to the growth drivers;

(c) evidence that the growth drivers explain cost changes due to output growth; and

(d) if *Ausgrid* applied any composite multiple output growth drivers:

(i) the inputs for each composite multiple output growth driver; and

(ii) the weightings for each input;

See our response to question 10.7 below.

10.7 Provide an explanation of how, in developing the amount of total forecast *opex* attributable to output growth changes, *Ausgrid*:

(a) applied the output growth drivers; and

(b) accounted for economies of scale.

We used the AER's current two-step approach to estimate the impact of output growth. Firstly, we forecast expected growth in customer numbers, circuit length and ratcheted maximum demand over the 2019-24 regulatory period. Secondly, we estimated how much our opex changes for a one per cent increase in each of these output growth drivers. As preferred by the AER, we used the results of Economic Insights' Cobb-Douglas stochastic frontier analysis econometric model. The model produces estimates of how much opex changes for an increase in customer numbers, circuit length and ratcheted maximum demand based on data over the 2006-16 period.

Consistent with the AER's approach we have scaled the output growth factors so that they provide constant returns to scale. This means that a combined 1% increase in customer numbers, circuit length and ratcheted maximum demand will result in a 1% increase in opex.

Our application of output growth is shown in Attachment 6.01 (Ausgrid's proposed operating expenditure) and Attachment 6.02 (Opex model).

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.

This is provided in Attachment RIN11 (Workbook 1 – Regulatory Determination, template 2.16, tables 2.16.1 and 2.16.3).

10.9 Provide an explanation of:

(a) how, in developing the amount of total forecast *opex* attributable to changes in the price of labour and materials, *Ausgrid* applied the real price measures in *Workbook 1 – Regulatory determination, regulatory template 2.14*; and

An explanation is provided in Chapter 6 of our Regulatory Proposal. We also provide the calculations in Attachment 6.02 (Opex model).

(b) whether *Ausgrid's* labour price measure compensates for any form of labour productivity change.

The labour price measure that Ausgrid has used is a forecast of the Electricity, Gas, Water and Waste Services (EGWWS) Wage Price Index (WPI) for NSW, prepared by independent consultants BIS Oxford Economics.

We have not adopted a labour price measure which compensates for labour productivity change.

Our approach is consistent with the AER's preferred approach to adopt an overall electricity distribution specific productivity adjustment rather than adjusting the forecast EGWWS labour price change for EGWWS labour productivity.[3]

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.

This is provided in Attachment RIN11 (Workbook 1 – Regulatory Determination, template 2.16, tables 2.16.1 and 2.16.3).

[3] See AER, *Draft decision - Ausgrid distribution determination 2014–19 - Attachment 7: Operating expenditure*, November 2014, p 150.

10.11 Provide, in percentage year on year terms, the productivity measure that *Ausgrid* used to develop the amount of total forecast *opex* attributable to changes in productivity;

This is provided in Chapter 6 of our regulatory proposal and Attachment 6.02 (Opex model).

10.12 Provide an explanation of:

(a) how, in developing the amount of total forecast opex attributable to changes in productivity, *Ausgrid* applied the productivity measure in paragraph 10.11;

(b) whether *Ausgrid's* forecast productivity changes capture the historic trend of cost increases due to changes in *regulatory obligations or requirements* and industry best practice; and

(c) whether *Ausgrid's* productivity measure includes productivity change compensated for by the labour price measure used by *Ausgrid* to forecast the change in the price of labour.

As set out in Chapter 6 of the regulatory proposal, we considered Economic Insights' econometric model estimates of forecast productivity growth, consistent with the AER's Expenditure Forecast Assessment Guideline and past practice. This model currently estimates that productivity decreased over the period 2006 to 2016. Applying negative productivity growth would increase our opex forecast. We have decided not to do this. Instead we have applied productivity growth of zero, which is equivalent to not applying a productivity factor.

The productivity measure Ausgrid has considered (from Economic Insights' econometric model) is based on actual historic data, and year to year changes in costs, and therefore captures the historic trend of cost increases due to changes in regulatory obligations or requirements and industry best practice. It is derived using the same labour price measure that Ausgrid has used to forecast the change in the price of labour (i.e. the EGWWS WPI).

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.

This is provided in Attachment RIN11 (Workbook 1 – Regulatory Determination, template 2.16, tables 2.16.1 and 2.16.3).

11.2 Provide an explanation of why *Ausgrid* considers:

(a) the efficient costs of the *step change* are not provided by other components of *Ausgrid's* total forecast *opex* such as base *opex*, output growth changes, real price changes or productivity change;

(b) the total forecast *opex* will not allow *Ausgrid* to achieve the objectives in clause 6.5.6(a) of the *NER* unless the *step change* is included; and

(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.

See Attachment 6.01 (Ausgrid's proposed operating expenditure).

11.3 For all *step changes* in forecast expenditure provide:

(a) In *Workbook 1 – Regulatory determination, regulatory template* 2.17 the quantum of the *step changes* :

(i) forecasts for each year of the *forthcoming regulatory control period*; and

(ii) expected to be incurred, in the *current regulatory control period*;

(b) a description of the step change.

See Attachment RIN11 (Workbook 1 – Regulatory Determination, template 2.17) for the quantum of the opex step changes.

The demand management step change is an opex/capex trade-off where demand management (opex) is used to avoid or defer network investment (capex). The tariff reform acceptance research step change is for research to inform and expedite our transition to more cost reflective pricing as required by the AEMC's rule change for Distribution Network Pricing arrangements.

Ausgrid is not proposing any capex step changes.

11.4 For each *step change* listed in response to paragraph 11.3, provide an explanation of:

(a) when the change occurred, or is expected to occur;

(b) what the driver of the step change is;

(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

(d) whether the step change is recurrent in nature;

See Attachment 6.01 (Ausgrid's proposed operating expenditure) for details of the opex step changes.

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:

(a) the relevant *opex category*;

(b) the relevant *capex* category;

(c) total *opex*; and

(d) total *capex*;

See Attachment 6.01 (Ausgrid's proposed operating expenditure).

11.6 For each *step change* listed in response to paragraph 11.3, provide the process undertaken by *Ausgrid* to identify and quantify the *step change*; provide cost benefit analysis that demonstrates *Ausgrid* proposes to address the *step change* in a prudent and efficient manner, including:

(a) the timing of the *step change*; and

(b) if *Ausgrid* considered a 'do nothing' option, evidence of how *Ausgrid* assessed the risks of this option compared with other options;

See Attachment 6.01 (Ausgrid's proposed operating expenditure).

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:

(a) relevant variations or exemptions granted to *Ausgrid* during the *previous regulatory control period* or the *current regulatory control period*;

Not applicable. No relevant variations or exemptions were granted to Ausgrid during the previous regulatory control period or the current regulatory control period related to the change in regulatory obligation for Distribution Network Pricing arrangements.

(b) any relevant compliance audits Ausgrid conducted during the *previous regulatory control period* or the *current regulatory control period*;

Not applicable. No relevant compliance audits were conducted during the previous regulatory control period or current regulatory control period related to the change in regulatory obligation for Distribution Network Pricing arrangements.

11.8 For each *step change* listed in response to paragraph 11.7, provide, with reference to specific clauses of the relevant legislative instrument(s), the:

(a) previous *regulatory obligation or requirement*; and

(b) how the changed *regulatory obligation or requirement* is driving the step change.

See Attachment 6.01 (Ausgrid's proposed operating expenditure).

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.

This is provided at Attachment RIN11 (Workbook 1 – Regulatory determination, regulatory template 2.17, table 2.17.5) and is consistent with numbers reported in Attachment RIN11 (Workbook 1 – Regulatory determination, regulatory template 2.16, table 2.16.1).

ECONOMIC BENCHMARKING REPORTING

12. ECONOMIC BENCHMARKING

12.1 Complete the *Workbook 1 – Regulatory determination, regulatory templates* 3.1 to 3.7 in accordance with:

(a) the '*Economic Benchmarking RIN for distribution network service providers – Instructions and Definitions'* issued to *Ausgrid on* 28 November 2013, chapters 2 to 9*;*

(b) paragraphs 12.2 to 12.10.

Templates 3.1 to 3.7 in Attachment RIN11 (Workbook 1 – Regulatory Determination) have been completed in accordance with these requirements.

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:

(a) Total revenues must equal the total forecast revenues proposed by *Ausgrid* in its *regulatory proposal*, and

(b) Revenue groupings must reflect *Ausgrid's* forecast demand for its services in the *forthcoming regulatory control period* in its *regulatory proposal*.

Total revenues included in Tables 3.1.1 and 3.1.2 in Attachment RIN11 (Workbook 1 – Regulatory Determination) for standard control services equal total forecast revenues as proposed by Ausgrid in its Regulatory Proposal, noting that revenues in Ausgrid's Regulatory Proposal are presented in nominal dollars whereas Tables 3.1.1 and 3.1.2 require revenues in real dollars.

The forecast revenues in the groupings requested in Tables 3.1.1 and 3.1.2 reflect Ausgrid's forecast for the relevant services, noting that different forecasts are applicable to standard control services and alternative control services.

In addition, revenue from other sources in Table 3.1.1 comprises forecast revenue from Ausgrid's transmission standard control services. While revenue from other customers in Table 3.1.2 comprises revenue from Ausgrid's transmission standard control services only.

12.3 Information provided in *Workbook 1 – Regulatory determination, regulatory templates* 3.2, tables 3.2.1 and 3.2.2 must reflect *Ausgrid's cost allocation method*.

Template 3.2 in Attachment RIN11 (Workbook 1 – Regulatory Determination) has been completed in accordance with these requirements.

12.4 *RAB asset* financial data in the *Workbook 1 – Regulatory determination, regulatory template 3.3* must reconcile to that in *Ausgrid's regulatory proposal* PTRM and RFM.

The data in template 3.3 in Attachment RIN11 (Workbook 1 – Regulatory Determination) reconciles to the data used in the PTRM and RFM.

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)

Information in the RIN has met with definition of a tree, however we are unable to eliminate all trees under 3 metres measured from the ground as individual trees are not recorded in systems. The definition of a tree is:

> *"a tree is a perennial plant (of any species including shrubs that is: equal to or greater in height than 3 metres measured from the ground in the relevant reporting period; and of a species which could grow to a height such that it may impinge on the vegetation clearance space of power lines."*

Ausgrid does not record individual trees in its systems; however Ausgrid captured tree count data as part of vegetation management works on a sample of spans. Sampled spans covered 28% of Urban, 67% Long Rural, and 50% Short Rural feeders. This was used in DOEF0208 and DOEF0209 calculations.

12.6 In calculating responses to the *variables* DOEF0202 to DOEF0205, spans in the *network* service area where *Ausgrid* is not responsible for the *vegetation management* associated with the span are not to be counted.

The information provided in Template 3.7 in Attachment RIN11 (RIN Workbook 1 - Regulatory Determination) is consistent with these requirements.

12.7 "Total number of spans" (DOEF0205) does not include *service line* spans.

Service Mains spans, the connection from Ausgrid's network across public space to supply customers; for which Ausgrid is responsible to manage, has been included in DOEF0205. This ensures consistency with previous RIN reports and is described in Basis of Preparation (see Attachment RIN16).

12.8 *Ausgrid* 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).

The information provided in Template 3.7 in Attachment RIN11 (RIN Workbook 1 - Regulatory Determination) is consistent with these requirements.

Note Ausgrid has feeders which do not have a feeder classification such as transmission, auxiliary, HV customers and street lighting. These route line lengths are omitted from the classified values in the RIN template (i.e. "CBD, Urban, Short and long rural route line lengths"), but are included in the total route line length and explained in the BOP with the route line lengths for each table.

12.9 For the purposes of calculating the "*Route line length*" *variable* (DOEF0301) or other *variables* measured in terms of *route line length*:

(a) the length of *service lines* are not to be counted

(b) the length of a span that shares multiple voltage levels is only to be counted once

(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

The information provided in Template 3.7 in Attachment RIN11 (RIN Workbook 1 - Regulatory Determination) is consistent with these requirements.

12.10 All forecast *variables* in the *Workbook 1 – Regulatory determination, regulatory templates* 3.1 to 3.7 must align with those in *Ausgrid's regulatory proposal*. For the avoidance of doubt this includes forecast:

(a) *opex* and *capex*;

(b) maximum demand, energy delivery;

(c) revenues;

(d) quality of services variables including SAIDI and SAIFI; and

(e) quantities of physical *assets*

Templates 3.1 to 3.7 in Attachment RIN11 (RIN Workbook 1 - Regulatory Determination) have been completed in accordance with these requirements.

ALTERNATIVE CONTROL SERVICES REPORTING

13. ALTERNATIVE CONTROL SERVICES

13.1 The *overheads* relating to each *alternative control service* listed in paragraph 13.2 must be disclosed.

The overheads relating to each alternative control service, as a percentage of total costs, are set out in the table below.

Table 20. ACS Overheads

Service	Overheads (% of total costs)
Public lighting	26%
Type 5 and 6 metering	51%
Ancillary services	51%

13.2 Provide a list of all of the *alternative control services* that *Ausgrid* intends to provide to *customers* and levy charges for in the *forthcoming regulatory control period*.

We intend to provide public lighting, type 5 and 6 metering, and ancillary network services as alternative control services in the forthcoming period, consistent with the AER's final F&A paper. The individual ancillary network services we intend to provide are set out in Attachment 8.05 (Ausgrid's ancillary services).

13.3 Provide a definition of each *alternative control service* listed in paragraphs 14, 15 and 16.

Public lighting services

Public lighting comprises of the provision, construction and maintenance of public lighting and emerging public lighting technology, as set out in the AER's final F&A paper.

Type 5 and 6 metering

This service includes, as per the AER's final F&A paper, the maintenance, reading and data services involving type 5 and 6 meters (legacy meters).

Ancillary network services

Refer to attachment 8.06 ('Service description' tab) for definitions of each ancillary network service we intend to provide in the forthcoming regulatory control period.

13.4 For each *alternative control service* 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*.

Public lighting services

Attachment 8.12 (Public lighting price list) sets out the prices for the current regulatory control period for public lighting services and our proposed prices for the forthcoming regulatory control period.

Type 5 and 6 metering

Refer to ‘AER charges smoothed’ tab of Attachment 8.03 (Metering PTRM and pricing model). Rows 80 to 98 set out the charges which applied this period while rows 5 to 65 set out the prices we are proposing for the forthcoming period.

Ancillary network services

Appendix A of attachment 8.05 (Ausgrid’s ancillary services) sets out our proposed charges for the forthcoming regulatory period. The charges which have applied during each year of the current regulatory period are set out in the ‘2015-19’ tab of Attachment 8.06 (ANS Pricing models).

13.5 For each *alternative control service* listed in paragraphs 14, 15 and 16, specify the total revenue earned by *Ausgrid* in each year of the *current regulatory control period* and forecast to be earned in the *forthcoming regulatory control period*.

The following tables set out the ACS revenue for the current and forthcoming regulatory control period.

Table 21. ACS revenue 2014/15 – 2018/19 ($m, real FY19)

Service	2014/15	2015/16	2016/17	2017/18	2017/19
Public lighting	44.3	44.9	43.3	43.8	44.1
Type 5 and 6 metering	68.0	69.1	67.0	64.4	61.5
Ancillary services	18.4	38.7	45.1	41.9	41.9

Table 22. ACS revenue 2019/20 – 2023/24 ($m, real FY19)

Service	2019/20	2020/21	2021/22	2022/23	2023/24
Public lighting	44.7	43.5	42.6	42.0	41.6
Type 5 and 6 metering	58.5	55.6	54.7	53.3	51.8
Ancillary services	47.4	47.7	55.7	54.8	53.8

13.6 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:*

(a) specify the *labour classification level* used to provide the services e.g. outsourced or internally provided and labourer type.

(b) list all *direct costs*, and their quantum, in the make-up of the labour rate(s).

Public lighting

Public Lighting utilises both internal and external labour to provide Public Lighting services. Where internal labour is applied our pricing models utilise the ancillary network service labour rates tabled below. External rates are sourced by competitive tender and are applied to the pricing models as unit rates per task.

Refer to attachment 8.10 for the labour rates which have used to calculate public lighting charges. These are the same rates, adjusted for inflation and labour escalation, which we applied to set charge for the current regulatory control period.

Metering

Refer to our response to paragraph 15.2(b) below.

Ancillary network services

The labour rates which we used develop ancillary network charges are set out below.

Table 23. Current period ($, real FY14)

Proposed Category	Average Base Labour Rate	On-cost	Overhead Cost	Total Labour Rate
	$ per Hr	$ per Hr	$ per Hr	Labour Rate + On-Cost + Overhead + Indirect
Admin Support	$ 39.00	$ 20.37	$ 29.69	$ 89.06
Technical Specialist R2	$ 59.00	$ 30.82	$ 52.99	$ 142.81
EO 7/Engineer	$ 69.00	$ 36.04	$ 72.48	$ 177.52
Field Worker R4	$ 47.00	$ 24.55	$ 62.25	$ 133.80
Senior Engineer	$ 82.00	$ 42.83	$ 86.13	$ 210.96

Table 24. Forthcoming period($, real FY19)

Proposed Category	Average Base Labour Rate	On-cost	Overhead Cost	Total Labour Rate
	$ per Hr	$ per Hr	$ per Hr	Labour Rate + On-Cost + Overhead + Indirect
Admin Support	$ 43.72	$ 22.84	$ 33.28	$ 99.84
Technical Specialist R2	$ 66.14	$ 34.55	$ 59.41	$ 160.10
EO 7/Engineer	$ 77.36	$ 40.40	$ 81.25	$ 199.01
Field Worker R4	$ 52.69	$ 27.52	$ 69.79	$ 150.00
Senior Engineer	$ 91.93	$ 48.02	$ 96.56	$ 236.51
Engineering manager	$ 108.40	$ 56.62	$ 113.86	$ 278.88

Note that our proposed labour rates for the forthcoming period are the same as those which were approved in the current period. The only differences relate to updates for changes in inflation and real price growth in labour costs, and a new labour category ('engineering manager').

13.7 List each material category (e.g. *meters*, *poles*, brackets) required for the provision of each *alternative control service* listed in the response to paragraphs 14, 15 and 16.

(a) provide a description of each material category.

The descriptions are provided in the following table.

Table 25. Description of materials

Materials	Description
Public lighting	
Luminaires	Provides the housing for the lamp. The luminaire protects the lamp and reflects and diffuses the light. This directs the light to the desired area of coverage, whilst ensuring stray light does not; for example dazzle motorists. Modern luminaires usually contain a photoelectric (PE) cell that automatically switches the lamp on at night time.
Dedicated street lighting poles	This elevates the entire assembly above the ground. There are dedicated street lighting poles, but the majority of street lights are mounted on distribution poles.
Brackets	This supports the luminaire from a pole.
Lamps	This is the device which produces the illumination. It is mounted inside the luminaire. A range of technologies are used in lamps.
Photoelectric cells	Light sensitive device that switches the lamp on and off depending on the ambient light level
Metering	
N/A	N/A
Ancillary network services	
Tiger tails	Synthetic tubes that are clipped together over powerlines to provide visual indication to tradespeople and plant operators working in the area of live overhead power lines.

(b) provide the average unit costs for each material category.

The average unit costs are provided in the following table.

Table 26. Average unit costs

Materials	Description
Public lighting	
Luminaires	Refer to section 16 response
Dedicated street lighting poles	
Brackets	
Lamps	
Photoelectric cells	
Metering	
N/A	N/A
Ancillary network services	
Tiger tails (taraoli)	Refer to attachment 8.06 '08_Network Safety and Security', 'Tarapoli Hire' tab.

(c) list all *direct costs* included in the unit costs.

(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 above.

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 *Ausgrid's* annual *pricing proposals*.

Refer to the 'service description tab' of Attachment 8.06 (ANS Pricing Models) for a description of each fee and quote based service, the purpose of the service and a list of activities involved.

(a) specify if the charges are for *fee based* and/or quoted *alternative control services*;

Refer to the 'AER summary' tab of Attachment 8.06 (ANS Pricing Models).

(b) explain the reasons for the different charge with reference to the costs incurred;

Refer to the 'Fee Breakdown' tab of Attachment 8.06 (ANS Pricing Models).

(c) explain the method used to set the different charge; and

Refer to the 'Fee Breakdown' tab of Attachment 8.06 (ANS Pricing Models).

(d) provide the calculations underpinning the different charge.

Refer to the 'Fee Breakdown' tab of Attachment 8.06 (ANS Pricing Models).

14.2 Identify the tasks involved in providing the service in *Workbook 1 – Regulatory determination, regulatory templates* 4.3 and 4.4.

Refer to the 'service description tab' of Attachment 8.06 (ANS Pricing Models).

(a) map the class of labour required to provide the service listed in *regulatory templates* 4.3 and 4.4.

We have specified the class of labour required to provide each service in column "D" of the "Fee breakdown" tab of Attachment 8.06 (ANS Pricing Models).

(b) the number of workers required to undertake the task and deliver the service.

The number of workers required to deliver each service is specified in column "F" of the "Fee breakdown" tab of Attachment 8.06 (ANS Pricing Models).

(c) the average time required to complete the task and deliver the service.

The average time deliver each service is specified in column "G" of the "Fee breakdown" tab of Attachment 8.06 (ANS Pricing Models).

14.3 If materials are required to provide the service, specify each material category.

The fitting of tiger tails requires taraoli hire. The cost is set out in the 'Taraoli hire' tab Attachment 8.06 (ANS Pricing Models, 08_Network safety service and security).

14.4 Provide all current and proposed charges for each *fee based* and *quoted alternative control service* in the current and *forthcoming regulatory control periods*.

Appendix A of Attachment 8.06 (ANS Pricing Models) sets out our proposed charges for the forthcoming regulatory period. The charges which have applied during each year of the current regulatory period are set out in the '2015-19' tab of Attachment 8.05 (Ausgrid's ancillary services).

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:

(a) *direct materials* and *direct* labour costs;

Labour and associated incidental materials are detailed in Table 4.2.2 costs section.

(b) installation costs;

The Power of Choice metering reforms, which took effect on 1 December 2017, mean that Ausgrid is not responsible for installing new, upgraded or replacement meters.

In the current period (prior to 1 December 2017), new and upgraded meters were also not installed by Ausgrid. In NSW, customers were required to pay ASPs directly for installation costs.

(c) meter purchase costs;

Our meter purchase costs were $6,351,884 in 2014/15, $3,046,036 in 2015/16, $4,326,303 in 2016/17 and are estimated to be $1,763,687 in 2017/18. From 1 December 2017, we are no longer responsible for metering provision and will not incur any meter purchase costs.

(d) volumes of work;

The table below lists our work volumes for 2014/15 to 2016/17 are listed below.

Work volumes for 2017/18 to 2023/24 are detailed in 4.2.2 volumes section, rows 64-92.

Table 27. Volume of work

	2014/15	2015/16	2016/17
Meter purchase	54 579	27 547	64 605
Meter testing	2 243	2 448	459
Meter investigation	7 830	6 000	4 464
Scheduled meter reading	6 727 754	6 839 192	6 670 101
Special meter reading	0	33 395	56 788
New meter installation	51 884	-	-

	2014/15	2015/16	2016/17
Meter replacement	32 695	27 574	64 605
Meter maintenance	17 272	18 264	7 631

(e) other costs associated with providing metering services;

Not applicable.

(f) type of meters installed and forecast to be installed, separately for new meters and for replacement meters;

Ausgrid has type 5 and 6 meters installed only. We will not install any new or replacement meters in the forthcoming period, in accordance with the Power of Choice metering reforms.

(g) the volume of meters by type set out in (f) and the revenue earned and forecast to be earned by each meter type; and

Actual and estimated volume of type 5 and 6 meters and revenues from each meter type from FY15 to FY19 are set out in the table below.

Table 28. Volume of meters, current period

		2014/15	2015/16	2016/17	2017/18	2018/19
Type 5	Volume	660,576	660,164	606,215	570,135	523,626
	Revenue ($m, 2018-19)	25.2	25.6	24.8	23.3	21.4
Type 6	Volume	1,730,113	1,723, 390	1,711,141	1, 609,299	1,478,019
	Revenue ($m, 2018-19)	42.9	43.5	42.2	39.7	36.5

Forecast volume of type 5 and 6 meters and revenues from each meter type for FY20-FY24 are set out in the table below.

Table 29. Volume of meters, forthcoming period

		2019/20	2020/21	2021/22	2022/23	2023/24
Type 5	Volume	478 505	433 510	388 515	343 520	298 526
	Revenue ($m, 2018-19)	19.9	19.9	19.7	19.3	18.8
Type 6	Volume	1 350 658	1 223 653	1 096 647	969 642	842 637
	Revenue ($m, 2018-19)	34.0	33.9	33.6	32.9	32.1

(h) the total operating and *maintenance* costs incurred, and forecast to be incurred, for metering services.

Our total metering opex forecast is set out in attachment 8.01 (section 4) and attachment 8.03 (‘Forecast opex’ tab). The total operating and maintenance costs incurred in the current period is set out in Attachment 8.03, ‘Inputs opex’ tab at rows 48 and 49.

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:

(a) the type of work undertaken (e.g. *meter reconfiguration*, *special meter read*) including a description of the activities undertaken to provide the service;

Type 5 and 6 metering services includes meter maintenance, reading and data services.

Meter maintenance covers works to inspect, test, maintain and repair meters. Meter reading refers to quarterly or other regular reading of a meter. Metering data services are those that involve the collection, processing, storage and delivery of metering data and the management of relevant NMI Standing Data in accordance with the Rules.

(b) the labour costs involved in providing the service, including any *overheads*;

Maintenance

The labour costs involved with performing maintenance on a single meter is $92.85. This is based on 7,631 maintenance works performed on our meters in 2016/17 divided by expenditure of $708,588.

Meter reading

Our meter reading labour costs for the current and forthcoming regulatory periods are set out in the tables below.

Table 30. Meter reading labour costs, current period

		Travel	Read	Total
Per annum	Type 5	$1.15	$3.56	$4.70
	Type 6	$1.15	$1.19	$2.33
Per read	Type 5	$0.29	$0.89	$1.18
	Type 6	$0.29	$0.30	$0.58

Source: Sankofa Consulting, Diseconomies of meter density, October 2017, p. 23 (Attachment 8.04)

Table 31. Meter reading labour costs, forthcoming period

	2019/20	2020/21	2021/22	2022/23	2023/24
Cost per NMI (annual)	$4.63	$4.83	$5.07	$5.37	$5.75

Source: Sankofa Consulting, Diseconomies of meter density, October 2017, p. 23 (attachment 8.04)

Installation

In NSW, Accredited Service Providers (ASPs) are responsible for installing new and upgraded meters. We therefore do not a have a set of labour rates for new or upgraded meter installations for either the current or forthcoming regulatory control period.

Prior to 1 December 2017, we were still responsible for replacing type 5 and 6 meters. The labour costs involved in delivering this service is to be $118.23 per replacement. This is based on the total costs ($7,638,227) we incurred in replacing meters in 2016/17 and the volume of replacements (64,605) we made in that year. We will not be responsible for meter replacements next period.

(c) **any materials costs involved in providing the service;**

Refer to the response given to question 15.1(c) above.

(d) **the number (volume) of services provided and associated assumptions on which the volume of service was derived or estimated;**

Volumes for type 5 and 6 metering are detailed in Table 4.2.2 Volumes section – with columns depicting years. Also refer to our response to question 15.1(d) above.

We have assumed that the number type 5 and 6 metering services we provide will decline over the forecast period, in line with the commencement of the Power of Choice metering reforms. The assumptions which we have applied to derive the decline in our meter population, and by virtue of this the number of type 5 and 6 metering services we offer, are set out in section 6 of Attachment 8.01.

(e) **the charge per service; and**

Our charges for type 5 and 6 metering services are set out in attachment 8.03, '2019-24 prices' tab (rows 5-89 and rows 80-94).

(f) **the revenue earned by each service.**

We set out the revenue recovered by each service, according to meter type, in our response to question 13.5 above.

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*.

Attachment 8.03 sets out both our historical and forecast volume of customers (see 'Inputs' tab, rows 58 and 59).

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.*

Luminaire, support and bracket installation or replacements are considered capital expenses. Lamp, visor, PE cell and other miscellaneous materials replacements are considered operational expenses. This is the case for both current and forthcoming regulatory control periods.

16.2 Provide unit costs for the *current regulatory control period* and forecast for the *forthcoming regulatory control period* for:

(a) **luminaires;**

Luminiare unit rates are listed in Attachment 8.09 (Post June 2009 Annuity Prices FY20-24) in tab "Inputs - Inventory & Costs" in columns H and I.

(b) dedicated street lighting poles;

Dedicated street lighting pole unit rates are listed in Attachment 8.09 (Post June 2009 Annuity Prices FY20-24) in tab “Inputs - Inventory & Costs” in columns H and I.

(c) brackets;

Bracket unit rates are listed in Attachment 8.09 (Post June 2009 Annuity Prices FY20-24) in tab “Inputs - Inventory & Costs” in columns H and I.

(d) lamps;

Lamp unit rates are listed in Attachment 8.10 (Ausgrid - Public Lighting Maintenance Charge Model) in tab “Input - Inventory” in column W.

(e) photoelectric cells;

Photoelectric cell unit rate is contained in Attachment 8.09 (Post June 2009 Annuity Prices FY20-24) in tab “Inputs – General” in cell C26. This rate is used to recover the material capital component. Unit rates for maintenance purposes are contained in Attachment 8.10 (Ausgrid - Public Lighting Maintenance Charge Model), row 15.

(f) labour rate (per hour);

Labour rates are listed in Attachment 8.09 (Post June 2009 Annuity Prices FY20-24), tab “Inputs – General”, cell C13 and in Attachment 8.10 (Ausgrid - Public Lighting Maintenance Charge Model), tab “Input – General”, row 11. These are the same rates derived from ancillary network services.

(g) miscellaneous materials.

Miscellaneous material unit rates are listed in Attachment 8.10 (Ausgrid - Public Lighting Maintenance Charge Model) in row 16.

16.3 Provide the depreciation period in years for each type of luminaire.

Traditional Lamp based luminaires are depreciated over 20 years. LED luminaires are depreciated over 10 years. These values are used to calculate the luminaire annuity charges and are listed in Attachment 8.09 (Post June 2009 Annuity Prices FY20-24), tab “Inputs – General”, cells C5:C9.

16.4 Provide the bulk change cycle in years for lamps and photoelectric cells.

Bulk change cycle for all lamps is 4 years. Ausgrid has moved to a spot replacement only strategy for PE cells. These values are contained in Attachment 8.10 (Ausgrid - Public Lighting Maintenance Charge Model) tab “Input – General”, cell C26, C27 and C29.

16.5 Provide details of the *average* replacement age of each type of luminaire.

Ausgrid's SAP PM data for street lights does not allow for this data to be reported. When a new luminaire is installed, the date of installation is captured, however this over writes the date for the previous luminaire which in turn does not allow for the calculation of the age of the previous luminaire.

16.6 Provide the number of luminaires, by type, for the current and forthcoming regulatory control periods.

Number of luminaires by type is tabled in Attachment 8.10 (Ausgrid - Public Lighting Maintenance Charge Model) in tab “Input - Inventory”, columns O – U.

16.7 Provide the number of luminaires, *poles* and brackets replaced per year, for the current and *forthcoming regulatory control periods*.

See reset RIN table 2.2

16.8 Provide details, including assumptions used, for any other costs that are incurred for the provision of *public lighting services*.

All public lighting charges and assumption are contained within the pricing models. See Attachments 8.08, 8.09 and 8.10.

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.

See Attachments 8.08, 8.09 and 8.10.

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*.

See Attachment 8.09 (Ausgrid Pre 2009 'Fixed Charge' model FY20-24.xlsm, tab “Report – Charges”). There are currently 102 customers that consist of local councils and small customers. The number of local councils will reduce as mergers are made official. Currently we have 41 local council customers, which will reduce to 33 over the 2019-24 period. This does not impact the number of lights owned and maintained by Ausgrid.

NETWORK INFORMATION REPORTING

17. DEMAND AND CONNECTIONS FORECASTS

17.1 Provide and describe the methodology used to prepare the following forecasts for the *forthcoming regulatory control period*:

(a) *maximum demand*; and

(b) number of new *connections*.

See Attachment 5.07 (2017 Electricity Demand Forecasts Report) for the methodology used to prepare the maximum demand forecast.

The forecast volume of new (non-contestable) connections is based on projecting forward actual connections in 2016/17 on the basis of independent forecasts of construction activity.

The total volume of connections comprises the sum of standard control service connection projects (i.e. with a network funded component) and contestable connection projects (i.e. funded and constructed by customers).

17.2 Provide:

(a) the model(s) *Ausgrid* used to forecast new *connections* and *maximum demand*;

Ausgrid's model used to forecast maximum demand is substantially built in the SAS data management and analytics software platform. These models and processes are available to the AER for review at Ausgrid's head office as required.

The model used to forecast the volume of new connections is also available for the AER to review, if required.

(b) where *Ausgrid'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 *Ausgrid's* current approach. If any of this data is unavailable, explain why;

Regulatory templates 3.4 and 5.4 contain, and are based on, historically consistent weather corrected maximum demand data using Ausgrid's current approach as detailed in Attachment 5.07 (2017 Electricity Demand Forecasts Report). Please note that each time the forecast is produced (annually) historical weather corrected maximum demand is re-calculated due to the inclusion of new weather and demand data.

(c) for new *connections*, volume expenditure data requested in *Workbook 1 – Regulatory determination, regulatory template* 2.5; and

The forecast volume of new (non-contestable) connections is based on projecting forward actual connections in 2016/17 on the basis of independent forecasts of construction activity. The total volume of connections comprises the sum of standard control service connection projects (i.e. with a network funded component) and contestable connection projects (i.e. funded and constructed by customers).

This information has been provided in Attachment RIN11 (Workbook 1 – Regulatory Determination, template 2.5).

(d) any supporting information or calculations that illustrate how information extracted from *Ausgrid's* forecasting model(s) reconciles to, and explains any differences from, information provided in *Workbook 1 – Regulatory determination, regulatory templates* 2.5, 3.4 and 5.4.

The supporting information or calculations that illustrate how information extracted from the Ausgrid forecasting model reconciles with regulatory templates 2.5 and 5.4 is explained in Attachment RIN16 (Ausgrid's Basis of Preparation).

The supporting information or calculations that illustrate how information extracted from the Ausgrid forecasting model reconciles with regulatory template 3.4 is explained as outlined in its response to 3.4 of the 2016/17 Economic Benchmarking RIN Basis of Preparation.[4]

Supporting information is available on request to illustrate how information extracted from forecasting models reconciles to data provided in template 2.5.

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):

(a) the models used;

For maximum demand, the methodology used to prepare the maximum demand forecast is detailed in Ausgrid's Attachment 5.07 (2017 Electricity Demand Forecasts Report).

For customer connections, please refer to the response to question 7 above.

(b) a global[5] (top-down) and spatial[6] (bottom-up) demand forecast;

The top-down and bottom-up forecasting processes used in the maximum demand forecast are contained in the methodology document provided in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

Customer Connection forecasts are based on recent connection historical activity and are projected forward on the basis of independent forecasts of construction activity which is closely related to connections, as detail above.

(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);

For maximum demand, the inputs and assumptions used in the long term growth rate model, which affects the long term growth rates in the maximum demand forecast, are described in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

For customer numbers, please refer to the response to item 17.2(a).

(d) the weather correction methodology, how weather data has been used, and how *Ausgrid's* approach to weather correction has changed over time;

The weather correction methodology, and how the weather data is used, is described in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

Prior to 2009, weather correction was not carried out by Ausgrid. From 2009 to 2011, a weather correction process was developed that involved raising the load versus temperature trend line to coincide with the maximum observed daily load point. Since 2011, a 'Monte Carlo' or 'bootstrapping' simulation based weather correction methodology has been implemented.

[4] See 2016/17 Economic Benchmarking RIN – Basis of Preparation, available at: https://www.aer.gov.au/networks-pipelines/network-performance/ausgrid-network-information-rin-responses

[5] A global level forecast is the demand forecast that applies to the network service provider's entire network.

[6] A spatial forecast applies to elements of the network. For transmission network service providers (TNSPs), spatial forecasts could be at the level of connection points with distribution network service providers (DNSPs) and major customers. For DNSPs, spatial forecasts could be at the level of connection point, zone substations and/or HV feeders.

Prior to 2014, Ausgrid used apparent temperature for temperature correction. Following advice in 2013 from an independent audit to assess a range of temperature variables, analysis showed that the use of ambient temperature offered an improved weather correction performance. Since 2014, Ausgrid has used average daily ambient temperature.

(e) an outline of the treatment of block loads, transfers and switching within the forecasting process;

The treatment of block loads, transfers and switching is detailed in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(f) each appliance model[7] used, where used, or assumptions relating to average customer energy usage (by customer type);

Assumptions relating to customer energy usage in the residential customer segment, which forms part of an end-use model, are described in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(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 forecasting methodology uses historical observations (interval demand data) and includes calibration processes that remove the effect of abnormal loads such as switching and spikes and normalises the maximum demands against a weather set. This process is described in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(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;

The supporting information or calculations that illustrate how forecast data is consistent across forecasts provided for each network element in Regulatory template 5.4 is explained in Attachment RIN16 (Basis of Preparation) and in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(i) how the forecasts resulting from these methods and assumptions have been used in determining the following:

(i) *capex* forecasts; and

The demand forecast can be an input into the economic assessment for consideration of options for network needs. A cost benefit analysis is undertaken considering estimated cost of unserved energy, due to load above the firm rating and condition of the equipment, to identify the break-even investment date. The investment date is when the benefit of the reduced unserved energy exceeds the

[7] A NSP may incorporate an appliance model in its demand forecasting method to account for the effects of the uptake of appliances (such as air-conditioners) on maximum demand.

annualised cost of the investment. The capital expenditure forecasts in the Regulatory Proposal reflect the outcomes of the economic assessment.

(ii) operating and maintenance expenditure forecasts.

The demand forecast is an input into the economic assessment for consideration of non-network alternatives for network needs. Where non-network solutions form part of the least cost solution, the required operating expenditure will form part of a step change request in the revenue requirement. The operating expenditure forecasts in the Regulatory Proposal reflect the outcomes of the economic assessment.

Operating activities associated with connections are classified as alternate control services and are separately reported in Attachment RIN11 (Workbook 1 – Regulatory Determination, templates 4.3 and 4.4).

(j) whether *Ausgrid* used the forecasting model(s) it used in the joint planning process for the purposes of its regulatory proposal;

Ausgrid uses the maximum demand forecasts as detailed in Attachment 5.07 (2017 Electricity Demand Forecasts Report) as a key input into joint planning processes. The outcomes of joint planning are reflected in the forecasts included in our Regulatory Proposal.

(k) whether *Ausgrid's* 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);

Ausgrid forecasts the non-coincident maximum demand at the zone substation and sub-transmission substation level and calculates diversity (coincidence) factors to enable the coincident maximum demand at the network level to be derived. The maximum demand forecast at the feeder level is calculated using load flow techniques based on the maximum demand forecast at the sub-transmission substation and zone substation level.

Ausgrid considers "connection point" as meaning transmission connection point and has interpreted this, in respect to its network, as being comprised of all sub-transmission substations, zone substations connected at 132kV and high voltage customers connected at 132kV as outlined in its response to the Economic Benchmarking RIN.[8] This is not the same as the coincident maximum demand at the network level, which has specific inclusions such as 33kV embedded generators and non-132kV substations supplied from Endeavour Energy's network and exclusions of other major customer connected directly to the transmission network. Furthermore, Ausgrid does not forecast at the connection point level since there is no business purpose for this forecast. The forecasts at the zone substation, sub-transmission substation and feeder levels are produced since they are directly utilised by Ausgrid for network planning purposes.

Refer to the RIN16 (Basis of Preparation) and Attachment 5.07 (2017 Electricity Demand Forecasts Report) for further detail.

[8] See 2016/17 Economic Benchmarking RIN, available at: https://www.aer.gov.au/networks-pipelines/network-performance/ausgrid-network-information-rin-responses

(l) whether *Ausgrid* records historic maximum demand in MW, MVA or both;

Ausgrid records historic interval demand data in various units (amps, MW, MVA, MVAr, pf). Maximum demand is then calculated from the interval data after appropriate measures are taken to filter out abnormal loads such as switching and data spikes. Conversions between MW, MVA etc. are carried out using standard formulas.

(m) the *probability of exceedance* that *Ausgrid* uses in network planning;

Ausgrid uses 50% probability of exceedance in network planning of the subtransmission network and zone substations.

The planning of the HV and LV network does not use weather corrected loads as the load at lower levels does not necessarily follow the same weather correction patterns of upstream assets and the diversity of the lower network assets means they may not even peak on the same day. There are also too many assets to weather correct individually.

(n) the contingency planning process, in particular the process used to assess high system demand;

Ausgrid develops 'firm ratings' as an initial screening for substations which include an assessment of the worst case substation contingency (e.g. transformer failure) when determining network constraints under high system demand.

Load flow analysis is performed on HV feeders to ensure voltage and current are at acceptable levels during normal and abnormal switching. Investments are made proactively on forecasted loads based on historical recorded loads, the zone rate of growth, confirmed network changes and spot loads.

Distribution substations and LV distributors are planned to ensure that voltage and current are within limits under normal network operation. Investments are made reactively based on actual measured loads.

Ausgrid's approach is described in its planning standard, NIS 436 Distribution Network Planning Standard.

(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;

A Cost Benefit Analysis is undertaken considering estimated cost of unserved energy, due to load above its firm rating and condition of the equipment, to identify the break-even investment date. The investment date is when the benefit of the reduced unserved energy exceeds the annualised cost of the investment. Load sharing across network elements and non-network solutions are assessed as part of the cost benefit analysis. Ausgrid's approach to this is described in its planning standard, Planning Standard NIS 419– Area Planning.

As part of our investment governance process, a review is carried out for every capex project greater than $1 million to determine whether it would be cost-effective to defer the investment through the implementation of non-network solutions. This is assessed as part of the area planning process, and also for individual projects as appropriate. Where non-network projects identified in the investigation process are determined to be cost effective, they are implemented and the associated capex project is deferred.

(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 *Ausgrid's* network;

AEMO produces transmission connection point forecasts for principally two regions within Ausgrid's network area; one forecast for the greater Sydney and Central Coast region and one forecast for the Lower and Upper Hunter region. These regions represent 178 of Ausgrid's 181 zone substations and 33 sub-transmission stations, comprising 111 transmission connection points. Three of Ausgrid's zone substations are supplied from Endeavour Energy's network and are a small part of AEMO's Western Sydney region. Ausgrid produces unique forecasts for each of the 213 zone and sub-transmission stations.

AEMO are restricted to the two regions due to the mesh network linking transmission connection points in the Ausgrid network area. As the AEMO transmission connection point forecasts do not represent a network asset where an investment assessment would need to be undertaken, Ausgrid do not produce forecasts for the AEMO regions.

Refer to Attachment 5.07 (2017 Electricity Demand Forecasts Report) for further detail.

(q) how the normal and emergency ratings are used in determining capacity for individual *zone substations* and *sub-transmission lines*;

The substation ratings shown in Attachment RIN11 (Workbook 1 – Regulatory Determination, Template 5.4) 'Maximum Demand and Utilisation at spatial level' is the firm rating of the substation The firm rating is typically based on the emergency rating of the transformer throughput groups. The firm rating allows for a single contingency transformer outage.

Details on how this value is derived for the different zone substation configurations is set out in NIS426 - Ratings and Impedances of Network Assets.

The circuit capacities provided in Attachment RIN11 (Workbook 1 – Regulatory Determination, Template 3.5.1) are based on the summer ratings.

(r) where *Ausgrid* proposes to commence or continue a demand-related *capex project* or program during the *forthcoming regulatory control period* on a *HV feeder*:

(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:

(A) **assumed future load *transfers* between feeders;**

All HV feeder transfers are tracked within the Distribution Planning Investigation database and are used for HV feeder modelling purposes. The spatial demand forecast is adjusted for HV feeder transfers between zone transformers and zone substations. It does not account for transfers between HV feeders on the same zone transformer.

(B) **assumed feeder underlying load growth rates (exclusive of *transfers* and specific *customer* developments); and**

The HV feeder underlying load growth rates are based on the maximum demand forecast of the destination zone substation.

(C) **assumed *block loads*, and associated demand assumptions;**

Assumed block loads and associated demand assumptions are as outlined in the Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(ii) existing *embedded generation* capacity, and associated assumptions on the impact on demand levels;

Existing embedded generation and associated assumptions are outlined in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(iii) assumed future *embedded generation* capacity, and associated assumptions on the impact on demand levels;

Assumed future embedded generation and associated assumptions are as outlined in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(iv) existing non-network solutions, and the associated assumptions on the impact on demand levels;

Existing non-network solutions and associated assumptions are as outlined in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(v) assumed future non-network solutions, and associated assumptions on the impact on demand levels; and

Future non-network solutions and associated assumptions are as outlined in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(vi) the diversity between feeders;

The diversity between HV feeders are derived from a relationship between the maximum demand sum of all HV feeders in the same zone substation to the maximum demand of the zone substation itself in the same year and season.

(s) where *Ausgrid* 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*):

(i) assumed future load *transfers* between related *substations*;

The potential for 11kV load transfers as a demand-related capex project (or to defer a demand-related capex project) is assessed by planners at the area planning stage, and also reviewed annually after issue of the spatial demand forecast.

(ii) assumed underlying load growth rates (exclusive of *transfers* and specific *customer* developments);

Ausgrid uses the established zone substation forecasts provided in Attachment RIN11 (Workbook 1 – Regulatory Determination, Template 5.4) as the starting point, with further modifications to reflect expected changes to the network due to other major projects or customer connections that come through after the release of the planning forecast ("development forecast"). This forecast is used to determine the need for demand-related capex. This process is described in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

The planning forecast includes an underlying substation-specific growth rate, with some specific customer developments and demand assumptions added on top where there is sufficient probability that they will proceed. This forecast methodology is described in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(iii) assumed specific *customer* developments, and associated demand assumptions;

Specific customer developments are included in the demand forecast as block loads, and are based on the projected demand information provided to Ausgrid by the customer which is reviewed to include relevant diversity factors, and a probability factor is also applied to reflect the likelihood of the demand increase occurring at the specified time. Refer to details in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(iv) existing *embedded generation* capacity, and associated assumptions on the impact on demand levels;

The impact from existing embedded generation and associated assumptions are as outlined in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(v) assumed future *embedded generation* capacity, and associated assumptions on the impact on demand levels;

The impact from future embedded generation and associated assumptions are as outlined in Attachment 5.07 (2017 Electricity Demand Forecasts Report).

(vi) existing non-network solutions, and the associated assumptions on the impact on demand levels;

Where there is an existing non-network solution in place, the impacts on demand are included in the demand forecast and the network planning process.

(vii) assumed future non-network solutions, and associated assumptions on the impact on demand levels; and

Where there are future non-network solutions planned, the impacts on demand are included in the demand forecast and the network planning process.

(viii) diversity with related *substations*.

Peak load is used to determine substation constraints and the diversity of related substations does not impact augmentation timing. Where transfers are proposed, it is assumed the diversity of the load transferred is similar to the destination substation when undertaking load-flow analysis of feeder networks with diversity factors included.

17.4 Provide:

(a) evidence that any independent verifier engaged by *Ausgrid* 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

Ausgrid engaged GHD Advisory in August 2017 as an independent verifier with sufficiently capable expertise to examine the reasonableness of Ausgrid's maximum demand forecast methodology and customer connection forecasting methodology. Refer to Attachment 5.07 (GHD Review of 2017 demand and customer connection forecasts).

(b) all documentation, analysis and models evidencing the results of the independent verification.

The results of GHD's independent verification of Ausgrid's maximum demand forecast and customer connection forecast methodology are contained in Attachment 5.07 (GHD Review of 2017 demand and customer connection forecasts).

INCENTIVE SCHEMES AND OTHER REPORTING

18. EFFICIENCY BENEFIT SHARING SCHEME

18.1 For the purposes of applying the *efficiency benefit sharing scheme*:

(a) identify all cost categories proposed to be excluded from the operation of the *efficiency benefit sharing scheme*;

(b) explain for each cost category identified in the response to paragraph 18.1(a) the reasons for the proposed exclusion.

The current version of the EBSS already specifies a number of adjustments that the AER will make in applying the STPIS. Ausgrid agrees that these adjustments should be made.

In addition, we propose the following costs be excluded:

- Debt raising costs: Ausgrid intends to adopt the method that the AER uses to derive this cost. That is, debt raising cost will be calculated by applying a benchmark debt raising unit rate to the debt portion of our regulated asset base. Because this is not a revealed cost approach, these costs should not be subject to the EBSS.
- The demand management incentive allowance: the DMIA is defined a part of the demand management incentive scheme and under the current arrangements any underspend must be returned to customers in full.

See Attachment 9.01 (Application of incentive schemes) for further details.

19. SERVICE TARGET PERFORMANCE INCENTIVE SCHEME

19.1 Provide *Ausgrid's* detailed methodology for calculating the following parameters used in the *STPIS*;

(a) the *SAIDI, SAIFI* and *MAIFI* targets for each supply reliability area;

(b) the *customer* service parameters and targets;

(c) daily *SAIDI, SAIFI* and M*AIFI* and *customer* service performance derived from the individual *interruption* data under paragraph 19.3;

(d) the *MED* threshold derived from the daily *SAIDI* data;

(e) The incentive rates to apply to each supply reliability area.

Note: All calculations must be made in accordance with the *STPIS* and using data which complies with the *STPIS* definitions.

See Attachment 9.01 (Application of incentive schemes).

19.2 If *Ausgrid* proposes adjustments to the *STPIS* targets away from those based upon raw historical data *Ausgrid* must provide, in respect of each adjustment:

(a) the reasons for the adjustment;

(b) the quantum of the adjustment, and the effect of the adjustment on the targets for each of the supply reliability areas; and

(c) the method, basis and empirical data used as justification for the adjustment.

See Attachment 9.01 (Application of incentive schemes).

19.3 Provide the data required in *Workbook 1 – Regulatory determination, regulatory templates* 6.1 and 6.2.

See Attachment RIN11 (Workbook 1 – Regulatory Determination, templates 6.1 and 6.2).

20. PROPOSED CONTINGENT PROJECTS

20.1 For each contingent *project* proposed in the *regulatory proposal*, provide:

(a) a description of the *proposed contingent project*, including reasons why *Ausgrid* considers the *project* should be accepted as a *contingent project* for the *forthcoming regulatory control period*;

(b) the *proposed contingent capex* which *Ausgrid* considers is reasonably required for the purpose of undertaking the *proposed contingent project*;

(c) the methodology used for developing that forecast and the key assumptions that underlie it;

(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*;

(e) a demonstration that the proposed contingent *capex* for each *proposed contingent project*:

(i) is not included (either in part of in whole) in *Ausgrid's* proposed total *forecast capex* for the *forthcoming regulatory control period*;

(ii) **reasonably reflects the *capex* criteria, taking into account the *capex* factors, in the context of the *proposed contingent project*; and**

(iii) **exceeds either $30 million ($nominal) or 5 per cent of *Ausgrid's* proposed annual revenue requirement for the first year of the *forthcoming regulatory control period*, whichever is larger amount.**

(f) **the proposed trigger events relating to the *proposed contingent project*.**

Ausgrid has not identified any projects in the forecast capex in the 2019-24 period that meet the criteria of a contingent project as set out in the NER.

20.2 For each proposed *trigger event relating* to the *proposed contingent project* referred to in paragraph 20.1(f), demonstrate:

(a) **the proposed *trigger event* is reasonably specific and capable of objective verification;**

(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;**

(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 *network* as a whole;**

(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*;**

(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:**

(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**

(ii) **the costs associated with the event or condition are not sufficiently certain.**

As noted above, Ausgrid has not identified any projects in the forecast capex in the 2019-24 period that meet the criteria of a contingent project as set out in the NER.

20.3 Provide a summary of *Ausgrid'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*.

As noted above, Ausgrid has not identified any projects in the forecast capex in the 2019-24 period that meet the criteria of a contingent project as set out in the NER.

21. REVENUES FOR STANDARD CONTROL SERVICES

21.1 Provide *Ausgrid'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 *Ausgrid's regulatory proposal*.

Ausgrid has provided its calculation of the unsmoothed and smoothed revenues using the AER's post-tax revenue models submitted as part of the regulatory proposal. See Attachments 4.02 (PTRM for distribution) and 4.05 (PTRM for transmission).

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.

Ausgrid has not departed from the AER's post-tax revenue model.

22. INDICATIVE IMPACT ON ANNUAL ELECTRICITY BILLS

22.1 For the purposes of calculating the impact of *Ausgrid's regulatory proposal* on the annual electricity bill of typical residential and business *customer*s in New South Wales, provide the data/information required in *Workbook 1 – Regulatory determination, regulatory template* 7.6. Provide the data source for each input used for the calculation.

See Attachment RIN11 (Workbook 1 – Regulatory Determination, template 7.6).

Ausgrid's calculation of the indicative bill impacts for our typical residential and business customers in each year of the next regulatory control period is based on the following information:

- EnergyAustralia's regulated retail prices for residential customers in 2017/18. This information has been sourced from EnergyAustralia's website, see link below:

  https://secure.energyaustralia.com.au/EnergyPriceFactSheets/PricingFactSheets.aspx

- EnergyAustralia's regulated retail prices for business customers in 2017/18. This information has been sourced from EnergyAustralia's website, see link below:

  https://secure.energyaustralia.com.au/EnergyPriceFactSheets/PricingFactSheets.aspx

- Ausgrid's Distribution Use of System (NUOS) Tariffs for 2017/18. This information has been sourced from Ausgrid's website, see link below:

  https://www.ausgrid.com.au/-/media/Files/Industry/Regulation/Network-prices/AUSGRID-NETWORK-PRICE-LIST-FY201718.pdf

- The proposed Forecast smoothed revenue in each year of the next regulatory control period. This information has been sourced from the Ausgrid's PTRM and our Indicative Pricing Model.

23. PROPOSED TARIFF STRUCTURE STATEMENT

23.1 Provide the model(s) used to calculate the *long run marginal cost* estimates in *Ausgrid'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*.

See Attachment 10.03 (LRMC Model).

23.2 Provide and describe the methodology and assumptions used to prepare the *long run marginal cost* estimates in paragraph 23.1.

See Attachment 10.04 (LRMC methodology report).

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*.

Attachment 10.03 (LRMC Model), which has been provided in response to paragraph 23.1, is further broken down into two constituent models:

- Growth and Connections
- Replacement.

The models have differing drivers (peak demand and unserved energy respectively). Further detail on the approach can be found in Attachment 10.04 (LRMC methodology report). The data provided in table 7.7 of Attachment RIN11 (Workbook1 – Regulatory determination) reflects the Growth and Connections model. This model is similar to the approach followed by DNSPs to date for calculating LRMC. The Replacement LRMC model data can be found within Attachment 10.03 (LRMC Model) and should be interpreted in conjunction with the methodology in Attachment 10.04 (LRMC methodology report).

Capital expenditure (capex) forecasts utilise the same capital planning forecast that is utilised in the capex section of the regulatory proposal. All capex is Standard Control Services – Distribution in Real $2018/19. Capex utilised in the Growth and Connections Model is filtered by the following drivers in Ausgrid's capital planning tool (BPC, which is described in Attachment 5.03 (Description of the Business Planning and Consolidation (BPC) model):

- Customer Connections
- Growth.

Note that reliability driven expenditure has not been included.

Capex in the Replacement Model utilises large replacement project capex that is driven by probabilistic requirements (unserved energy).

No non-network expenditure is used in the marginal cost calculation as it is assumed to be fixed with respect to changes in network demand.

Operational expenditure (opex) required to service the incremental capex in the Growth and Connections model is defined as 2% of the Capex $. For example where $1,000,000 is proposed in capex for a particular year, the ongoing operational expenditure would be $20,000 per annum. No opex has been included in the replacement model (see Attachment 10.04 (LRMC methodology report) for further details).

Demand and energy forecasts utilise the same spatial demand forecast that underpins the capital planning forecast.

REGULATORY ASSET BASE AND TAX REPORTING

24. REGULATORY ASSET BASE

24.1 Provide *Ausgrid'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.*

Ausgrid's roll forward models (RFMs) for both distribution and transmission are provided at Attachment 4.01 (RFM for Distribution) and 4.04 (RFM for Transmission).

24.2 Provide details of each departure from the underlying methods in the *AER's roll forward model* for the calculation referred to in paragraph 24.1 and the reasons for that departure.

As approved by the AER for the 2014-19 determination, Ausgrid has used the distribution RFM for its transmission assets.

24.3 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.

There are no changes to asset service classification.

24.4 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.

The allocation of actual disposals between asset classes in the RFMs for distribution and transmission for 2014/15 are different to those provided in the 2014/15 Annual Reporting RIN. There was an error in the numbers reported and these have been corrected in the RFMs. The table below details the differences.

Table 32. 2014/15 Disposals

Distribution	Ausgrid	AER
Substations	980,813.4	980,813.4
Transformers	1,327,064.0	1,327,064.0
Land and easements	40,588,984.4	
Motor vehicles	3,277,787.4	
Buildings	59,607.7	3,277,787.4
System IT (dx)		40,588,984.4
Land (non-system)		59,607.7
Transmission	**Ausgrid**	**AER**
Transmission and zone land easements	1,411,861.6	
Zone buildings 132/66 kV	185,199.8	
Motor vehicles	544,705.2	
Buildings	9,905.7	544,705.2
Transmission building 132/66 kV		1,411,861.6
Transmission transformers 132/66 kV		185,199.8
Land (non-system)		9,905.7

25. DEPRECIATION SCHEDULES

25.1 Provide *Ausgrid's* calculation of the depreciation amounts for the relevant distribution *system* in respect of *standard control services* for each *regulatory year* of:

(a) the *current regulatory control period* using the *AER's roll forward model*, which is to be submitted as part of the *regulatory proposal*

Ausgrid's calculation of depreciation amounts for the current regulatory control period is provided in the RFMs. See Attachments 4.01 (RFM for distribution) and 4.04 (RFM for transmission). The RFMs roll forward the asset base using forecast depreciation as required by the AER in the 2014-19 regulatory decision.

(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*.

Ausgrid's calculation of depreciation amounts for the forthcoming regulatory period is contained in Attachments 4.02 (PTRM for distribution) and 4.05 (PTRM for transmission).

25.2 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 25.1 and the reasons for that departure.

For the purposes of 25.1, Ausgrid has not departed from the underlying methods of calculating depreciation in the AER's roll forward model and post-tax revenue model.

25.3 Identify any changes to standard *asset* lives for existing *asset* classes from the previous *determination*. Explain the reason(s) for each change and provide supporting information.

There have been no changes to standard asset lives for existing asset classes from the previous determination.

25.4 Identify any changes to new *asset* classes from the previous *determination*. Explain the reason(s) for using these new *asset* classes and provide supporting information on their proposed standard *asset* lives.

Ausgrid has not proposed any new asset classes.

25.5 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 supporting information. This should include a demonstration of the materiality of the change on the forecast depreciation allowance.

Ausgrid has not proposed to remove any existing asset classes from the previous determination.

25.6 Describe the method used to depreciate existing *asset* classes as at 1 July 2019 (the start of the *forthcoming regulatory control period*) and provide supporting calculations, if the approach differs from that in the *roll forward model*.

Ausgrid has not departed from the method of depreciating existing asset classes set out in the AER's most recent roll forward model for depreciation.

26. CORPORATE TAX ALLOWANCE

26.1 Provide *Ausgrid'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*.

Corporate income tax has been provided in Chapter 4 of the regulatory proposal and was calculated in the post-tax revenue models using a 30% corporate tax rate and assumed value of imputation credits of 0.40. See Attachment 4.02 (PTRM for distribution) and Attachment 4.05 (PTRM for transmission).

26.2 Provide details of each departure from the *AER's post-tax revenue model* for the calculations referred to in paragraph 26.1 and the reasons for that departure.

Ausgrid has not departed from the PTRM's corporate tax allowance calculations.

26.3 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 Federal tax laws governing depreciation for tax purposes.

Ausgrid has not proposed any changes to the tax standard lives for existing asset classes.

26.4 Describe the method used to depreciate existing *asset* classes as at 1 July 2019 (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*.

Ausgrid has not departed from the approach in the roll forward model.

26.5 Provide *Ausgrid'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*.

Ausgrid's approach to estimating the tax asset base for each regulatory year is outlined in Chapter 4 of the Regulatory Proposal. The calculations are contained in Attachments 4.01 (RFM for distribution) and 4.04 (RFM for transmission).

26.6 Provide details of each departure from the underlying methods in the *AER's roll forward model* for the calculation referred to in paragraph 26.5 and the reasons for that departure.

Ausgrid has not departed from the AER's roll forward model methodology.

26.7 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.

There are no differences in Ausgrid's capitalisation of expenditure for regulatory accounting purposes and tax accounting purposes.

MISCELLANEOUS REPORTING

27. RELATED PARTY TRANSACTIONS

27.1 Identify and describe all entities which:

(a) are a *related party* to *Ausgrid* and contribute to the provision of *distribution services*; or

(b) have the capacity to determine the outcome of decisions about *Ausgrid's* financial and operating policies.

Note: In the answers to this question:

A reference to "Ausgrid" or AOP is a reference to the Ausgrid Operator Partnership a partnership carried on by:

(a) Blue Op Partner Pty Ltd (ACN 615 217 500) as trustee for the Blue Op Partner Trust;

(b) ERIC Alpha Operator Corporation 1 Pty Ltd (ACN 612 975 096) as trustee for ERIC Alpha Operator Trust 1;

(c) ERIC Alpha Operator Corporation 2 Pty Ltd (ACN 612 975 121) as trustee for ERIC Alpha Operator Trust 2;

(d) ERIC Alpha Operator Corporation 3 Pty Ltd (ACN 612 975 185) as trustee for ERIC Alpha Operator Trust 3; and

(e) ERIC Alpha Operator Corporation 4 Pty Ltd (ACN 612 975 210) as trustee for ERIC Alpha Operator Trust 4;

A reference to AAP is a reference to the Ausgrid Asset Partnership[9], a partnership carried on by:

(a) Blue Asset Partner Pty Ltd (ACN 615 217 493) as trustee for the Blue Asset Partner Trust;

(b) ERIC Alpha Asset Corporation 1 Pty Ltd (ACN 612 974 044) as trustee for ERIC Alpha Asset Trust 1;

(c) ERIC Alpha Asset Corporation 2 Pty Ltd (ACN 612 975 023) as trustee for ERIC Alpha Asset Trust 2;

(d) ERIC Alpha Asset Corporation 3 Pty Ltd (ACN 612 975 032) as trustee for ERIC Alpha Asset Trust 3; and

(e) ERIC Alpha Asset Corporation 4 Pty Ltd (ACN 612 975 078) as trustee for ERIC Alpha Asset Trust 4.

In relation to 27.1(a), the following entities are a related party and contribute to the provision of distribution services:

(i) Ausgrid Management Pty Ltd (Ausgrid Management) ACN 615 449 548.

[99] AAP is not a related party to the Ausgrid Operator Partnership because it does not satisfy the definition of related party.

Ausgrid Management is a Corporations Act company that is 100% owned by the Ausgrid Operator Partnership (AOP) (ABN 78 508 211 731). Ausgrid Management is a related party of Ausgrid because Ausgrid has "control or significant influence" over Ausgrid Management. Ausgrid Management contributes to the provision of distribution services by acting as Ausgrid's agent and employing all staff that are made available to perform work in Ausgrid's business.

(ii) Alpha Distribution Ministerial Holding Corporation (ADMHC) ABN 67 505 337 385

ADMHC was formerly the NSW State Owned Corporation known as Ausgrid (the Ausgrid SOC). On 1 December 2016 the Ausgrid SOC was converted into a Ministerial Holding Corporation under section 6(1) of Schedule 7 to the Electricity Network Assets (Authorised Transactions) Act 2015. ADMHC is ultimately controlled by the State of New South Wales. ADMCH is the owner of the Ausgrid network. The State of New South Wales also holds a 49.6% interest in Ausgrid through its ownership of the ERIC Partners 1-5. This may be regarded as giving the State of New South Wales significant influence over Ausgrid. ADMHC contributes to the provision of distribution services by leasing the Ausgrid distribution network to Ausgrid Asset Partnership (ABN 48 622 605 040) (AAP) who then subleases the network to Ausgrid.

(iii) Plus ES Partnership (ABN 30 179 420 673)

The Plus ES Partnership is a partnership carried on under that name by:

(a) Blue PES Partner Pty Ltd (ACN 622 175 428) as trustee for the Blue PES Partner Trust;

(b) ERIC Alpha AUP Corporation 1 Pty Ltd (ACN 621 524 374) as trustee for the ERIC Alpha AUP Trust 1;

(c) ERIC Alpha AUP Corporation 2 Pty Ltd (ACN 621 524 454) as trustee for the ERIC Alpha AUP Trust 2;

(d) ERIC Alpha AUP Corporation 3 Pty Ltd (ACN 621 524 525) as trustee for the ERIC Alpha AUP Trust 3; and

(e) ERIC Alpha AUP Corporation 4 Pty Ltd (ACN 621 524 605) as trustee for the ERIC Alpha AUP Trust 4.

Plus ES is stapled to Ausgrid. Plus ES is a related party of Ausgrid because both Plus ES and Ausgrid are under common control of Blue Op Holdco Pty Ltd (ACN 615 227 140) as trustee for Blue Op Hold Trust (Blue Op Hold Trust) and contributes or is expected to contribute during the relevant period to the provision of distribution services by providing certain testing, electrical and fibre and metering services. These services are explained in further detail in the answer to 27.3.

(iv) Plus ES Management 1 Pty Ltd (PlusES M1) ACN 622 269 907.

Plus ES M1 is a Corporations Act company that is 100% owned by Plus ES. Plus ES M1 is a related party to Ausgrid because both Plus ES M1 and Ausgrid are under common control of Blue Op Hold Trust. Currently employees of Ausgrid Management Pty Ltd are being made available to Plus ES through a labour services agreement between AOP and Plus ES. However it is anticipated that alternate resourcing arrangements will be entered into between Ausgrid Management Pty Ltd and Plus ES M1 in relation to employees of Ausgrid Management who perform work for Plus ES. If this occurs Plus ES M1 would be considered to contribute to the provision of distribution services through the arrangements identified in answer to 27.3.

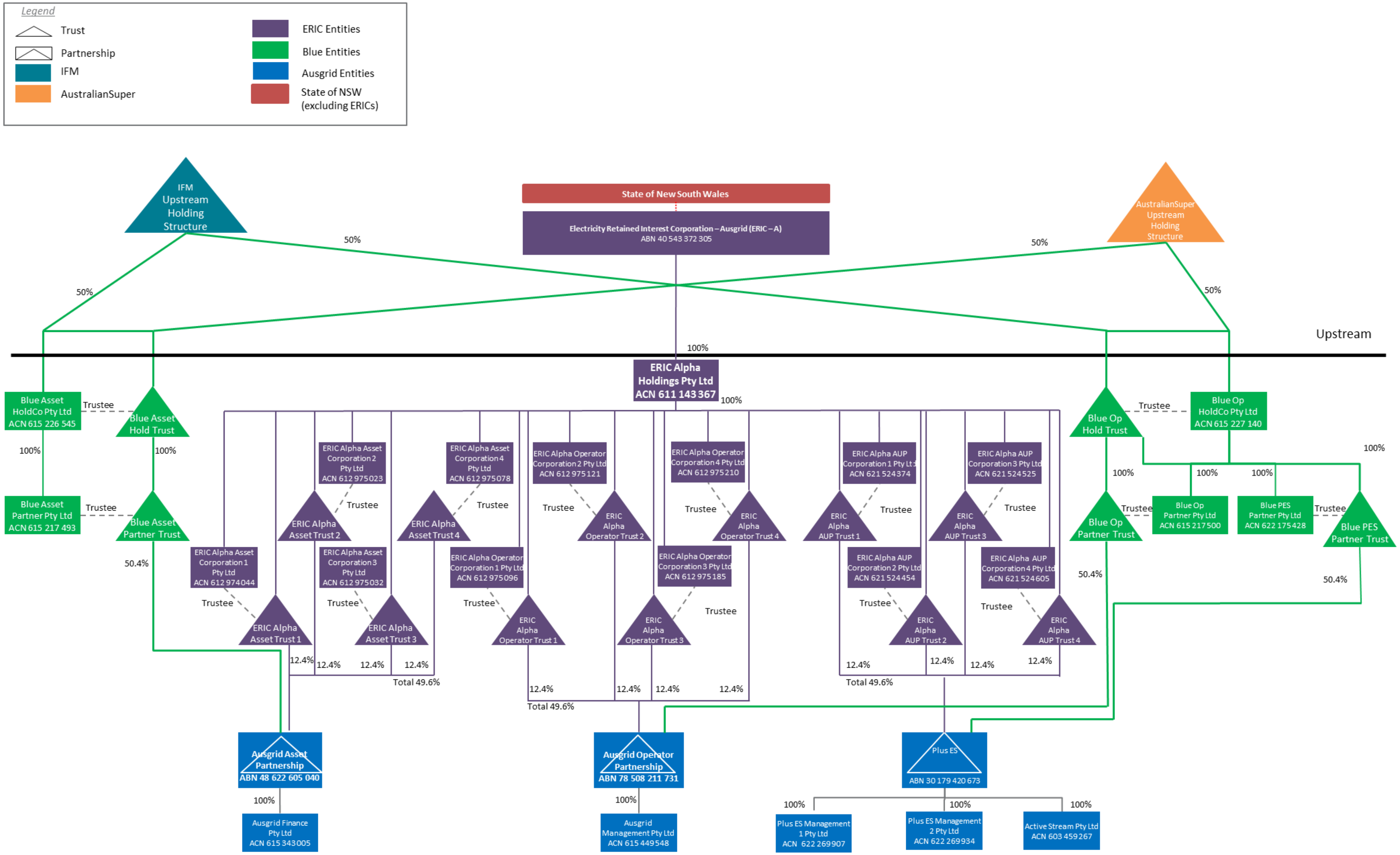
In relation to 27.1(b,) the following entities have the capacity to determine the outcome of Ausgrid's financial and operating policies:

Blue Op Partner Pty Ltd (ACN 615 217 500) as trustee for the Blue Op Partner Trust (Blue Op Partner) is a vehicle which holds 50.4% partnership interest in Ausgrid and directors appointed by Blue Op Partner have the capacity to determinate Ausgrid's financial and operating policies by settling Ausgrid's business plan and budget. It is jointly owned by IFM Investors and Australian Super through a number of interposed entities.

Blue Op Holdco Pty Ltd (ACN 615 227 140) as trustee for Blue Op Hold Trust (Blue Op Hold Trust). Blue Op Hold Trust holds 100% of the issued units in Blue Op Partner. It is jointly owned by IFM Investors and Australian Super through a number of interposed entities.

27.2 Provide a diagram of the organisational structure depicting the relationships between all the entities identified in the response to paragraph 27.1.

Figure 2. Ausgrid corporate structure



27.3 Identify:

(a) all arrangements or *contracts* between *Ausgrid* and any of the other entities identified in the response to paragraph 27.1 currently in place or expected to be in place during the period 2017-18 to 2023-24 which relate directly or indirectly to the provision of distribution *services*; and

(b) the service or services that are the subject of each arrangement or contract.

There are (7) contracts between Ausgrid and the Plus ES Partnership which are captured by 27.3(a) these and the services that are the subject are:

Current Contracts

1. Distribution Network Lease (DNL) between Alpha Distribution Ministerial Holding Corporation and Ausgrid Asset Partnership (AAP) and Sub Lease and Access Agreement (Sublease) between AAP and AOP dated 1 December 2016. The Ausgrid network including all land holding are held under lease by AAP from ADMHC and sublease by AOP from AAP which enable Ausgrid to operate the Ausgrid network.
2. Management Agreement between Ausgrid Management Pty Ltd, AAP and AOP, 26 October 2016. This agreement provides for Ausgrid Management Pty Ltd to be appointed as agent of AAP and AOP and to provide employment services under which it makes each employee available to AOP for the carrying out of its business.
3. Labour Services Agreement between Ausgrid Operator Partnership and Plus ES dated 21 December 2017. Under this agreement Ausgrid provides labour services to Plus ES prior to alternate resourcing arrangements being made between Ausgrid Management Pty Ltd and Plus ESM1.
4. Testing Services Agreement between Ausgrid and Plus ES. 1 January 2018. Under this agreement Plus ES provides chemical testing services, calibration services, electrical testing services and consulting services relating to the various testing services to support Ausgrid's operation and maintenance of its electricity network.
5. Electrical and Fibre Services Agreement between Ausgrid and Plus ES- 1 January 2018. Under this non-exclusive agreement Plus ES provides services to relating to the build and maintenance of electrical and fibre optic networks.
6. Metering Services Agreement between Ausgrid and Plus ES to support the provision by Ausgrid of certain metering related standard control services.[10]
7. Metering Services Agreement between Ausgrid and Plus ES to support the provision by Ausgrid of certain metering related alternative control services.[11]

27.4 For each service identified in the response to paragraph 27.3(b):

(a) provide:

(i) a description of the process used to procure the service; and

(ii) supporting documentation including, but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, *contracts* between *Ausgrid* and the relevant provider;

See answer to 27.4(b) below.

[10] This contract is expected to be entered into by or around 30 April 2018
[11] This contract is expected to be entered into by or around 30 April 2018

(b) explain:

(i) why that service is the subject of an arrangement or *contract* (i.e. why it is outsourced) instead of being undertaken by *Ausgrid* itself;

(ii) whether the services procured were provided under a standalone *contract* or provided as part of a broader operational agreement (or similar);

(iii) whether the services were procured on a genuinely competitive basis and if not, why; and

(iv) whether the service (or any component thereof) was further outsourced to another provider.

Please see answers set out in the following table.

Table 33. 2014/15 Disposals

Contract	(a)(i) description of process used to procure services	(a)(ii) supporting documentation including but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, contracts between Ausgrid and the relevant provider.	(b)(i) explain why that service is the subject of an arrangement or contract instead of being undertaken by Ausgrid itself.	(b)(ii) explain whether the services procured were provided under a standalone contract or provided as part of a broader operational agreement of similar.	(b)(iii) whether the services were procured on a genuinely competitive basis and if not, why.	(b(iv) whether the service (or any component thereof) was further outsourced to another provider.
Distribution Network Lease between Alpha Distribution Ministerial Holding Corporation (The State body which owns the land and assets which comprise the Ausgrid network) and Ausgrid Asset Partnership **Sublease Deed and Access Agreement between AAP and Ausgrid Operator Partnership[12].**	As part of the NSW Government's Long Term Lease Transaction of the Ausgrid network, the Ausgrid network (land and assets) was leased by ADMHC under the Distribution Network Lease to the Ausgrid Asset Partnership. The Ausgrid network was in turn subject to a sublease and access agreement between the Ausgrid Asset Partnership and the Ausgrid Operator Partnership.	Not applicable	The Ausgrid network is owned by the Alpha Distribution Ministerial Holding Company, the successor of the former Ausgrid State Owned Corporation. ADMHC lease the network land and assets to AAP who in turn subleases them to AOP who operates the Ausgrid network.	The Distribution Network Lease and the Sublease and Access Deed were part of a range of transaction documents at the time of the Long Term Lease Transaction, but are essentially stand-alone documents.	See answer to (a)(i)	Not applicable

[12] Note: ADMHC, AAP and AOP and the partners of those partnerships are also parties to a Sub Lease Deed. That Deed relates to the exercise of powers and functions between the parties under the Distribution Network Lease and the Sublease between AAP and AOP but it does not directly or indirectly relate to the provision of distribution services.

Contract	(a)(i) description of process used to procure services	(a)(ii) supporting documentation including but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, contracts between Ausgrid and the relevant provider.	(b)(i) explain why that service is the subject of an arrangement or contract instead of being undertaken by Ausgrid itself.	(b)(ii) explain whether the services procured were provided under a standalone contract or provided as part of a broader operational agreement of similar.	(b)(iii) whether the services were procured on a genuinely competitive basis and if not, why.	(b(iv) whether the service (or any component thereof) was further outsourced to another provider.
Management Agreement between Ausgrid Management Pty Ltd and Ausgrid Asset Partnership and Ausgrid Operator Partnership	The management agreement was put in place as part of the Long Term Lease transaction of the Ausgrid network.	Not applicable	Ausgrid Management Pty Ltd is the employer of the staff utilised by AOP to operate the Ausgrid network. The management agreement provides for Ausgrid Management Pty Ltd to be appointed as agent of AAP and AOP and to provide employment services under which it makes each employee available to AOP for the carrying out of its business.	The Management Agreement is part of a range of transaction documents put in place at the time of the Ausgrid Long Term Lease Transaction, but are essentially stand-alone documents.	The services provided are essentially on a cost pass through basis.	No
Labour Services Agreement between Ausgrid (AOP) and Plus ES	There was no formal procurement process. The arrangements were entered into in December 2017 as part of the creation of Plus ES as an Ausgrid affiliate to meet the requirements of the AER ringfencing guidelines by 1 January 2018.	There was no formal procurement process.	The arrangement is an interim arrangement to allow for more formal industrial arrangements to be put in place regarding employees of Ausgrid Management Pty Ltd (who have been provided to Ausgrid DNSP under the Management Agreement described above) being provided to Plus ES M1. This arrangement provides the labour services required by Plus ES to carry out its business.	Services are provided under a standalone contract.	The services provided are essentially on a cost pass through basis ie remuneration plus on-costs incurred by AOP in relation to the employment of each employee.	No

Contract	(a)(i) description of process used to procure services	(a)(ii) supporting documentation including but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, contracts between Ausgrid and the relevant provider.	(b)(i) explain why that service is the subject of an arrangement or contract instead of being undertaken by Ausgrid itself.	(b)(ii) explain whether the services procured were provided under a standalone contract or provided as part of a broader operational agreement of similar.	(b)(iii) whether the services were procured on a genuinely competitive basis and if not, why.	(b(iv) whether the service (or any component thereof) was further outsourced to another provider.
Testing Services Agreement between Ausgrid and Plus ES	There was no formal procurement process. The contracts were entered at the same time as the creation of Plus ES as an Ausgrid affiliate to meet the requirements of the AER ringfencing guidelines by 1 January 2018. The most timely and efficient approach to ensure continuity of these services to the Ausgrid DNSP was to put in place these arrangements.	There was no procurement process for the reasons set out in answer to (a)(i).	The services the subject of this contracts were previously undertaken by Ausgrid itself as part of its operation and maintenance of its electricity network and were also provided to third parties. Upon creation of the Plus ES affiliate the staff and resources associated with the provision of these services, were transferred in the case of resources or made available in the case of staff to Plus ES. This means that Ausgrid DNSP no longer has the internal capability to carry out these services itself.	Services are provided under a stand-alone contract.	There was no formal procurement process as set out in answer to (a)(i) Notwithstanding this, the commercial terms and prices for the services in the agreement are considered to be commercial arms length terms	No
Electrical and Fibre Services Agreement between Ausgrid and Plus ES	As above	As above	As above	As above	As above	No
Metering Services Agreement between Ausgrid and Plus ES (Standard Control Services)	There was no formal procurement process. The agreements are part of the arrangement for the creation of Plus ES as an affiliate to meet the requirements of the AER ringfencing guidelines.	There was no formal procurement process for the reasons set out in answer to (a)(i) and (b)(i).	The Plus ES affiliate has taken over Ausgrid's metering business which had provided both Type 1-4 metering and Type 5-7 metering services and associated ancillary services. Ausgrid DNSP is however still required by the National Electricity Rules to be the metering	Services are provided under a stand-alone contract.	There was no formal procurement process as set out in answer to (a)(i). Notwithstanding this, the commercial terms and prices for the services in the agreement are	Yes

Contract	(a)(i) description of process used to procure services	(a)(ii) supporting documentation including but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, contracts between Ausgrid and the relevant provider.	(b)(i) explain why that service is the subject of an arrangement or contract instead of being undertaken by Ausgrid itself.	(b)(ii) explain whether the services procured were provided under a standalone contract or provided as part of a broader operational agreement of similar.	(b)(iii) whether the services were procured on a genuinely competitive basis and if not, why.	(b(iv) whether the service (or any component thereof) was further outsourced to another provider.
			coordinator for certain distribution and transmission wholesale metering, network boundary and zone metering points in the NEM, as well Type 7 (unmetered) metering installations. As the capability to provide the associated metering provision and metering data provision services is now with the Plus ES affiliate, this contract provides the capability for Ausgrid to continue to provide those services and meet its obligations as a metering coordinator. Whilst Plus ES provides the services required by Ausgrid DNSP to meet its obligations, at this point integrated systems are required to provide services. In addition Ausgrid does not consider that any external party that would have the capability to provide these services and in the time frame required for the creation of the Ausgrid affiliate.		considered to be commercial arms length terms.	
Metering Services Agreement between Ausgrid and Plus ES (Alternative Control	As above	As above	The Plus ES affiliate has taken over Ausgrid's metering business which had provided both Type 1-4 metering and Type 5-7 metering services and associated ancillary services. Ausgrid DNSP is however still	As above	There was no procurement process for the reasons set out in answer to (a)(i). There was no procurement	Yes

Contract	(a)(i) description of process used to procure services	(a)(ii) supporting documentation including but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, contracts between Ausgrid and the relevant provider.	(b)(i) explain why that service is the subject of an arrangement or contract instead of being undertaken by Ausgrid itself.	(b)(ii) explain whether the services procured were provided under a standalone contract or provided as part of a broader operational agreement of similar.	(b)(iii) whether the services were procured on a genuinely competitive basis and if not, why.	(b(iv) whether the service (or any component thereof) was further outsourced to another provider.
Services)			required by the National Electricity Rules to be the metering coordinator for Type 5-6 metering services until all meters have “churned” to Type 4 meters. This Contract relates to the part of metering and related services that are classified as alternative control services, being the provision on Type 5-6 metering services and associated ancillary metering services. Plus ES provides part of the services required by Ausgrid DNSP to meet its obligations (essentially the front end service) whilst Ausgrid provides other aspects such as the B2B systems and service, at this point integrated systems are required to provide services and it is anticipated that Plus ES will continue to provide these services whilst Ausgrid DNSP has continuing type 5-6 metering obligations. Ausgrid does not consider that any external party would have the capability to provide these services, being services that are largely transitioning out of the NEM, in the time frame that was required for the creation of the Ausgrid affiliate.		process as set out in answer to (a)(i). Notwithstanding this, the commercial terms and prices for the services in the agreement are considered to be commercial arms length terms	

28. VEGETATION MANAGEMENT COMPLIANCE

28.1 Provide compliance *audits* of *vegetation management* work conducted by *Ausgrid* during the *current regulatory control period*.

See Attachment RIN10 (Vegetation compliance audit).

29. CORPORATE STRUCTURE

29.1 Provide charts that set out:

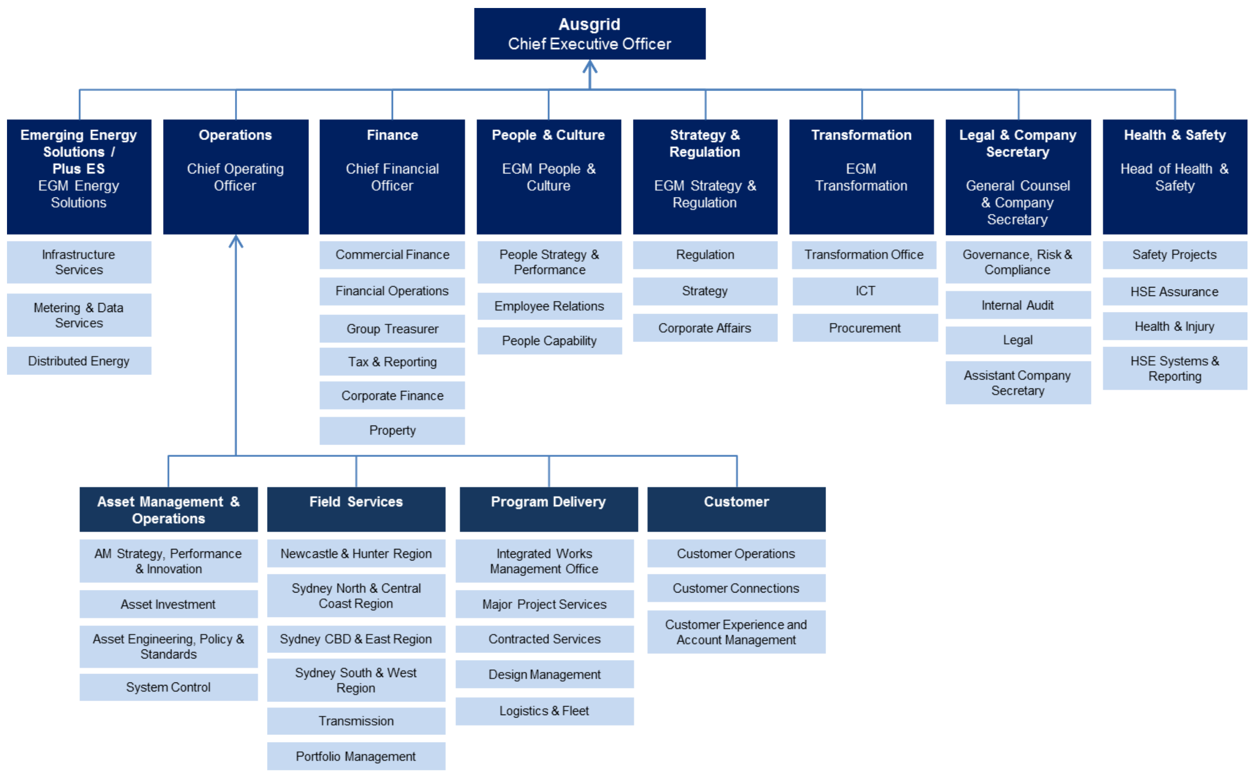
(a) the group corporate structure of which *Ausgrid* is a part; and

See our response to 27.2 above for a chart of our corporate structure.

(b) the organisational structure *of Ausgrid*.

The following diagram shows Ausgrid's organisational structure.

Figure 3. Ausgrid organisational structure

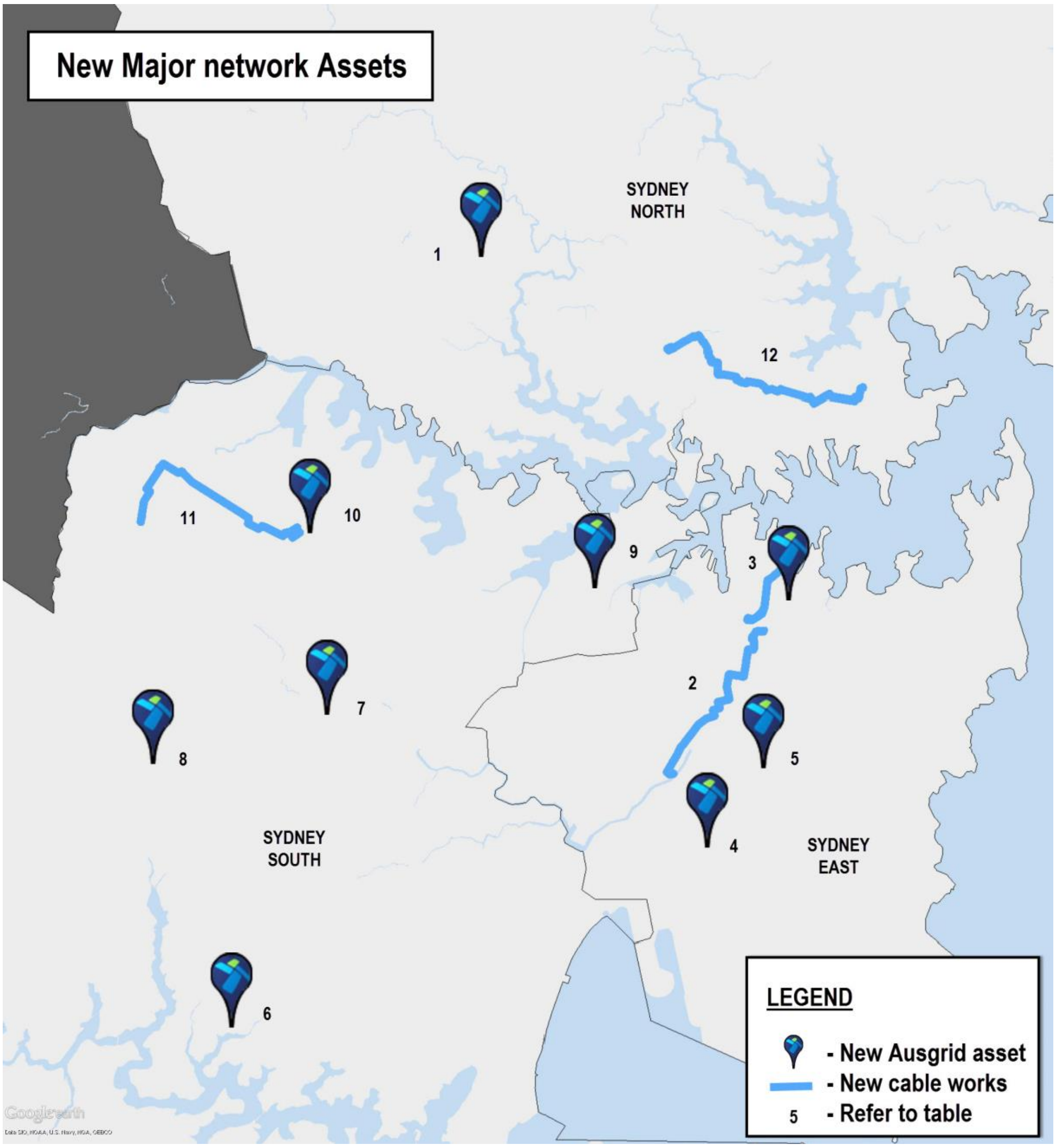


30. FORECAST MAP OF DISTRIBUTION SYSTEM

30.1 Provide a forecast map of *Ausgrid'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*.

The following map indicates the location of all new major network assets proposed to be constructed by Ausgrid over the forthcoming regulatory control period. For the purposes of this response, major network assets have been defined as those with expenditure over $25 million during the 2019-24 period.

Figure 4. Forecast map of distribution system



The following table details the major projects and associated major new network assets.

Table 34. Major capex projects during 2019-24

Project (Map reference)	Project ID	Description
1	ARA_01.0007A	New 132/33kV Macquarie Subtransmisson Substation (Conditional Project)
2	ARA_01.1.0028A	Replace 132kV Feeders 9SA & 92P

Project (Map reference)	Project ID	Description
3	ARA_02.1.0127	Decommission 33/11kV City East Zone Substation
4	ARA_03.1B.0017	New 132/11kV Mascot East and decommission Mascot
5	ARA_03.1C.0006 & 0030	New 132/11kV Alexandria North Zone Substation and decommission Zetland Zone Substation
6	ARA_04.1.0029	Replace 33kV Switchgear Peakhurst Subtransmisson Substation
7	ARA_04.3A.0007 & 0001	New 132/11kV Strathfield and Decommission Enfield
8	ARA_04.3A.0014	New 132/11kV Greenacre and Decommission Zone Substation
9	ARA_04.4.A.0005	New 33kV Switchgear Rozelle Subtransmission Substation
10	ARA_04.4.B.0002	Replace 11kV Switchgear Concord Zone Substation
11	ARA_04.4.C.0008	Replace 33kV Feeders Homebush-Auburn/Lidcombe
12	ARA_05.1.0014	Replace 132kV Feeders 9E4/4 & 925/4 Willoughby-Cremorne

31. TRANSITIONAL ISSUES

31.1 Provide information on transitional issues (expressly identified in the *NER* or otherwise) which *Ausgrid* 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:

(a) the transitional issue;

(b) what has caused the transitional issue;

(c) how the transitional issue impacts on *Ausgrid*; and

(d) how *Ausgrid* considers the transitional issue could be addressed.

The term ‘transitional issue’ is not defined in the RIN. Ausgrid however have identified the following issues which it considers (a) have an impact on Ausgrid (though materiality cannot be determined at this stage) or (b) are of relevance but do not strictly qualify as a ‘transitional issue’ in the sense that this term in used in clause 31.1 of the RIN.

Issue of impact

Ausgrid considers the following issue does have an impact of its preparation of the 2019-24 regulatory proposal however the materiality of the issue is not susceptible to quantification at this stage as a key outcome (i.e. the outcome of the 2018 rate of return guideline) is not known at the time of submitting the regulatory proposal.

Application of the current 2013 Rate of Return Guideline and proposed amendment on binding rate of return guideline

We note the AER is currently undertaking a review of its rate of return guideline. We understand that the current rate of return guideline (i.e. December 2013 version) applies to the making of Ausgrid’s 2019-24 distribution determination, as required by clause 11.93 of the National Electricity Rules.

Irrespective of this current position, we note that on 2 March 2018, the COAG Energy Council published a bulletin and proposed legislation outlining its proposed amendment to the National Electricity Laws, National Gas Laws and consequential changes to the National Electricity Rules and National Gas Rules to effectively have the 2018 Rate of Return

Guideline apply to the AER's making of its distribution determination for Ausgrid for 2019-24. Whilst COAG stated that it expects the bill to be enacted by December 2018 but:

The draft Bill does not represent government policy and has not been endorsed by the Energy Council or any Government participating in the national process at this stage.

Given the above and the unclear status of this Bill at the time of submitting Ausgrid's 2019-24 regulatory proposal, Ausgrid has prepared its regulatory proposal based on the current rate of return guideline (2013 Guideline) and the current applicable National Electricity Rules relating to the operation of this guideline and Ausgrid's proposed rate of return for the 2019-24 period.

Issues of relevance

Ausgrid considers the following issues would be of relevance but they do not strictly qualify as 'transitional issue' in the sense that this term is used in clause 31.1 because:

- They do not impact on Ausgrid's 2019-24 regulatory proposal per se and consequently the AER's distribution determination on this proposal.
- The process on how these issues are to be dealt with by the AER is set out in the National Electricity Rules (and/or AER's position paper as relevant).

Our reasons are set out below.

1. **Smoothing of revenue from AER's final remitted decision for 2014-19:** Ausgrid notes that the AER is in the process of consulting on its remitted decision with respect to cost of debt and forecast opex for the 2014-19 period for Ausgrid, following the conclusion of the merits review process. The remaking of the 2014-19 distribution determination is separate from the making of the distribution determination for the 2019-24 period. However the revenue shortfall/surplus (i.e. difference between revenue recovered in 2014-19 and revenue allowed under the remitted decision) would need to be returned/recovered during the 2019-24 period and how this revenue is 'smoothed' over the 2019-24 period is subject to a different decision to be made by the AER under the National Electricity Amendment (Participant derogation – NSW DNSPs Revenue Smoothing) Rule 2017 No.6. The AEMC decided that such decision should be a separate decision so as not to interfere with the AER's making of a distribution determination. Consequently, whilst the making of the remitted decision for 2014-19 and the recovery of any consequential revenue are relevant considerations for Ausgrid, we understand they do not impact on the AER's making of a distribution determination for the 2019-24 period per se.

2. **Final amended Service Target Performance Incentive Scheme:** We note that the AER is in the process of amending this guideline and a final guideline is scheduled to be published in June 2018. The AER noted in its final Framework and Approach for Ausgrid for the 2019-24 control period that it intends to apply the amended STPIS guideline if that guideline is published in time for the making of the final determination. Based on the AER's timeline for the finalisation of the amended STPIS guideline, Ausgrid does not anticipate any transitional issues regarding the application of the SPTIS guideline. Irrespective, the current STPIS would apply to Ausgrid if a revised STPIS is not published in time for the making of the 2019-24 determination. If a revised guideline is however published in time, the AER will consider its application to Ausgrid for the 2019-24 period as noted in the AER's final Framework and Approach paper.

   We also note the AER is consulting on the Distribution Reliability Measures Guideline and expect this guideline will also be finalised around the same time as the amended STPIS guideline as these guidelines are inter-related. Similarly, we anticipate that the

AER would also consider the application of this guideline as part of its distribution determination for Ausgrid for 2019-24.

ASSURANCE REQUIIREMENTS

32. AUDIT AND REVIEW REPORTS

32.1 Provide the *audit report* and *review reports* as applicable, prepared in accordance with the requirements set out in Appendix C.

See Attachment RIN17 (RIN Audit Report).

32.2 Provide all reports from the *auditor* to *Ausgrid's* management regarding the *audit* review and/or *auditors*' opinions or assessment.

See Attachment RIN17 (RIN Audit Report).

Ausgrid confirms it has provided all Auditor reports.

OTHER INFORMATION

33. CONFIDENTIAL INFORMATION

33.1 This clause applies to any information *Ausgrid* provides:

(a) in response to Schedule 1;

(b) in a *regulatory proposal* for the *forthcoming regulatory control period* (a Proposal)

(c) in a revision or amendment to a Proposal; and

(d) in a submission *Ausgrid* makes regarding a Proposal or a revised or amended Proposal; (together, *Ausgrid's* Information).

Noted.

33.2 If *Ausgrid* wishes to make a claim for confidentiality over any of *Ausgrid'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.

The completed confidentiality templates for the information we consider confidential is provided at Attachment 1.01 (Confidentiality claims). These completed templates provide comprehensive details of our claims.

33.3 Provide any details of a claim for confidentiality in response to paragraph 33.2 at the same time as making the claim for confidentiality.

The completed confidentiality templates for the information we consider confidential is provided at Attachment 1.1.1 (Confidentiality claims). These completed templates provide comprehensive details of our claims.

34. COMPLIANCE WITH SECTION 71YA OF THE NEL

34.1 Provide a statement attesting that:

(a) Where any expenditure or cost is has been incurred or is forecast to be incurred by *Ausgrid,* as a result of or incidental to a review under Division 3A – *Merits review and other non-judicial review* – of the NEL:

(i) Ausgrid has not included any of that expenditure or cost, or any part of that expenditure or cost, in its capital or operating expenditures for a network revenue or pricing determination; and

(ii) Ausgrid has not recovered any of that expenditure or cost, or any part of that expenditure or cost, from end users; and

(iii) Ausgrid has not sought to pass through any of that expenditure or cost, or any part of that expenditure or cost, to end users; or

(b) Where no expenditure or cost has been incurred or is forecast to be incurred by *Ausgrid,* as a result of or incidental to a review under Division 3A – *Merits review and other non-judicial review* – of the *NEL*:

(i) No such expenditure or cost has been incurred or is forecast to be incurred.

Ausgrid confirms that no expenditure or costs that we have incurred as the result of or incidental to the merits review and judicial review of the AER's final determination for Ausgrid for 2014-19, published in April 2015:

- Has been included in any expenditure or costs, or any part of that expenditure or costs, in Ausgrid's capital or operating expenditure included in the regulatory proposal for the regulatory control period 2019-2024; and
- Has been recovered from end users; and
- Has not been sought by Ausgrid as pass through costs to end users.

In addition, no such expenditure has been forecast to be incurred in the 2019-24 period.

35. IDENTIFICATION OF CERTAIN COSTS IN ACTUAL CAPITAL AND OPERATING EXPENDITURE

35.1 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 Ausgrid has incurred as a result of, or incidental to, a review under Division 3A – Merits review and other non-judicial review – of the NEL.

The table below shows the costs incurred as the result of, or incidental to, the merits review, (and response to the AER's judicial review application), of the AER's final determination for Ausgrid for 2014-19, published in April 2015.

Table 35. Costs relating to judicial review, ($ nominal)

Description	2014/15	2015/16	2016/17	2017/18	Total
Costs incurred	216,204	0	933,822	58,730	1,208,757