

**Regulatory Information Notice (RIN)
Issued Under Division 4 of Part 3 of
National Electricity (New South Wales)
Law**

**Endeavour Energy
Response to Schedule 1 of the RIN (VERSION 15 May)**

Submission date: 30 May 2014

CONTENTS

Purpose	3
1. Provide Information	4
2. Classification of Services	13
3. Control Mechanisms	14
4. Step Changes.....	15
5. Capital Expenditure	21
6. Replacement Capital Expenditure Modelling	32
7. Augmentation Capital Expenditure Modelling	34
8. Demand and Customer Number Forecasts	46
9. Connections Expenditure Requirements	55
10. Operating and Maintenance Expenditure	56
11. Risk Management and Insurance	66
12. Alternative Control Services and Other Activities	73
13. Fee Based and Quoted Alternative Control Services	78
14. Metering Alternative Control Services.....	81
15. Public Lighting Alternative Control Services	84
16. Economic Benchmarking	86
17. Provisions.....	88
18. Forecast Price Changes.....	89
19. Related Party Transactions.....	91
20. Proposed Contingent Projects	93
21. Non-Network Alternatives	95
22. Efficiency Benefit Sharing Scheme	98
23. Service and Quality	100
24. Shared Assets	103
25. Revenues and Prices for Standard Control Services.....	104
26. Indicative Impact on Annual Electricity Bills	105
27. Regulatory Asset Base.....	106
28. Depreciation Schedules	107
29. Corporate Tax Allowance.....	109
30. Corporate Structure.....	111
31. Forecast Map of Distribution System	112
32. Audit Reports.....	113
33. Board Resolution.....	114
34. Transitional Issues	115
35. Confidential Information	116

Purpose

The AER requires Endeavour Energy to provide the information specified in Schedule 1 of the RIN, audited in accordance with Appendix C of the RIN.

This document is Endeavour Energy's response to the information sought in Schedule 1.

1. Provide Information

1.1 Provide the information required in each Regulatory template in the Microsoft Excel Workbooks attached at Appendix A of the RIN.

The Microsoft Excel Workbooks have been completed and are provided at Attachments RIN.1-3. The Workbooks have been completed in accordance with:

- a) the RIN;
- b) the instructions in the Microsoft Excel Workbooks attached at Appendix A of the RIN;
- c) the principles and requirements in Appendix E of the RIN; and
- d) the service classifications set out in the framework and approach paper.

1.2 Provide a Basis of Preparation demonstrating Endeavour Energy has complied with the RIN.

A Basis of Preparation has been prepared and is provided at Attachment RIN.4. The Basis of Preparation has been prepared for information other than forecast information, in respect of:

- a) The information in each Regulatory template in the Microsoft Excel Workbooks attached at Attachments RIN.1-3; and
- b) Any other information prepared in accordance with the requirements of the RIN.

1.3 Provide any other supporting information or documentation that is directly relevant to our Regulatory proposal.

Endeavour Energy has provided the following additional information that is directly relevant to our Regulatory proposal:

Item No	Description
0.01	Customer overview: plain English summary - Affordable, safe and reliable electricity
0.02	Delivering efficiencies for our customers
0.03	Addressing the capex and opex objectives, criteria and factors
0.04	Escalation factors affecting expenditure forecasts (CEG)
0.05	Labour cost escalators for NSW, the ACT and Tasmania (Independent Economics)
0.06	Board certified key assumptions
0.07	Cost Allocation Methodology
0.08	Expenditure Forecasting Methodology
0.09	ICT Investment Plan
0.10	Proposed Connection Policy
0.11	Endeavour Energy Distribution Business Benchmarking Study (Huegin)
0.12	Addressing the benchmarking factor for capex and opex
0.13	Economic interpretation of Clauses 6.5.6 and 6.5.7 of the NER (NERA report)
0.14	Endeavour Energy STPIS Proposal
0.15	Endeavour Energy Negotiating Framework - Negotiated Distribution Services

0.16	Public Lighting Price List
0.17	Metering Model and prices
0.18	Ancillary Network Services Proposed Fees
0.19	Confidentiality Claim
0.20	Reference table for Rules Compliance
2.01	Customer Engagement Plan
2.02	Customer Engagement Study Qualitative and Quantitative Full Report - August 2013
2.03	Customer Engagement Survey Qualitative Summary Report - May 2013
2.04	Customer Engagement Survey Quantitative Summary Report - July 2013
2.05	Customer Priorities Data Review (IPSOS)
2.06	Consumer Engagement Report - April 2014
2.07	Networks NSW Social Media Campaign - YourPowerYourSay
2.08	Peak Consumer Group Forum Report (with appendices)
2.09	Local Council Engagement Report
2.10	Retailers' Forum Engagement Report and Presentation
2.11	Stakeholder Correspondence Summary Report
3.01	Endeavour Energy classification proposal
4.01	RFM
4.02	PTRM – Substantive Proposal
4.03	EBSS model for 2010-2014
4.04	Forecast Customer Numbers, Energy Consumption and Billed Demand
4.05	Energy Forecasting Methodology Flowchart
4.06	Review of post modelling adjustments to the NSW DNSPs long term energy forecasts
4.07	Frontier Economics recommendations report on forecasting (including cover letter)
4.08	NIEIR Macroeconomic Projections December 2013
4.09	NIEIR Price & Elasticity Projections December 2013
4.10	Endeavour Energy Pass Through Event Proposal
5.01	Network Supply Strategy 2014-19
5.02	Network Management Plan
5.03	SAMP
5.04	SAMP Delivery Plan
5.05	TNPR
5.06	SARP
5.07	Augex model summary

5.08	Repex model review report
5.09	Annual Licence Compliance Reports (4)
5.10	Procurement strategy
5.11	Risk Management Plan
5.12	Company Procedure GFC 0056 - Investment Evaluations Manual
5.13	Company Policy 9.2.1 - Network Planning
5.14	Company Procedure GAM0035 - Major Projects Formulation and Approval
5.15	Company Policy GAM0013 - SAMP Project Management Capital Project Change Control
5.16	Distribution Annual Planning Report - 2013
5.17	Capital expenditure for previous, current and forecast period
5.18	Branch Procedure NFB0010 - Network Demand Forecasting – Summer and Winter Peak Demand Forecast Process
5.19	Review of Endeavour Energy's method for peak demand forecasts (Spatial Peak)
5.20	Escalation Factors Endeavour Energy
5.21	Growth Servicing Strategy
5.22	Sample Business Case - Marsden Park Industrial Area
5.23	North West Sector Area Plan
5.24	South West Sector Area Plan
5.25	Greenfield Zone Substation Business Cases\
5.26	Distribution Works Program (including DSR)
5.27	Reliability Works Program
5.28	Reliability Plan
5.29	Quarterly Licence Compliance reports (19)
5.30	Reliability and Performance Licence Conditions for Electricity Distributors effective 1 July 2014
5.31	KPMG Prudence and efficiency review for Endeavour Energy's 2014-19 ICT Submission
5.32	Network Technology Strategy
5.33	FSC Strategy
5.34	Demand Management Strategy 2014-19
6.01	Network Reform Savings Register
6.02	Challenge and Compete Savings Register
6.03	Company Policy 6.11 - Capital Expenditure Measurement and Control
6.04	Company Procedure GFC0005 - Capital Expenditure
6.05	Company Policy 6.9 - Capital Expenditure - Overhead Calculation
6.06	Company Procedure GFC0034 - Budgeting and Forecasting

6.07	Company Policy 6.31 - Budgeting and Forecasting
6.08	Capitalised Overhead models (2014-15 to 2018-19)
6.09	Maintenance unit rate model
6.10	Allocation process (Methodology document on giving effect to the CAM)
6.11	Network Maintenance Implementation Plan
6.12	AER decision-Application for a retail project event nominated cost pass through
6.13	NSW DNSPs Review of regulatory treatment of risk (EY)
6.14	Operating expenditure for previous, current and forecast period
6.15	Operating expenditure – fixed vs. variable
7.01	CEG - WACC estimates, a report for NSW DNSPs
7.02	CEG - Debt transition consistent with the NER and NEL
7.03	CEG - Efficiency of staggered debt issuance
7.04	CEG - Transition to a trailing average approach
7.05	UBS Advice to Networks NSW - October 2013
7.06	Kanangra - Credit Ratings for NSPs - 28 June 2013
7.07	Incenta - Debt raising costs - Endeavour
7.08	Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, UNDERSTANDING ASSET PRICES
7.09	NERA - The Fama-French Three-Factor Model - Oct 2013
7.10	SFG - Alternative versions of the dividend discount model and the implied cost of equity
7.11	SFG - Dividend discount model estimates of the cost of equity - 19 June 2013
7.12	NERA - The market size and value premiums - June 2013
7.13	NERA - The Market Risk Premium, Analysis in response to the AER's draft guideline - 11 Oct 2013
7.14	CEG - Estimating the return on the market - 28 June
7.15	CEG - Estimating the E[R _m] in the context of recent regulatory debate
7.16	SFG - Cost of equity in the Black Capital Asset Pricing Model - May 2014
7.17	NERA - Estimates of the zero beta premium - 27 June 2014
7.18	SFG - Equity beta - May 2014
7.19	SFG - Regression-based estimates of risk parameters for the benchmark firm
7.20	CEG - Information on equity beta from US companies
7.21	CEG - Equity beta issues paper International comparators
7.22	Comparison of OLS and LAD regression techniques for estimating beta - 26 June 2013
7.23	The Vasicek adjustment to beta estimates in the Capital Asset Pricing Model
7.24	Assessing the reliability of regression-based estimates of risk

7.25	SFG letter - Water utility beta estimation - 28 October 2013
7.26	Endeavour Energy Gamma Proposal
7.27	SFG - An appropriate regulatory estimate of gamma
7.28	NERA - Imputation Credits and Equity Prices and Returns
7.29	SFG - Updated dividend drop-off estimate of theta - 7 June 2013
7.30	NERA - The Payout Ratio - June 2013
7.31	Hathaway - Imputation credit redemption data from the ATO 1988-2011
7.32	NSW DNSP Submission on the Rate of Return consultation paper - June 2013
7.33	NSW DNSP Submission to AER on the draft Rate of Return Guideline 11 Oct 2013
7.34	NNSW response to AER letter on cost of debt averaging periods 27 Feb 2014
8.01	Public lighting code - NSW 2006 Public Lighting Code
8.02	Public lighting proposal
8.03	Public lighting management plan
8.04	Public lighting modelling methodology
8.05	Public lighting model
8.06	Review of Endeavour Energy's Proposed Metering Tariff Arrangements for 2014-19 (Energeia)
8.07	Endeavour Energy's Approach to Pricing Types 5 & 6 Metering Services
8.08	KPMG report on Endeavour Energy ANS approach
8.09	ANS Fee Methodologies
8.10	Alternative Control Services true up mechanism
9.01	Compliance Model
9.02	Assigning customers to tariff classes
9.03	Compliance with Control Mechanisms

In addition to our regulatory proposal, the Reset RIN attachments are as follows:

	Attachments
RIN.1	NSW_ACT Electricity DNSPs reset RIN templates - Consolidated information
RIN.2	NSW_ACT Electricity DNSPs reset RIN templates - Actual information
RIN.3	NSW_ACT Electricity DNSPs reset RIN templates - Estimated information
RIN.4	Reset RIN Basis of Preparation
RIN.5	PWC Audit opinion - actual financial information
RIN.6	PWC audit opinion - estimated financial information
RIN.7	TCFT audit opinion - non-financial information
RIN.8	Board Resolution
RIN.9	Confidentiality Claim

RIN.10	TCFT Audit Report
RIN.11	Endeavour Energy response to the RIN
RIN.12	Endeavour Energy Statutory Declaration
Schedule 1 and 2 supporting attachments	
A	Procurement Folder for 1.5(d)
B	Schedule 1 response reference list
C	Current DRP Licence Conditions
D	Endeavour Energy Long Term Customer Numbers
E	Endeavour Energy Short Term Customer Numbers
F	AVS model - valuation of gifted assets for customer funded contestable work
G	Vegetation Management Compliance Audits
H	David A Zaman Pty Ltd Actuarial Report July 2013
I	Q12 Alternative Control Services & Other Activities - Endeavour response
J	Q13 Fee Based and Quoted Alternative Control Services - Endeavour response
K	Q14 Metering Alternative Control Services - Endeavour response
L	Q15.2 Public Lighting Inventory information
M	Q15.6 Public Lighting luminaires by type
N	Q15.7 Public Lighting Inventory information
O	DBS EISS Actuary Assessments
P	Employee Entitlements Actuary Assessments
Q	Certified Version 21 May 2013 - EE 2012 EBA Agreement
R	Contract Price Adjustment Schedule
S	Treasury Report_Feb 2014 Contract price variations
T	Endeavour Energy Structure
U	Group Structure
V	Indicative Bill impact data sources
W	Capital expenditure - as-incurred basis
X	KPMG 2013 IT Benchmarking Final Report - Endeavour Energy

1.4 Provide the applicable cost allocation methodology.

Endeavour Energy has provided the applicable cost allocation methodology at Attachment 0.07 to our regulatory proposal.

1.5 (a) Provide for the purposes of the preparation of the regulatory proposal all economic analysis used to justify expenditure.

All economic analysis used to justify expenditure is provided in the supporting attachments to our regulatory proposal.

1.5 (b) Provide for the purposes of the preparation of the regulatory proposal all consultants reports commissioned and relied upon in whole or in part .

All consultants reports commissioned and relied upon in whole or in part in the preparation of the Regulatory proposal are provided in the supporting attachments to our proposal and this RIN.

1.5 (c) Provide for the purposes of the preparation of the regulatory proposal all material assumptions relied.

Endeavour Energy has relied upon the following material assumptions detailed in the preparation of the Regulatory proposal (refer to Attachment 0.06 to the proposal):

- The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.
- Regulatory Obligations including DRP (Design Reliability and Performance) Licence Conditions are those in place at time forecasts are finalised.
- Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts adopted for the regulatory proposal.
- Replacement and maintenance (capex and opex) expenditure is based on our assessment of asset age and condition as contained in the asset management plans adopted for the regulatory proposal.
- Unit rates, real costs escalators and the inflation rate adopted are a realistic expectation of the costs of inputs in the 2014-2019 period
- The opex year 2012/13 has been adopted as the efficient base year for deriving a forecast of recurrent opex.
- The concerns of electricity consumers which must be considered by the AER are those derived from the stakeholder engagement process undertaken in accordance with the Rules.

1.5 (d) Provide for the purposes of the preparation of the regulatory proposal copies of the top ten contracts relating to the delivery of distribution services, by annual value, and any supporting information directly related to the procurement process for the services provided by these contracts (e.g. probity reports, Board minutes, tendering documents).

Details of the top ten contracts relating to the delivery of distribution services, by annual value are shown in the following table. Copies of the contravcts and any supporting information directly related to the procurement process for the services provided by these contracts are at Attachment A to the RIN.

	CONTRACT ID	CONTRACT DESCRIPTION	CONTRACTORS	EXPENDITURE (2013)	DOCUMENTS INCLUDED
1	6383/12	Delivery of Vegetation Management Services in proximity to Endeavour Energy's Overhead Network assets	ASPLUNDH TREE EXPERT ACTIVE TREE SERVICES SYDNEY METRO TREE SERVICES	\$27.9M (Note: Includes expenditure against all veg contracts for 2013 not just 6383)	1) TRC Document 2) MSA and Supply Schedules for all three businesses
2	1443/11	Establish Period Contracts to Support Delivery of the Distribution Works Program.	UEA ELECTRICAL PTY LTD TRANSELECT CONNECT INFRASTRUCTURE	\$21.7M	1) CRC Document 2) Contracts with all three suppliers
3	1540/12	Civil and Transmission Mains Work for East and West Parramatta Substation Feeders	DIONA PTY LTD	\$17.5M	1) TRC Document 2) Contract Docs

	CONTRACT ID	CONTRACT DESCRIPTION	CONTRACTORS	EXPENDITURE (2013)	DOCUMENTS INCLUDED
4	1065/08	Panel for Directional Drilling and Trenching services	INFRASTRUCTURE CONSTRUCTIONS BASTOW CIVIL CONSTRUCTIONS UEA/CLM JV DUNMAIN	\$15.2M	1) CRC Document 2) Panel Contracts will all panel members
5	1585/12	Construction of Cattai & Glenorie Overhead 33kV Transmission Line	CONNECT INFRASTRUCTURE POWERCOR AUSTRALIA	\$12.4m	1) CRC Document 2) Contract documents
6	1577/12	Performance of Civil and Overhead Works for Liverpool TS 33kV Feeders	DUNMAIN	\$10.9m	1) CRC Document 2) Contract documents
7	1074/09	The Provision for Traffic Management Services	D&D TRAFFIC MANAGEMENT DONNELLEY CIVIL TRAFFIC MANAGEMENT SERVICES WORKFORCE INTERNATIONAL	\$9.5M	1) CRC Document 2) Three contracts
8	1582/12	Augmentation and Construction of 33kV Feeders at West Tomerong and Tomerong Zone Substation	TRANSELECT	\$8.4M	1) CRC Documents
9	1458/11	Engagement of Level 2 Accredited Service Providers to Deliver the Service Mains Pilot Replacement Program	UTILITY ASSET MANAGEMENT	\$6.9M	1) CRC Document 2) Executed contract
10	1593/12	Performance of Construction Works at Cattai ZS	AVANT CONSTRUCTIONS	\$5.5M	1) CRC Document 2) Executed contract

1.5 (e) Provide for the purposes of the preparation of the regulatory proposal a table that references each response to a paragraph in Schedule 1, where it is provided in or as part of the regulatory proposal.

Attachment B of the RIN references each response to a paragraph in Schedule 1 and where it is provided in or as part of the Regulatory proposal.

1.6 Provide for each material assumption identified in the response to 1.5 (c) its source or basis, if applicable its quantum, whether & how the assumption has been applied & was taken into account and the effect or impact of the assumption on the capital and operating expenditure forecasts taking into account the actual expenditure in the current period and the sensitivity of the forecast expenditure to the assumption.

Attachment 0.06 to our regulatory proposal provides the information requested in relation to each material assumption identified in response to 1.5 (c).

1.7 Capital & operating expenditure forecasts provided in the regulatory templates must be reconciled to the ex-ante capital & operating allowances in PTRM for the next regulatory control period.

Capital and operating expenditure forecasts provided in the Regulatory templates have been reconciled to the ex-ante capital and operating allowances in the PTRM of the next regulatory control period at Attachment 4.02 to our regulatory proposal.

1.8 (a) 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 set out in the framework and approach paper, for each variation or departure explain the reasons for the variation or departure including why it is appropriate.

Endeavour Energy's Regulatory proposal does not vary or depart from the application of any component or parameter of the capital efficiency sharing scheme, efficiency benefit sharing scheme or demand management incentive scheme.

With regard to the service target performance incentive scheme a revised proposed scheme covering changes to the exclusion methodology for reliability, revenue at risk and additional changes to the telephone answering parameter are set out in Attachment 0.14 to our regulatory proposal.

1.8 (b) 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 set out in the framework and approach paper, for each variation or departure explain how the variation or departure aligns with the objectives contained in the relevant scheme.

Endeavour Energy's Regulatory proposal does not vary or depart from the application of any component or parameter of the capital efficiency sharing scheme, efficiency benefit sharing scheme or demand management incentive scheme.

With regard to the service target performance incentive scheme a revised proposed scheme covering changes to the exclusion methodology for reliability, revenue at risk and additional changes to the telephone answering parameter are set out in Attachment 0.14 to our regulatory proposal.

1.8 (c) 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 set out in the framework and approach paper, for each variation or departure explain how the proposed variation or departure will impact the operation of the relevant scheme.

Endeavour Energy's Regulatory proposal does not vary or depart from the application of any component or parameter of the capital efficiency sharing scheme, efficiency benefit sharing scheme or demand management incentive scheme.

With regard to the service target performance incentive scheme a revised proposed scheme covering changes to the exclusion methodology for reliability, revenue at risk and additional changes to the telephone answering parameter are set out in Attachment 0.14 to our regulatory proposal.

2. Classification of Services

2.1 (a) Identify each proposed service classification which departs from a service classification set out in the framework and approach paper in the regulatory proposal and explain the reasons for the departure, including why the proposed service classification is more appropriate.

Each proposed service classification in Endeavour Energy's Regulatory proposal does not depart from a service classification set out in the framework and approach paper.

2.1 (b) Identify each proposed service classification which departs from a service classification set out in the framework and approach paper in the regulatory proposal and explain how the treatment of the service will differ under the proposed service classification in comparison to that in the framework and approach paper.

Each proposed service classification in Endeavour Energy's Regulatory proposal does not depart from a service classification set out in the framework and approach paper.

2.2 (a) If the proposed service classifications in the regulatory proposal depart from any of the service classifications set out in the framework and approach paper 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.

The proposed service classifications in Endeavour Energy's Regulatory proposal do not depart from any of the service classifications set out in the framework and approach paper.

2.2 (b) If the proposed service classifications in the regulatory proposal depart from any of the service classifications set out in the framework and approach paper identify and explain where the regulatory templates differ.

The proposed service classifications in Endeavour Energy's Regulatory proposal do not depart from any of the service classifications set out in the framework and approach paper.

3. Control Mechanisms

3.1 (a) For the proposed forecast revenues that Endeavour Energy estimates to recover from providing direct control services over the forthcoming regulatory control period provide formulaic expressions for the basis of control mechanisms for standard control services and for alternative control services.

Formulaic expressions for the basis of the control mechanisms for standard control services and for alternative control services are set out our Compliance Model, Attachment 9.01 to our regulatory proposal.

3.1 (b) For the proposed forecast revenues that Endeavour Energy estimates to recover from providing direct control services over the forthcoming regulatory control period provide a detailed explanation and justification for each component that makes up the formulaic expression.

Detailed explanations and justifications for each component that make up the formulaic expressions are set out at Attachment 9.03 to our regulatory proposal.

3.2 (a) Demonstrate how Endeavour Energy considers the control mechanisms are compliant with the framework and approach paper.

Attachment 9.03 to our regulatory proposal demonstrates how Endeavour Energy considers the control mechanisms are compliant with the framework and approach paper.

3.2 (b) Also demonstrate for standard control services, how Endeavour Energy considers the control mechanisms are also compliant with clause 6.2.6 and part C of Chapter 6 of the NER.

Attachment 9.03 to our regulatory proposal also demonstrates how Endeavour Energy considers the control mechanism for standard control services are also compliant with clause 6.2.6 and part C of Chapter 6 of the NER.

4. Step Changes

4.1 (a) For all step changes in forecast expenditure (including due to changes in regulatory obligations or requirements and those due to changes in Endeavour Energy's own policies and strategies and obligations) provide in Table 2.17.1 and Table 2.17.2 (and if Endeavour Energy owns any dual function assets, Table 2.17.3 and Table 2.17.4) of regulatory template 2.17, the quantum of the Step change Endeavour Energy (i) forecasts to incur in each year of the forthcoming regulatory control period; (ii) if applicable, has incurred, or expects to incur, in the current regulatory control period relative to expenditure previously approved by the AER.

- Refer to tables 2.17.1 and 2.17.2 for the opex and capex step changes.
- Endeavour Energy has a small number of sub-transmission lines and cables and transformers which could be potentially classified as dual function assets providing standard control services. These assets form transmission exit assets supporting Endeavour Energy's distribution network.

The value of these assets are immaterial and are within Endeavour Energy's existing distribution use of system (DUOS) pricing arrangements. The AER has acknowledged that changing the pricing approach to transmission pricing would not have a material impact on distribution prices and would incur administrative costs. Accordingly, the AER has determined that the distribution pricing will continue to apply for Endeavour Energy. Hence tables 2.17.3 and 2.17.4 of regulatory template 2.17 are not applicable.

4.1 (b) For all step changes in forecast expenditure (including due to changes in regulatory obligations or requirements and those due to changes in Endeavour Energy's own policies and strategies and obligations) provide a description of the Step change.

For the forthcoming regulatory period Endeavour Energy has concluded that the retail dis-synergy, vegetation management, investment prioritisation redundancies and the transfer of ANS and meter services from standard control services are opex step changes. A description of the step change is as follows:

- The retail dis-synergy costs are due to the sale of the retail business, which results in the regulated network services being allocated a greater share of the (reduced) residual corporate and overhead costs. As the 2012-13 financial year was the last year in which we provided any retail support services, the 2013-14 financial year is the first year in which these dis-synergy costs are fully crystallised;
- The vegetation management costs are due to observed increases in contract conformance costs consistent with our ongoing focus on the achievement of required program compliance for this critical risk management function. We have experienced additional cost movements in market delivered contracts;
- Investment Prioritisation Redundancies are a reflection of several efficiency initiatives and a return to a more sustainable level of investment in our network creating a step up in our operating expenditure compared to our base year, resulting in a review in our workforce levels; and
- ANS and meter service change transfer from Standard control is due to the AER reclassifying these services as alternative control services in the Framework and Approach Paper. As a result we have removed the cost related to these services from our standard control operating expenditure forecast for the 2014-19 period

Refer to chapter 6 of the SRP for additional information on the opex step changes.

Descriptions of step changes relating to CAPEX are as follows:

- The completion of Springhill Field Service Centre represents the completion of expenditure on establishing a new, expanded Field Service Centre to house our Wollongong-based staff.
- Reassessed renewal needs arise from detailed consideration of network asset condition, resulting in a risk-based decision to defer their replacement for two to three years.
- NSW Licence Condition Changes are those changes in expenditure that arise from the decision by the NSW Government to amend the Design, Reliability and Performance Licence Conditions, effective from 1 July 2014.
- Design / construction standards are those changes in expenditure that arise from a consideration of design and construction standards across the three NSW DNSPs to enable the adoption of the most efficient standards by all three businesses.
- Labour reductions arise as a result of better aligning the workforce skills and capabilities to the program of works to be achieved, resulting in the reductions in staff numbers in some occupational classes.
- Reduction in peak demand relates to reductions in growth capex due to a slowing in the rate of increase in peak demand.
- Greenfield development relates to the increased growth capex required to provide infrastructure to service new development areas.
- Non-material changes represent a large number of differences between the actual and AER-allowed expenditure that arose generally as a result of efficiency improvements.

4.2 (a) Provide an explanation of when the change occurred, or is expected to occur.

For the forthcoming regulatory period for table 2.17.1:

- The retail dis-synergy costs – Commenced 1 March 2011;
- The vegetation management costs – Ongoing;
- Investment Prioritisation Redundancies – Post 30 June 2015; and
- ANS and meter service change transfer – 1 July 2015.

Refer basis of preparation for table 2.17.2

4.2 (b) Provide an explanation of what the driver of the Step change is.

For the forthcoming regulatory period for table 2.17.1:

- The retail dis-synergy costs – Sale of the Business;
- The vegetation management costs – Increased contract conformance and market delivered contract costs;
- Investment Prioritisation Redundancies – Efficiency initiatives; and
- ANS and meter service change transfer – Regulatory Change.

Refer basis of preparation for table 2.17.2

4.2 (c) Provide an explanation of how the driver has changed or will change (for example, revised legislation may lead to a change in legislative obligation or requirement).

Peak Demand

The rate of increase in peak demand experienced by Endeavour Energy's network has declined in recent years. This fact coupled with the capacity that Endeavour Energy has installed in its network during the current regulatory control period to comply with NSW Design, Reliability and Performance Licence Conditions means that capital expenditure to augment the network is low in comparison to recent years. Growth is however occurring in Sydney's North West and South West Growth Centres. While Endeavour Energy is using the flexibility provided by the change to

our Design, Reliability and Performance Licence Conditions to minimise the amount of capacity installed to service this growth, it is forecast that by 2017/18 demand in these areas will be such that significant new infrastructure will be required and a step change in growth capex will result.

Licence Conditions

In August 2005 the NSW Minister for Energy imposed new Design, Reliability and Performance Licence conditions on the three NSW DNSPs. These Licence Conditions imposed, amongst other things, minimum reliability standards and minimum supply security standards. These conditions were amended on 1 December 2007.

The supply security standards detailed in Schedule 1 of the Licence Conditions in general required sufficient capacity to provide N-1 levels of security on the subtransmission and distribution networks. A compliance date of 30 June 2014 was specified in the conditions.

The NSW Minister for Energy has recently advised that these Licence Conditions are to be amended, effective from 1 July 2014 to remove Schedule 1 and hence remove the mandated requirement for N-1 supply security. It should be noted that N-1 supply security is considered to be good practice internationally to ensure that large groups of customers or loads beyond a certain size are not impacted by the failure of a single network element.

4.2 (d) Provide an explanation of whether the Step change is recurrent in nature.

For the forthcoming regulatory period for table 2.17.1:

- The retail dis-synergy costs – Recurrent;
- The vegetation management costs – Recurrent;
- Investment Prioritisation Redundancies – Not recurrent cost is in 2015/16 and 2016/17 only; and
- ANS and meter service change transfer – Recurrent.

Refer basis of preparation for table 2.17.2

4.3 (a) Provide justification for when, and how, the Step change affected, or is expected to affect the relevant opex category.

For the forthcoming regulatory period for table 2.17.1:

- The retail dis-synergy costs – Commenced 1 March 2011 and impacts all opex categories indirectly when applying the CAM;
- The vegetation management costs – Ongoing and impacts the vegetation management opex category directly and indirectly the overheads when applying the CAM;
- Investment Prioritisation Redundancies – Post 30 June 2015 and impacts all opex categories indirectly when applying the CAM; and
- ANS and meter service change transfer – 1 July 2015 and impacts the maintenance opex categories directly and indirectly the overheads when applying the CAM.

Refer to chapter 6 of the SRP for additional information on the opex step changes.

4.3 (b) Provide justification for when, and how, the Step change affected, or is expected to affect the relevant capex category.

In August 2005 the NSW Minister for Energy imposed new Design, Reliability and Performance Licence conditions on the three NSW DNSPs. These Licence Conditions imposed, amongst other

things, minimum reliability standards and minimum supply security standards. These conditions were amended on 1 December 2007.

The supply security standards detailed in Schedule 1 of the Licence Conditions in general required sufficient capacity to provide N-1 levels of security on the subtransmission and distribution networks. A compliance date of 30 June 2014 was specified in the conditions.

Because of several years of underinvestment in its network, Endeavour Energy was not compliant when these Licence Conditions came into effect.

The major increase in investment in capacity that has occurred during the current regulatory control period has been due to the need to “catch up” on previous under investment to achieve compliance. Once compliance has been achieved, investment in capacity can return to more sustainable levels that ensure that capacity is added at approximately the same rate as increases in demand.

The amendment to the Licence Conditions that takes effect from 1 July 2014 that removes the requirement to maintain an N-1 level of security will have only minimal impact on levels of growth expenditure in the forthcoming regulatory control period. Endeavour Energy has effectively attained compliance with the supply security conditions and future expenditure is only necessary to provide additional capacity to meet growth in demand. The change in licence conditions does not mean that Endeavour Energy will operate a network with significantly higher levels of risk than those allowed under the current version of the conditions. The provision of N-1 security is considered to be good network management practice and minimises the risk of large scale outages in the event of a single failure. What is provided for under the amended version is the ability for Endeavour Energy to accept some level of risk to supply, which enables us to retain some flexibility as to when additional capacity is added.

This is particularly relevant to Endeavour Energy with significant expenditure on establishing infrastructure to supply greenfield development. Growth in demand in these developments is uncertain and there is risk of overinvestment if demand does not eventuate at the rate that was originally envisaged. The ability to accept a certain level of risk allows us to establish minimal levels of infrastructure initially and wait to see how demand develops before making the decision to establish a supply with full N-1 security.

4.3 (c) Provide justification for when, and how, the Step change affected, or is expected to affect total opex.

For the forthcoming regulatory period for table 2.17.1:

- The retail dis-synergy costs – Commenced 1 March 2011 and impacts all opex categories indirectly when applying the CAM;
- The vegetation management costs – Ongoing and impacts the vegetation management opex category directly and indirectly the overheads when applying the CAM;
- Investment Prioritisation Redundancies – Post 30 June 2015 and impacts all opex categories indirectly when applying the CAM; and
- ANS and meter service change transfer – 1 July 2015 and impacts the maintenance opex categories directly and indirectly the overheads when applying the CAM.

Refer to chapter 6 of the SRP for additional information on the opex step changes.

4.3 (d) Provide justification for when, and how, the Step change affected, or is expected to affect the total capex.

In August 2005 the NSW Minister for Energy imposed new Design, Reliability and Performance Licence conditions on the three NSW DNSPs. These Licence Conditions imposed, amongst other

things, minimum reliability standards and minimum supply security standards. These conditions were amended on 1 December 2007.

The supply security standards detailed in Schedule 1 of the Licence Conditions in general required sufficient capacity to provide N-1 levels of security on the subtransmission and distribution networks. A compliance date of 30 June 2014 was specified in the conditions.

Because of several years of underinvestment in its network, Endeavour Energy was not compliant when these Licence Conditions came into effect.

The major increase in investment in capacity that has occurred during the current regulatory control period has been due to the need to “catch up” on previous under investment to achieve compliance. Once compliance has been achieved, investment in capacity can return to more sustainable levels that ensure that capacity is added at approximately the same rate as increases in demand.

The amendment to the Licence Conditions that takes effect from 1 July 2014 that removes the requirement to maintain an N-1 level of security will have only minimal impact on levels of growth expenditure in the forthcoming regulatory control period. Endeavour Energy has effectively attained compliance with the supply security conditions and future expenditure is only necessary to provide additional capacity to meet growth in demand. The change in licence conditions does not mean that Endeavour Energy will operate a network with significantly higher levels of risk than those allowed under the current version of the conditions. The provision of N-1 security is considered to be good network management practice and minimises the risk of large scale outages in the event of a single failure. What is provided for under the amended version is the ability for Endeavour Energy to accept some level of risk to supply, which enables us to retain some flexibility as to when additional capacity is added.

This is particularly relevant to Endeavour Energy with significant expenditure on establishing infrastructure to supply greenfield development. Growth in demand in these developments is uncertain and there is risk of overinvestment if demand does not eventuate at the rate that was originally envisaged. The ability to accept a certain level of risk allows us to establish minimal levels of infrastructure initially and wait to see how demand develops before making the decision to establish a supply with full N-1 security.

4.4 (a) Provide the process undertaken by Endeavour Energy to identify and quantify the Step change.

Refer basis of preparation for tables 2.17.1 and 2.17.2.

4.4 (b) Provide cost benefit analysis that demonstrates Endeavour Energy proposes to address the Step change in a prudent and efficient manner, including the timing of the step change and if Endeavour energy considered a 'do nothing' option compared with other options.

Endeavour Energy has only one step change that results in an increase in forecast capital expenditure during the forthcoming regulatory control period. This step change occurs in the growth category of capex and is the result of the need to establish infrastructure to supply greenfield development in Sydney's North West and South West growth sectors. This development is taking place in areas where there is very little if any existing infrastructure.

The plans that we have developed involve making the best use of the existing infrastructure however it is recognised that this only has sufficient capacity to service the short term needs of this development. Endeavour Energy has reviewed the information available from third parties such as the Department of Planning & Infrastructure, local councils and developers to form a view as to the time when the existing capacity will be exhausted and new infrastructure will be required. On the basis of the available information this would appear to be in 2017/18.

A step change increase in growth capex will be required at this time. Endeavour Energy always considers other options such as demand management and other non-network alternatives when considering the need to establish new infrastructure. Because of the greenfield nature of the development and the lack of existing infrastructure, demand management is not considered feasible to manage the increased demand and the establishment of new infrastructure is considered to be the most cost effective way of meeting the increased demand.

Other step changes in the forthcoming regulatory control period are reductions in expenditure relating to efficiency improvements in the development of our capital expenditure program. These changes have generally come about from obtaining a better understanding of the level of risk that the network is exposed to by carrying out or failing to carry out particular projects or programs. The decision to reduce capex leading to these step changes was made on the basis of an assessment of the overall benefit that customers are likely to receive from particular reductions in capex.

4.5 (a) Provide, if the step change is due to a change in regulatory obligation or requirement, relevant variations or exemptions granted to Endeavour Energy during the previous regulatory control period or the current regulatory control period.

A step change in Endeavour Energy's capex arises from changes in the Design, Reliability and Performance Licence conditions imposed on NSW DNSPs that take effect from 1 July 2014. No variations or exemptions to the requirements in these Licence conditions have been granted to Endeavour Energy during the current or previous regulatory control period.

4.5 (b) Provide, if the Step change is due to a change in regulatory obligation or requirement relevant compliance audits Endeavour Energy conducted during the previous regulatory control period or the current regulatory control period.

The requirement in our Licence Conditions to attain a defined level of network security by June 2014 has driven increased levels of growth and compliance capex in the current regulatory control period. The achievement of compliance with requirements in the required time frame enables expenditure in these areas to reduce to more normal levels in the forthcoming regulatory control period, evidenced by a step change reduction in capex in 2014/15. The Licence Conditions required Endeavour Energy to report on non-compliant network elements on an annual basis. Copies of these Licence Compliance reports for 2009/10 to 2012/13 (the latest available) are provided as Attachment 5.09 to our regulatory proposal.

4.6 With reference to specific clauses of the relevant legislative instrument(s), the (i) previous and new regulatory obligations or requirements; and (ii) changed regulatory obligations or requirement that is driving the Step change.

The NSW government is amending the Design, Reliability and Performance Licence Conditions with effect from 1 July 2014. The material amendment that results in a step change in our capex forecast is the removal of Schedule 1 of the licence conditions, that relates to supply security criteria. The current Licence Conditions are provided as Attachment C to this RIN, the new (post-July 2014) conditions are provided at Attachment 5.30 to our regulatory proposal.

5. Capital Expenditure

5.1 (a) Provide justification for Endeavour Energy's total forecast capex, including why the total forecast capex is required for Endeavour Energy to achieve each of the objectives in clause 6.5.7(a) of the NER.

Endeavour Energy's total forecast capex is required to achieve each of the capex objectives. This is explained in the 'Meeting the Rules' section of our regulatory proposal and Attachment 0.03 to our proposal: 'Addressing the capex and opex objectives, criteria and factors'.

The supporting capex attachments to our regulatory proposal also provide justification. In particular, Endeavour Energy's asset management plans including the Strategic Asset Management Plan (Attachment 5.03 to our regulatory proposal), Strategic Asset Renewal Plan (Attachment 5.06 to our regulatory proposal), the Distribution Works Program (Attachment 5.26 to our regulatory proposal), the Reliability Works Program (also Attachment 5.26 to our regulatory proposal) and the Transmission Network Planning Review (Attachment 5.05 to our regulatory proposal) detail how identified network needs are translated into capital expenditure projects and programs.

5.1 (b) Provide justification for Endeavour Energy's total forecast capex, including how Endeavour Energy's total forecast capex reasonably reflects each of the criteria in clause 6.5.7(c) of the NER.

Endeavour Energy's total forecast capex reasonably reflects each of the capex criteria. This is explained in the 'Meeting the Rules' section of our regulatory proposal and Attachment 0.03 to our proposal: 'Addressing the capex and opex objectives, criteria and factors'.

The supporting capex attachments to our regulatory proposal also provide justification. In particular, Endeavour Energy's asset management plans including the Strategic Asset Management Plan (Attachment 5.03), Strategic Asset Renewal Plan (Attachment 5.06), the Distribution Works Program (Attachment 5.26), the Reliability Works Program (also Attachment 5.26) and the Transmission Network Planning Review (Attachment 5.05) detail how identified network needs are translated into capital expenditure projects and programs.

5.1 (c) Provide justification for Endeavour Energy's total forecast capex, including how Endeavour Energy's total forecast capex accounts for the factors in clause 6.5.7(e) of the NER.

Endeavour Energy's total forecast capex accounts for each of the capex factors. This is explained in the 'Meeting the Rules' section of our regulatory proposal and Attachment 0.03 to our proposal: 'Addressing the capex and opex objectives, criteria and factors'.

The supporting capex attachments to our regulatory proposal also provide justification. In particular, Endeavour Energy's asset management plans including the Strategic Asset Management Plan (Attachment 5.03), Strategic Asset Renewal Plan (Attachment 5.06), the Distribution Works Program (Attachment 5.26), the Reliability Works Program (also Attachment 5.26) and the Transmission Network Planning Review (Attachment 5.05) detail how identified network needs are translated into capital expenditure projects and programs.

5.1 (d) Provide justification for Endeavour Energy's total forecast capex, including an explanation of how the plans, policies, procedures and regulatory obligations or

requirements identified in regulatory templates 7.1 and 7.3, and consultants reports, economic analysis and assumptions identified in 1.5 have been incorporated.

Endeavour Energy's total forecast capex is justified by the information included in our regulatory proposal and supporting documents. In particular, Endeavour Energy's asset management plans including the Strategic Asset Management Plan (Attachment 5.03), Strategic Asset Renewal Plan (Attachment 5.06), the Distribution Works Program (Attachment 5.26), the Reliability Works Program (also Attachment 5.26) and the Transmission Network Planning Review (Attachment 5.05) detail how identified network needs are translated into capital expenditure projects and programs.

A significant part of our augmentation capex is as a result of greenfield development in Sydney's North West and South West Growth Centres. This type of development is heavily dependent on factors external to Endeavour Energy. Attachment 5.21 to our regulatory proposal provides details of the external drivers that are considered likely to result in need for Endeavour Energy to establish infrastructure to service these developments during the next regulatory control period.

5.1 (e) Provide justification for Endeavour Energy's total forecast capex, including an explanation of how each response provided to paragraph 5.1 is reflected in any increase or decrease in expenditures or volumes, particularly between the current and forthcoming regulatory control periods, provided in regulatory templates 2.1 to 2.12.

Increases and decreases in volumes and expenditures, particularly between the current and forthcoming regulatory control periods are discussed in our regulatory proposal and supporting documents, in particular the asset management plans detailed in our response to question 5.1 (d) above and Attachment 0.03 to our regulatory proposal and attachments supporting our capital expenditure forecast.

The most significant change discussed in these documents is the reduction in expenditure on augmenting the network to provide capacity to supply growth in peak demand. This is driven by two factors: the general decline in the rate of increase in peak demand that has become apparent over the course of the current regulatory control period; and the fact that Endeavour Energy has invested in significant additional capacity during the course of the current regulatory control period to meet the requirements of its Design, Reliability and Performance Licence conditions. In general, this capacity will be sufficient to meet the forecast demand for the forthcoming regulatory control period and minimal further investment in additional capacity will be required.

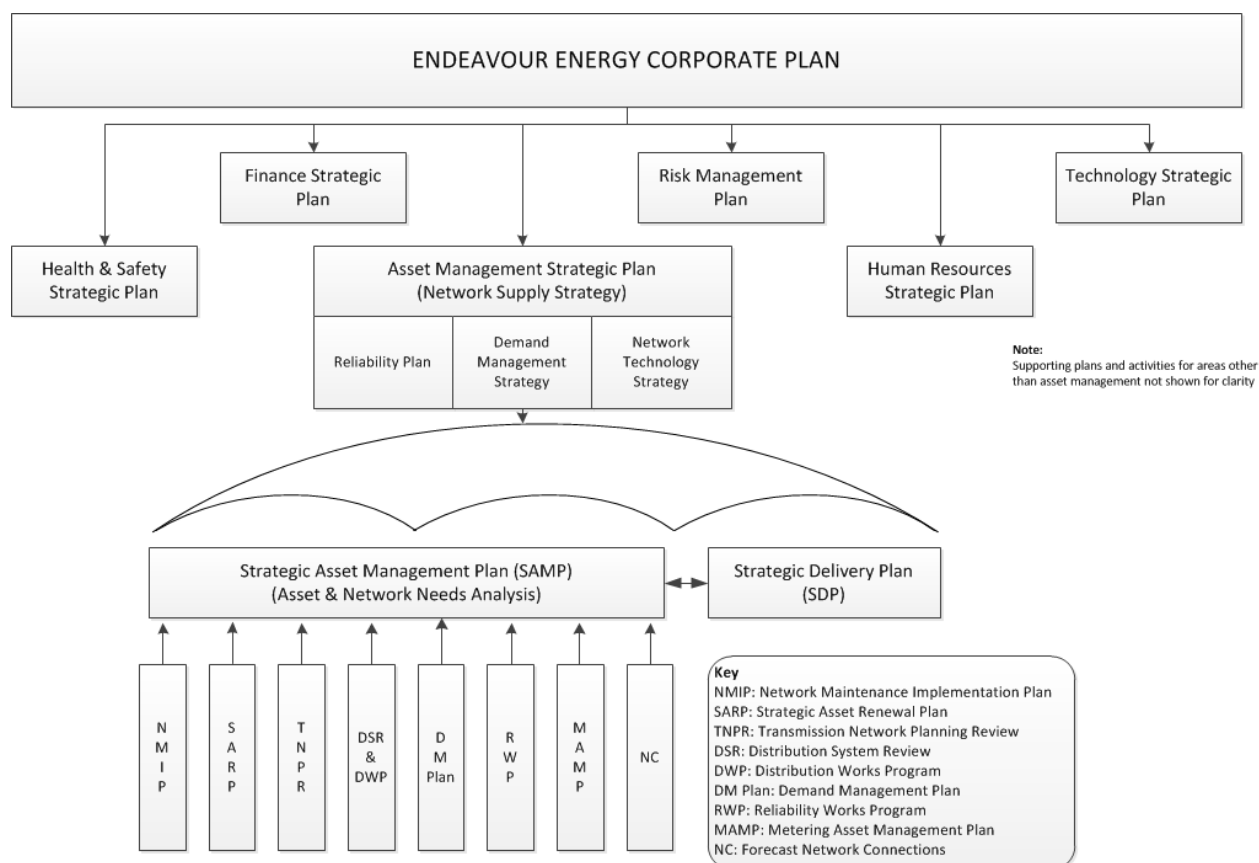
5.2 (a) Provide the model(s) and methodology Endeavour Energy used to develop its total forecast capex, including a description of how Endeavour Energy prepared the forecast capex, including (i) how its preparation differed or related to budgetary, planning and governance processes used in the normal running of Endeavour Energy's business; (ii) the processes for ensuring amounts are free of error and other quality assurance steps; and (iii) if and how Endeavour Energy considered the resulting amounts, when translated into price impacts, were in the long term interest of consumers.

5.2 (b) Provide the model(s) and methodology Endeavour Energy used to develop its total forecast capex, including any source material used (including models, documentation or any other items containing quantitative data).

5.2 (c) Provide the model(s) and methodology Endeavour Energy used to develop its total forecast capex, including all calculations that demonstrate how data from the source

material has been manipulated or transformed to generate data provided in the regulatory templates.

The process for developing capex forecasts is described in Attachment 0.08 to our substantive regulatory proposal and within Chapter 5 of our proposal. Endeavour Energy takes a systematic approach in its development of forecast capex programs and the process followed for the regulatory period forecast is no different to normal budgetary, planning and governance processes. These programs form part of a holistic approach to asset management as summarised in the Endeavour Energy Corporate Plan below:



Future capex programs are contained within the Strategic Asset Management Plan (SAMP – Attachment 5.03 to our regulatory proposal), which identifies future capital (and operating) expenditure needs over a forward ten (10) year period. Individual plans are developed in the key expenditure areas based on asset need. The SAMP uses a risk-based project prioritisation framework to integrate and prioritise these plans into an overall capital and operating expenditure program with appropriate input from relevant stakeholders. The plan is updated on an annual basis and contains proposed costs of all future capex. The capex inputs into SAMP are shown in Table 1 below:

Network Objective	Managed By	Program Description
Servicing growth in demand in Endeavour Energy's network area	Major Projects Program (TNPR) (Attachment 5.05 to our regulatory proposal)	Manages supply security at transmission and zone substation level
	Distribution Works Program (DNSR & DWP) (Attachment 5.26 to our regulatory proposal)	Manages capacity at distribution system level

	Low Voltage Development	Manages capacity at low voltage level
	Customer Connection	Ensures appropriate capacity added to network for new connections
	Demand Management Program (DM Plan) (Attachment 5.34 to our regulatory proposal)	Manages demand reductions to defer capital expenditure on network augmentation projects
Meeting customers' reliability needs	Reliability Works Program (RWP) (Attachment 5.27 to our regulatory proposal)	Manages reliability works through network augmentation/improvements
	Power Quality Program	Tracks quality of supply throughout the network to highlight areas for improvement
Managing the network efficiently and sustainably	Strategic Asset Renewal Plan (SARP) (Attachment 5.06 to our regulatory proposal)	Manages the replacement of assets that have reached the end of their effective life
	Efficiency (Network Technology Strategy – Attachment 5.32 to our regulatory proposal)	Implementation of Technology initiatives and programs for efficiency improvements

In principle, capex forecasts for individual programs are produced by identifying specific network needs and the location/quantity. An appropriate unit rate, normally based on past experience, is then applied to determine an expenditure forecast.

A bottom up approach is taken to producing each of the programs in the capex forecast. There is no one single model that encompasses all capital expenditure forecasts. There are a large number of discrete models which forecast individual programs or components within programs. For renewal driven expenditure there is a validation check on the bottom up forecast, which is performed by carrying out top down analysis using the VDA model which is similar to the Repex model used by the AER.

These streams of capital expenditure are discussed below.

1. Servicing Growth in Demand in Endeavour Energy's Network Area

1.1. Major Projects Program

Growth in demand broadly originates in two basic ways in Endeavour Energy, namely development driven growth and organic growth. The former results from greenfield development such as the North West and South West growth areas, spot loads and infill development (eg urban consolidation), and the latter from a general maturing of demand in existing areas (eg addition of appliances such as air conditioners). These growth patterns are consolidated in Endeavour's 10 year spatial demand forecasts, the process for which involves the assessment of the quantum of each of the future organic and new development driven demands at zone substation levels. Note that the forecast for organic growth is based on the expected increase in air conditioning load. These demands are temperature corrected to 10% PoE and 50% PoE values and consolidated to form the demand forecast, including that for Transmission

Substations and Bulk Supply Points. More detail of the forecasting process is contained in the Basis of Preparation document for RIN templates 5.3 and 5.4. The forecast forms the basis for the network planning process, which is a “zero-based” approach. Up to date computer models of the subtransmission network, including current equipment ratings, are prepared, future loads (50%PoE) are applied at each load point and load flows of these models executed. Supply security standards for the transmission network are defined in Planning Policy 9.2.1 (Attachment 5.13 to our regulatory proposal). These load flows identify those elements of the network that are, or will be, constrained under system normal and single contingency scenarios during the forecast period. The results of this analysis are summarised in the Transmission Network Planning Review (TNPR – Attachment 5.05 to our regulatory proposal) and include preliminary proposals for the rectification, or addressing of any constraints identified. Constraints that are identified will be addressed subject to a risk assessment and cost benefit analysis. Note that no costs are attributed at this stage to proposals identified in the TNPR. Verified constraints that require network investment generate major projects which are individually identified in the SAMP (Attachment 5.03 to our regulatory proposal) with a budget estimate based on past experience with similar constraints.

1.2. Distribution Works Program (DNSR & DWP)

The forecast for Distribution feeder capital expenditure requirements is described in detail in the DWP Attachment 5.26 to our regulatory proposal.

1.3. Low Voltage Development

The low voltage network is often subject to small increases in demand that individually do not impact the network overall. Cumulatively however, this growth in demand overloads the low voltage network and distribution substations, resulting in low voltage and other supply quality issues for customers. This element of the SAMP is intended to address these issues.

The following programs are included in this category;

- Overloaded Distribution sub uprates
- Quality of supply reactive projects
- Quality of supply planned projects
- Low Voltage System Augmentations
- Distribution monitoring and LV feeder monitoring

Capex for this relatively small area is generally determined using historical data. For example, for overloaded substations a forecast of overloaded substations was carried out and unit rates (based on past projects) were applied to generate a capex forecast.

1.4. Customer Connection

Endeavour Energy considers the cost of connecting new customers in three broad categories:

- Industrial and commercial;
- Non-urban; and
- Underground Residential Developments.

The New Connections program is developed annually in each of these areas from a consideration of the forecast growth in customer numbers, as well as information from planning authorities and developers concerning their upcoming land development plans.

1.5. Demand Management Program (DM Plan)

The capex component of DM Programs is limited to the provision of sundry hardware for remote control schemes, requiring the provision of interval meters and remote switches. All other costs are included in the opex budget. As such, the capital requirements in this area are small.

The demand management strategy is focused on the use of non-network alternatives to augmentation of the network where trials of the intended systems or technology have proven them to be cost-effective.

Answers to questions in Section 21 provide further information on Endeavour Energy's Demand Management processes.

1.6 Customers' Reliability Needs - Reliability Works Program

The approach to developing the reliability program is described in detail in the Reliability Plan (Attachment 5.28 to our regulatory proposal) and RWP Attachment (Attachment 5.27 to our regulatory proposal) provide detailed project briefs for the 2014-15 financial year. Projects are developed following detailed feeder investigations.

Forward expenditure over the next regulatory was based on historical expenditure levels which is required to maintain current overall performance levels and comply with the Licence Conditions.

1.7. Power Quality

This section forms a small part of the capex budget and is designed to address "Quality of Supply", which refers to steady state voltage levels as well as electrical disturbances that can affect customer equipment such as voltage sags / swells, voltage fluctuations (flicker), harmonics and three phase imbalance.

In order to obtain the data necessary for power quality management, the Power Quality budget is designed to provide dedicated power quality monitors at zone and transmission substations as well as smart meters and specialised power quality monitors installed at customer installations to collect power quality data.

Further description of the Power Quality capital expenditure is in the SAMP (Attachment 5.03 to our regulatory proposal).

2. Managing the Network Efficiently and Sustainably

2.1. Strategic Asset Renewal Plan (SARP)

Further detail of replacement capital expenditure modelling is included in Section 6.0 and also explained in the SARP Attachment 5.06 to our regulatory proposal.

A guiding principle in the development of forward programs for replacement is the use of age profile data with agreed replacement lives. Current replacement lives are based on a review carried out by consultants Sinclair Knight Mertz in 2010 and further developed as part of the REPEX Benchmarking Review (February 2014).

2.2. Efficiency (Network Technology Strategy)

A description of how capital expenditure forecasts were calculated in relation to Network Technology is contained in the SARP (Attachment 5.06 to our regulatory proposal) and SAMP (Attachment 5.03 to our regulatory proposal).

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

The process for developing capex forecasts is described in Attachment 0.08 to our regulatory proposal. Endeavour Energy has a governance framework in place which results in capex forecasts being reviewed multiple times before final approval. This includes review by line management initially, the Endeavour Energy Investment Governance Committee, the Networks NSW Network Steering and Investment Steering Committees, and eventually the Board.

and

(ii) if and how Endeavour Energy considered the resulting amounts, when translated into price impacts, were in the long term interest of consumers.

In relation to section 5.2 (a) (iii), refer to the SAMP (Attachment 5.03 to our regulatory proposal) Section 2.2 for details of Endeavour's target to limit increases in its share of customers' electricity bills to at or below CPI. In summary, this involves a rigorous approach to the evaluation of the costs and benefits of proposed projects and programs.

(a) any source material used (including models, documentation or any other items containing quantitative data):

Relevant documents that support the capital works strategies for Endeavour Energy are provided with this submission. Endeavour Energy has provided a list of supporting documents that accompany Chapter 5 Capital Expenditure of its Regulatory Proposal.

(b) all calculations that demonstrate how data from the source material has been manipulated or transformed to generate data provided in the regulatory templates.

Details of data manipulation for each of the RIN templates are provided in the Bases of Preparation documents that form part of the regulatory submission. The RIN templates that are relevant to the determination of future network capex are:

- Table 2.2.1 Repex
- Tables 2.3.1/2/3/4 Augex
- Tables 2.4.1/2/3/4/5/6 Augex Models
- Table 2.5.1 Connections

5.3 Identify which items of Endeavour Energy's forecast capex have been:

a) derived directly from competitive tender processes;

No part of the forecast Capex is derived directly from a competitive tender process.

b) based upon competitive tender processes for similar projects;

No part of the forecast Capex is derived directly from competitive tender processes for similar projects. There is an indirect link as typical historical project costs are used to forecast future project expenditure. Typical costs are based past projects which generally have a proportion of costs that are subject to competitive tender process.

c) based upon estimates obtained from contractors or manufacturers;

No part of the forecast Capex is derived directly from estimates obtained from contractors or manufacturers.

d) based upon independent benchmarks;

No part of the forecast Capex is based upon independent benchmarks.

e) based upon actual historical costs for similar projects.

In relation to project estimating, there are several scenarios that need to be considered as follows:

Major Projects (including Major Renewal Projects)

At the initial inception stage of a project, ie after the identification of a network need, normally as part of the TNPR, and the translation of that need into the SAMP, a historical estimate based on past projects of similar content is generally used at that stage. However, when action is taken to begin project implementation this follows the procedure set out in Attachment 5.14 to our regulatory proposal, GAM 0035 Major Project Formulation and Approval. In summary, and assuming that DM initiatives cannot address the network need, a Network Investigation Options (NIO) team is formed to address the possible and most feasible network option to address the constraint. This involves the preparation of a first stage approval that contains a preliminary "bottom up" estimate based on what is a fairly detailed understanding of the project needs for the identified preferred option. These costs are prepared using current prices for major equipment based on existing contracts where these exist.

A "first stage" approval is then obtained that allows detailed design on the preferred option to proceed. This process allows the project estimate to be refined using the most up to date plant prices and to assess and quantify any further project requirements. Once this detailed estimate is produced, a "second stage" approval is sought for the final amount. Note that if the regular annual review of the SAMP occurs during the time span of this development/approval process, then the costs as understood at this stage are included in the updated SAMP. Refer to Attachment 5.14 to our regulatory proposal for major projects formulation and approval process.

Distribution Works

Estimates for all distribution works are based on a unit rate principle for proposed works that are identified within the DWP, including for general HV works, overloaded feeders and those works associated with major projects. This unit rate system comprises a comprehensive list of activities and is updated on an annual basis through consultation with Regional staff as material costs and/or work method practices change. Further detailed estimates are produced post-detailed design in the Regions for final approval of the works.

Renewal Programs

Again, estimates in this area are based on an understanding of unit rates for each specific activity. Once a renewal volume is understood and identified in the SARP, then costs can be determined for the total program using the current unit rates. Similar to the distribution area, the rates are updated on an as needs basis through consultation with Regional staff as material costs and/or work method practices change.

5.3 (f) Identify which items of Endeavour Energy’s forecast capex have been reflective of any amounts for risk, uncertainty or other unspecified contingency factors, and if so, how these amounts were calculated and deemed reasonable.

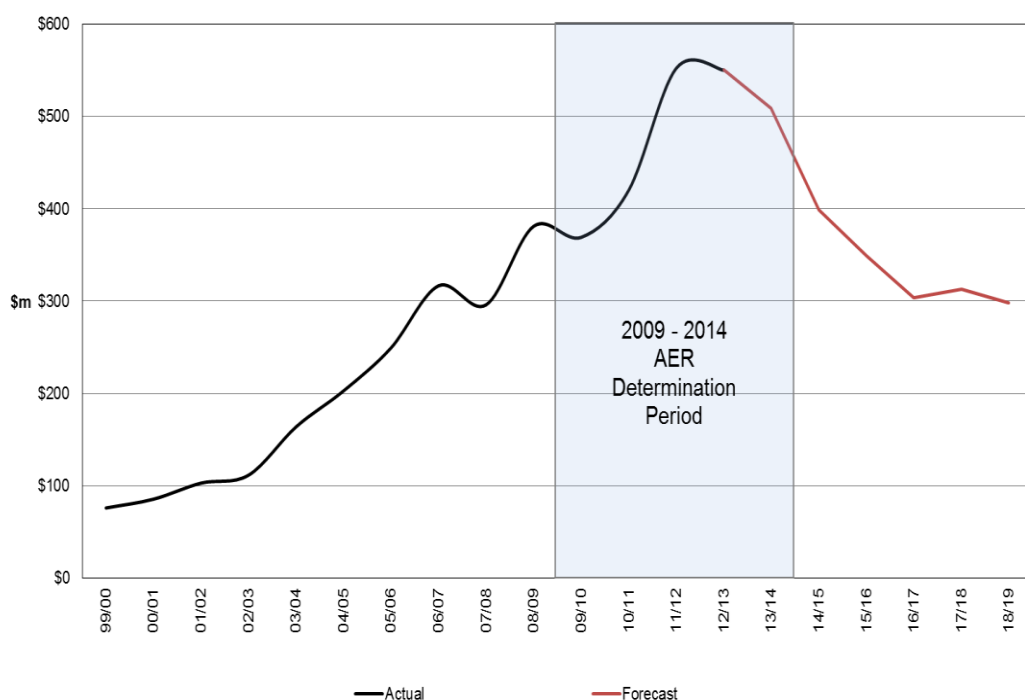
The key area of uncertainty in the capex forecast arises from projects proposed to provide capacity to service greenfield development. A number of projects have been proposed based on information from developers and the Department of Planning. The rationale for these is found in the various greenfield development business cases (Attachment 5.22 to our regulatory proposal).

The expenditure proposed for each of these projects reflects the probability that is assigned to each individual development proceeding. Total expenditure proposed for these projects in total is expected to be sufficient to establish the infrastructure for those developments that do proceed. Projects in the forecast that have already been approved by the Board include contingency amounts that are reflective of the risk associated with delivering the project.

5.4 Provide all documents which were taken into account and relate to the deliverability of forecast capex and explain the proposed deliverability.

Our ‘peak’ investment program in 2009-14

At the beginning of the 2009-14 regulatory period, we were faced with the challenge of delivering a network capital investment program for customers that was around 50% larger in magnitude than any historically delivered program. Of particular note, the required program represented a peak in capital investment volumes for our company, with a return to sustainable longer term capital investment from 2014 onwards as shown below.



Successful delivery in 2009-14

In order to deliver this increased program of work and in recognition of the need to enhance customer value throughout this peak period, we implemented a range of initiatives to improve the efficiency and sustainability of the delivery of our capital program.

These initiatives included:

- Refocusing our program management framework and project management systems, processes and resources as well as the engagement of 'term-based' staff to project manage the implementation of the peak investment program.
- Increasing the use of skilled external resources through a strategy of Peak Resourcing which involved the engagement of external contracted resources for key physical program delivery areas.

Under this Peak Resourcing delivery strategy we used a mix of internal and external resources, resulting in a significant percentage of market-tested and externally sourced investment. Overall around 80% of network capital investment during the 2009-14 was either tested in the market and/or externally sourced.

Moreover, this strategy enabled us to successfully implement the planned scope of work and more effectively deliver peak workloads at a lower than expected cost, without increasing employee numbers to a level that would be unsustainable in the future when investment levels reduce. We have also achieved substantial delivery savings on key major projects and reduced the size of our required capital investment program during the 2009-14 period.

Delivery Strategy for 2014-19

We are in a strong position to deliver the required network investment whilst reducing our capital expenditure during the 2014-19 regulatory period. These reductions will flow from a combination of fewer capital projects (primarily due to lower demand growth), using internal delivery resources and also engagement with the private sector to drive lower unit costs and better targeting of our capital projects to deliver the required customer outcomes.

We have adjusted our delivery strategy for the next period to take account of the reduced delivery program and our focus now is to demonstrate efficiency by employing a blended delivery approach, using a combination of both internal and external resources across all areas of the program. This approach will enable us to achieve efficient, flexible and sustainable customer delivery for future periods.

Equipment and services necessary to deliver our program will continue to be purchased at the best price and the delivery process is planned to make the most efficient use of available internal and external resources.

The pursuit of delivery efficiencies in our capital expenditure program has been carried out in consultation with our workforce. This approach ensures all relevant knowledge on an issue from across the Company is leveraged to obtain the best solution to a problem. The collaborative approach is also in line with our determination to foster a workplace culture which delivers high standards of performance to customers.

A fundamental part of ensuring delivery efficiency has been our introduction of a work process reform to streamline program planning and management. Part of this improved approach included developing a SAMP Delivery Plan (SDP), which is included as an attachment. The SDP confirms the deliverability of the Network capital program. It clarifies the scope of the program and network

delivery priorities, identifies what levels of resources are needed to deliver the capital program and defines the strategy to use a combination of contractors and internal delivery resources.

With this strategy we will be able to continue to deliver the required network investment in a timely and cost effective manner that best meets the needs of our customers.

Refer to Attachment 5.04 of our proposal for our SAMP Delivery Plan.

Capex categories

5.5 (a) Describe each capex category and expenditures comprising these categories identified in the regulatory templates including key drivers for expenditure.

The capex categories identified in the regulatory templates are, by definition

- Augmentation Capital Expenditure
- Connections Capital Expenditure
- Replacement Capital Expenditure

These categories are described in the SAMP (Attachment 5.03 to our regulatory proposal). The Augmentation based categories relate to Major Projects (PR), Distribution Works Program, LV Development in the SAMP. Connections capital expenditure is described in the Customer Connections expenditure in the SAMP. It should be noted that a significant number of Major Projects (PR) are driven by new network connections in greenfield development areas. Replacement capital expenditure is described in summary in the SAMP under the Strategic Asset Renewal Plan section.

5.5 (b) Describe each capex category and expenditures comprising these categories identified in the regulatory templates including an explanation of how expenditure is distinguished between demand driven and non-demand driven augmentation capital expenditure, connections capital expenditure and augmentation capital expenditure, replacement capital expenditure driven by condition and asset replacements driven by other drivers (e.g. the need for demand or non-demand driven augmentation capital expenditure) and any other capex category or opex category where Endeavour Energy considers that there is reasonable scope for ambiguity in categorisation.

(i) demand driven and non-demand driven augmentation capital expenditure

All augmentation works in the templates 2.3 and 2.4 are fundamentally demand driven. Renewal expenditures are captured in templates 2.2. Endeavour Energy assigns a primary driver to each major project and program in its capital expenditure forecast. This distinguishes between demand driven and non-demand driven augmentation capital expenditure.

(ii) connections expenditure and augmentation capital expenditure

In the relevant templates, (eg Table 2.4.6), expenditures are divided into “customer initiated” and “NSP initiated”. While both of these categories are demand driven, the former can be directly associated with specific greenfield residential or industrial development, while the latter is as a result of a need to reinforce the higher tiers of the network due to organic load growth. Endeavour Energy assigns a primary driver to each major project and program in its capital expenditure forecast. This distinguishes between “Network Connection” driven expenditure versus existing capacity constraints that have arisen over time in a gradual manner.

(iii) replacement capital expenditure driven by condition and asset replacements driven by other drivers (e.g. the need for demand or non-demand driven augmentation capital expenditure)

Endeavour Energy adopts a range of approaches for identifying assets that are candidates for renewal, ranging from simple inspection and condition-based maintenance regimes through to detailed technical analysis of key asset indicators.

Using these approaches outlined above, short-term renewal programs are established based on available data supplemented with expert knowledge of the imminent end-of-life of the assets in question. These short-term programs are integrated into longer term renewal programs to provide accurate expenditure projections and enable the efficient integration of renewal, growth-driven and other asset management activities. Replacement capex is generally non-demand driven. However, a coordinated approach is taken whereby when a replacement need is identified, any augmentation needs are taken into account, and if these augmentation needs are considered to be the dominant driver for the augmentation, then the project will become a capacity driven project.

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

Endeavour Energy has no categories when the categorisation is considered ambiguous.

6. Replacement Capital Expenditure Modelling

6.1 (a)(i) In relation to information provided in regulatory templates 2.2 and 5.2 and with respect to the AER's repex model, provide in relation to individual asset categories set out in the regulatory templates, provide in a separate document a description of the asset category, including the assets included and any boundary issues (i.e. with other asset categories), an explanation of how these matters have been accounted for in determining quantities in the age profile, an explanation of the main drivers for replacement (e.g. condition, etc.) and 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.

The Strategic Asset Renewal Plan (SARP) (Attachment 5.06 of our regulatory proposal) contains an appendix entitled "Replacement Capital Expenditure Modelling". Section 5 of the Appendix provides Endeavour Energy's response to this requirement.

6.1 (a)(ii) In relation to information provided in regulatory templates 2.2 and 5.2 and with respect to the AER's repex model, provide, in relation to individual asset categories set out in the regulatory templates, provide in a separate document an estimate of the proportion of assets replaced for each year of the current regulatory control period, due to aging of existing assets (e.g. condition, obsolesce, etc.) that should be largely captured by this form of replacement modelling, replacements due to other factors (and a description of those factors), additional assets due to the augmentation, extension, development of the network, additional assets due to other factors (and a description of those factors).

The Strategic Asset Renewal Plan (SARP) (Attachment 5.06 of our substantive regulatory Proposal) contains an appendix entitled "Replacement Capital Expenditure Modelling". Section 5 of the Appendix provides Endeavour Energy's response to this requirement.

6.1 (b) In relation to information provided in regulatory templates 2.2 and 5.2 and with respect to the AER's repex model, provide justification for the replacement life statistics provided (the mean and standard deviation), including the methodology, data sources and assumptions used to derive the statistics, the relationship to historical replacement lives for that asset category, Endeavour Energy's views on the most appropriate probability distribution to simulate the replacement needs of that asset category, including matters

such as: the appropriateness of the normal distribution or another distribution (e.g. the Weibull distribution), the typical age when the “wear out” phase becomes evident, the “skewness” of the distribution and the process applied to verify that the parameters are a reasonable estimate of the life for the asset category

The Strategic Asset Renewal Plan (SARP) (Attachment 5.06 of our substantive regulatory Proposal) contains an appendix entitled “Replacement Capital Expenditure Modelling”. Section 5 of the Appendix provides Endeavour Energy’s response to this requirement.

6.1 (c) In relation to information provided in regulatory templates 2.2 and 5.2 and with respect to the AER's repex model, provide the derivation of replacement unit costs and asset lives, including any internal documentation or analysis or independent benchmarking, that justifies or supports its cost data. This must cover: the methodology, data sources and assumptions used to derive the cost data, the possibility of double-counting costs in the estimate, and the process applied to ensure this is appropriately accounted for, the variability in the unit costs between individual asset replacements, and the main drivers of the variability, the relationship of the unit cost, and its derivation, to historical replacement costs for that asset category (this should clearly differentiate and quantify any assumed cost difference due to labour/material price changes and other factors), the process applied to verify that the parameter is a reasonable estimate of the unit cost for the asset category and identify and provide information or documentation to justify and support any responses to 6.1(c) above.

The Strategic Asset Renewal Plan (SARP) (Attachment 5.06 of our substantive regulatory Proposal) contains an appendix entitled “Replacement Capital Expenditure Modelling”. Section 5 of the Appendix provides Endeavour Energy’s response to this requirement.

6.1 (d) In relation to information provided in regulatory templates 2.2 and 5.2 and with respect to the AER's repex model provide for the previous, current and forthcoming regulatory control periods, explain the drivers or factors that have affected changing network replacement expenditure requirements. Identify and quantify the relative effect of individual matters within the following categories: rules, codes, license conditions, statutory requirements, internal planning and asset management approaches, 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, 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 (the external factors to be discussed here do not relate to changing obligations which are covered in paragraph 4., technology/solutions to address needs, covering network and non-network, any other significant matters. The information provided above should at least distinguish between the asset categories defined above. Identify and provide information or documentation to justify and support any responses to (d) above.

The Strategic Asset Renewal Plan (SARP) (Attachment 5.06 of our substantive regulatory Proposal) contains an appendix entitled “Replacement Capital Expenditure Modelling”. Section 5 of the Appendix provides Endeavour Energy’s response to this requirement.

7. Augmentation Capital Expenditure Modelling

7.1 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.

All instructions in this RIN have been read in conjunction with the AER's augex guidance document obtained from the AER's website.

7.2 (a)(i) In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model, provide separately for sub-transmission lines, sub-transmission and zone substations, HV feeders and distribution substations, Endeavour Energy must explain how it prepared the maximum demand (weather corrected at 50 per cent probability of exceedance; see Schedule 2 for further guidance) data provided in the asset status tables (tables 2.4.1 to 2.4.4), including where relevant: how this value relates to the maximum demand that would be used for normal planning purposes, whether it is based upon a measured value, and if so, where the measurement point is and how abnormal operating conditions are allowed for, 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 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.

In relation to 7.2(a)(i) Feeder maximum demand data was obtained from the Network Load History (NLH) database, which directly accesses Endeavour Energy's SCADA system.. There is a standard methodology employed to convert this data to 50% PoE, and this is further discussed in the forecasting sections of this report (Section 8). For subtransmission and distribution feeders, the conversion to a 50% PoE demand utilised the ratio of 50% PoE total and measured peak at the associated Transmission or Zone Substation. Load data for distribution substations is obtained from annually read Maximum Demand Indicators (where fitted) on distribution substations.

In relation to 7.2(a)(i)(A)-(D) see the table over the page.

Reference Table	(A)	(B)	(C)	(D)
Table 2.4.1 (Subtransmission feeders)	Load flow models for analysis are based on 50% loads and feeder loads would thus be 50% PoE.	Measured at the relevant circuit breaker. Actual values are compared against load flow values in the TNPR process to help identify spurious results.	Based on actual. In a small number of cases in parts of the network (eg lines in the Mt Piper/Ilford Hall/Kandos area), maximum demand data on lines is not always available and data sourced from the Transmission Network Planning Review (TNPR) reports in the relevant years has been used. This data is based on load flow data and is considered to be representative of real loads.	The relationship of the values provided to raw values depend on the temperature correction applied eg for a cool summer, the raw loads will be adjusted up and for a hot summer adjusted down. The relationship between raw load and the values that reflect a 10 per cent probability of exceedance year would result in values that are generally greater than the 50% values depending on the relative temperature severity of the season.
Table 2.4.2 (Distribution feeders)	The measured maximum demand is used (after filtering of potential abnormal results) as this gives a true representation of the loads that the feeders are expected to encounter in a true operational sense.	Measured at the relevant circuit breaker. Abnormal loads are filtered by a calculation that compares observed maximums on all feeders to ensure that no “outlying” result is included in the feeder maximum loads.	Based on actual.	See above
Table 2.4.3 (Sub-transmission and zone substations)	Load flow models for analysis are based on 50% PoE loads.	Measured at the relevant circuit breaker(s). Substation data is generally meter quality data and is very reliable; however, readings are	Based on actual.	See above

		compared against previous years and against SCADA data or circuit breaker summation data where there is a suspected discrepancy.		
Table 2.4.4 (Distribution substations)	The MDI reading is used directly for planning purposes. Peak loads are verified by local temperature and data monitoring before proceeding with augmentation.	Demand indicators fitted on ~80% of substations. Subs with no MDI are recorded at nameplate rating.	Based on actual	Actual values only provided.

7.2 (a)(ii) In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model, provide separately for sub-transmission lines, sub-transmission and zone substations, HV feeders and distribution substations, Endeavour Energy must explain how it determined the rating data provided in the asset status tables (tables 2.4.1 to 2.4.4) including where relevant: the basis of the calculation of the ratings in that segment, including asset data measured and assumptions made and the relationship of these ratings with Endeavour Energy's approach to operating and planning the network. For example, if alternative ratings are used to determine the augmentation time, these should be defined and explained.

Methodology for tables 2.4.1 and 2.4.4 is described in Basis of Preparation documentation.

Line, cable and transformer ratings were obtained from Endeavour Energy's Network Characteristics Database (current as of 30 June 2013). The basis of ratings is presently as follows:

- Overhead lines – Mains Design Instruction 42, which in turn refers to ESAA publication D(b)5:1988 (Current Rating of Bare Overhead Line Conductors) as the design basis.
- Underground cables (subtransmission) - Mains Design Instruction 46, which uses IEC 60287 as the design basis.
- Underground cables (distribution) - Mains Design Instruction No 11 (Underground distribution cables – continuous current ratings) which uses IEC 60287 as the design basis.
- Transformer ratings are presently based on Australian Standard AS2374.7 (recently updated to AS60076.7).

The ratings stated in the tables are the ones used in augmentation planning. In situations where only the normal cyclic rating of a line is recorded in the database, the emergency rating of that particular line is assumed equal to the normal cyclic rating. Where the normal cyclic rating of a transformer is currently available, this is assumed to be equal to the emergency rating of that particular unit.

7.2 (a)(iii) In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model, provide separately for sub-transmission lines, sub-transmission and zone substations, HV feeders and distribution substations, Endeavour Energy must explain how it how it determined the growth rate data provided in the asset status tables (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 Endeavour Energy.

In all cases, the average per annum load growth at each location over the period 2012/13 to 2018/19 was evaluated directly from the Endeavour Energy 2014/23 published summer forecast, with a simple averaging of the demand growth over the relevant period being calculated. In carrying out this calculation, summer load data has been used as this generally represents the most onerous condition on plant.

7.2 (b)(i) In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model, provide in relation to the capex-capacity table (table 2.4.6),

Endeavour Energy must explain 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.

The costs included in Table 2.4.6 include all project costs, but are exclusive of organisational overheads. However, there is a proportion of non-field and management costs included and this varies depending on project type and size. Typically for subtransmission brownfield, greenfield and minor projects, the non-field and management costs amount to approximately 3-4%, 2-3% and 1% of the total project cost respectively. For distribution projects, these costs range from 1-3% of total project cost.

7.2 (b)(ii) In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model, provide in relation to the capex-capacity table (table 2.4.6), Endeavour Energy must explain how it determined and allocated actual capex and capacity to each of the segment groups covering: the process used, including assumptions, to estimate and allocate expenditure where this has been required, the relationship of internal financial and/or project recording categories to the segment groups and process used.

Project costs were obtained for both subtransmission and zone substation works and distribution feeder works from financial data associated with the list of relevant projects that were completed (or are to be completed) within the requested time frames.

For subtransmission and zone substation works, capacities added were obtained from project related information such as Network Investment Options Reports, Project Definitions, Transmission line designs and Post Commissioning Review Reports. In the case where individual projects are readily visible, that is for major projects and distribution feeder works, including those works associated with major projects, these projects were individually categorised into "NSP initiated" or "customer initiated" and the relevant costs and capacities entered into Table 2.4.6.

The categorisation into "urban", "short rural" and "long rural" was also carried out on a project by project basis for major subtransmission and zone substation projects. In the case of distribution feeders, the ratio of customer/NSP initiated works was determined by the ratio of works carried out in association with new customer associated zone substation works and the annual Distribution Works Program works.

For the distribution transformer (including downstream LV network) category, the customer initiation proportion was provided using customer connection data that indicated a proportion of 90/10 customer/NSP ratio in this class.

The urban/short rural/long rural split was determined for high voltage feeder works by assuming a ratio split equal to the ratio of urban/short rural/long rural feeders within Endeavour Energy. The urban/short rural/long rural split for distribution transformers (including downstream LV network) was determined by assessing the proportion of transformers (from a capacity perspective) that were installed on either urban or short rural feeders.

Note that high voltage distribution feeder works include those works associated with the provision of supply capacity to allow additional connections to the network.

Existing financial systems do not directly map to the suggested segment groups. Instead, financial data is apportioned to organisation units (cost centres) that in some cases map directly to segment groups or alternatively can be aggregated to allow the appropriate gathering of costs. An example would be for the zone substations segment, costs from such org units as Protection, SCADA and communications and HV Test sections would need to be aggregated for each specific project.

7.2 (b)(iii) In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model, provide in relation to the capex-capacity table (table 2.4.6), Endeavour Energy must explain how it determined and allocated estimated/forecast capex and capacity to each of the segment groups covering: the relationship of this process to the current project and program plans, and any other higher-level analysis and assumptions applied.

Allocations to the Subtransmission Lines, Subtransmission Substations and Zone Substations segments were determined for Table 2.4.6 for the years 2006/07 through to 2013/14 based on the project cost analysis and entries contained in Tables 2.3.1 and 2.3.2. The estimates for the remainder of the 2013/14 year were provided by Finance and incorporated into the results. The delineation between customer and NSP initiated augmentation was determined on an individual project by project basis.

Future expenditures for these segments were obtained again from Tables 2.3.1 and 2.3.2, which are based on forward plans as set out in the SAMP. For the high voltage feeder segments, expenditure was based on actual costs for the years 2006/07 through to 2013/14 gathered from Ellipse financial data and separated into customer/NSP ratio using the average ratio of works carried out over the same period.

The Urban/Short Rural ratio was also calculated using the average ratio for this measure for projects spread over a typical six year period. For distribution substations (and downstream LV lines), financial data was obtained from the Ellipse system as explained in the Basis of Preparation for Table 2.4.6. The splits into Urban and Short Rural and customer/NSP initiated are also contained in the same Basis of Preparation. No data was available for the distribution substations associated with customer connections.

In summary all data presented in Table 2.4.6 is in accordance with corporate financial data and future network expansion plans as contained within the SAMP.

No other higher level assumptions or analysis has been made.

7.2 (c) In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model, provide unmodelled augmentation capex – Describe the types of projects and programs Endeavour Energy has allocated to the unmodelled augmentation categories in table 2.4.6 covering: the proportion of unmodelled augmentation capex due to this project or program type, the primary drivers of this capex, and whether in Endeavour Energy's view, there is any secondary relationship to maximum demand and/or utilisation, and whether the outcome of such a project or program, whether intended or not, should be an increase in the capability of the network to supply customer demand at

similar service levels, or the improvement in service levels for a similar customer demand level.

Endeavour has considered that the upgrading of HV conductors for fault level purposes be categorised as unmodelled augmentation given that it is an issue that is not directly driven by capacity needs, but rather a secondary outcome of capacity provision.

Table 2.4.6 indicates that unmodelled augmentation amounts to approximately 10% of the total HV feeder costs measured over an 8 year period.

The primary driver is the rise in system fault level as capacity projects are progressively brought on line. This ensures that no damage to the line will occur as a result of the passage of fault current. There is no relationship to maximum demand.

It can be seen that there is an incidental increase in capacity of a line augmented for fault level reasons. However, there is no guarantee that this capacity will ever be required in the location provided. If the line was subsequently used to supply additional demand, then this would be an incidental benefit.

7.2 (d)(i) In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model, provide network segments separately for each network segment that Endeavour Energy defined in the model segment data table (2.4.5). Describe the segment, including: the boundary with other connecting network segments, and the main reasoning for the individual segment (e.g. as opposed to forming a more aggregate segment).

Endeavour has defined 37 network segment elements in Table 2.4.5. These are divided into 11 segment groups, categorised as follows:

Network segment IDs	Network segment type	AER segment group
1 - 6	Lines 132kV/66kV/33kV summer or winter peaking	1
7 - 13	Transmission Substations 1, 2, 3, 4 or 8 transformers, summer or winter peaking	2
14 - 19	Zone Substation 1, 2 or 3 transformers summer or winter peaking	3
20 - 21	HV Line Urban Summer or Winter	5
22 - 23	Short rural Summer or Winter	6
24 - 25	Long rural Summer or Winter	7
26 - 29	Urban Pad subs <=500kVA, >500kVA Urban Pole subs <=63kVA, <=400kVA	9
30 - 33	Short Rural Pad subs <=500kVA, >500kVA: Short Rural Pole subs <=63kVA: <=400kVA	10
34 - 37	Long Rural Pad subs <= 500kVA,	11

	>500kVA Long Rural Pole subs <=63kVA, <=400kVA	
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The full rationale behind these is contained in the Basis of Preparation for 2.4.5. A short version of the segment descriptions is included below.

(i) Describe the network segment, including:

(A) the boundary with other connecting network segments;

Boundaries are as defined in the table above and as defined by network connectivity, ie subtransmission lines connect to zone substations, zones substations to HV feeders etc.

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

Segment Group 1 -. The \$/MVA vary between the voltages and the ratings of the lines differ between summer and winter.

Segment Group 2 - The capacity factor varies based on the number of transformers installed.

Segment Group 3 - The capacity factor varies based on the number of transformers installed.

Segment Groups 5, 6 and 7 - The \$/MVA vary between summer and winter.

Segment Groups 9, 10 and 11 - The \$/MVA and capacity factor changes depending on the size of the substations.

7.2 (d)(ii) In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model, provide utilisation threshold separately for each network segment that Endeavour Energy defined in the model segment data table (2.4.5). Explain the utilisation threshold statistics provided (i.e. the mean and standard deviation) including: the methodology, data sources and assumptions used to derive the parameters, the relationship to internal or external planning criteria that define when an augmentation is required, the relationship to actual historical utilisation at the time that augmentations occurred for that asset category, Endeavour Energy's views on the most appropriate probability distribution to simulate the augmentation needs of that network segment, and the process applied to verify that the parameters are a reasonable estimate of utilisation limit for the network segment.

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

Refer to Basis of Preparation 2.4.5.

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

The calculated thresholds are generally higher by a small margin than those in existing supply security standards.

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

Projects have been formulated on the forecast demand data available at the time of business case preparation. When augmentations are carried out, often at some date remote from the time

of project issue, forecast loads may not have eventuated, or seasonal issues may be having a significant impact on demand. It is therefore difficult to link past forecasts with current demands.

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

It is considered that there is no strong reason to depart from the normal distribution as proposed.

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

Parameters were compared to the thresholds for actual projects and while the existing licence condition standards are generally slightly less onerous, there is a reasonable degree of agreement.

7.2 (d)(iii) In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model, provide augmentation unit cost and capacity factor separately for each network segment that Endeavour Energy defined in the model segment data table (2.4.5). Explain the augmentation unit cost and capacity factor provided, including: the methodology, data sources and assumptions used to derive the parameters, the relationship of the parameters to actual historical augmentation projects, including the capacity added through those projects and the cost of those projects, 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 the process applied to verify that the parameters are a reasonable estimate for the network segment.

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

Segment Group 1 – The unit costs for transmission lines have been determined by analysing a sample of past major projects which had line works included in them (irrespective of if they had sub transmission feeder constraints or not). The capacity factor for transmission lines was determined by analysing only projects which addressed capacity constrained sub transmission feeders. The source of information was the project definitions created at the time of project initiation and the project cost estimates at the time of project initiation. Unit costs were obtained by dividing the total estimated project costs by the capacity added.

Segment Group 2 – The unit costs for sub transmission substations have been determined by analysing a sample of past major projects which had the augmentation of a sub transmission substation included in them (irrespective of if they had sub transmission substation constraints or not). The capacity factor for sub transmission stations was determined by analysing only projects which addressed capacity constrained sub transmission stations. The source of information was the project definitions created at the time of project initiation and the project cost estimates at the time of project initiation.

Segment Group 3 – The unit costs for zone substations have been determined by analysing a sample of past major projects which had the augmentation of a zone substation works included in them (irrespective of if they had zone substation capacity constraints or not). The capacity factor for zone substations was determined by analysing only projects which addressed capacity

constrained zone substations. The source of information was the project definitions created at the time of project initiation and the project cost estimates at the time of project initiation.

Segment Groups 5, 6 and 7 – The unit costs and capacity factors for distribution lines was determined by analysing high voltage distribution feeder works items created in the last four years.

For each category of feeders the number of projects that created a new feeder (i.e. connection to a zone substation circuit breaker) was identified. From this, the capacity added was calculated by multiplying the number of feeders added by the standard capacity of a feeder (300A). From the project description the number of overloaded feeders it was addressing (at the zone substation circuit breaker) was also noted. The capacity factor was obtained by dividing the number of new feeders created by the number of overloaded feeders addressed.

The costs for all other projects during this period (excluding fault level exceeded items), e.g. augment overloaded conductor, establish cross feeder tie etc., and the costs for projects that created new feeders were summated to give a total cost for all projects. The \$/MVA was then calculated by dividing these summated costs by the capacity added.

Segment Groups 9, 10 and 11 - The unit costs for distribution substations have been obtained from actual costs from sample projects. The capacity factor is calculated by the change in size of transformers for the categories.

The unit costs used for the various categories compare relatively to the Optimised Depreciated Replacement Costs Valuation of the Endeavour Energy network completed in 2010.

More details of these issues are presented in Basis of Preparation 2.4.5.

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

Refer to (A) above, which utilises historical activities.

(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);

Segments have been chosen to avoid double counting of capacities added. Methodology of how capacity was allocated to various segments from projects is described in the Basis of Preparation documents for Table 2.4.5. The data will be audited independently as part of the quality assurance process for the RIN tables.

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

The parameters were calculated from large samples of historical projects across different levels of the network. As such the parameters are considered reasonable estimates for each network segment. The data will be audited independently as part of the quality assurance process for the RIN tables.

7.2 (e) In relation to information provided in regulatory template 2.4 and with respect to the AER's augex model – Explain the significant factors Endeavour Energy considers may

result in different augmentation requirements between itself and other NEM DNSPs, faced with similar asset utilisation and maximum demand growth. Clearly differentiate between those factors that may result in differences between: Endeavour Energy and other DNSPs in the NEM. In discussing these factors, the explanation should clearly indicate those factors that may impact: the maximum achievable utilisation of assets for Endeavour Energy and the likely augmentation project and/or cost. For each significant factor discussed, Endeavour Energy must indicate relevant model segments and estimate the impact these factors will have on its augmentation levels and associated capex compared to other DNSPs.

i. the maximum achievable utilisation of assets for Endeavour Energy;

There are three main factors which differentiate Endeavour Energy:

- For NSW DNSPs, mandated supply security standards in the Licence Conditions which were previously in force created a step change in investment over the last regulatory period. Significant capacity was installed over the last 5 years, and as investment in network infrastructure is lumpy the current utilisation is potentially lower than other urban DNSPs in the NEM as result.
- Endeavour Energy is potentially unique in the NEM with the amount of greenfield development proposed in its franchise area. The NSW State Government has been and continues to release large areas of rural land for urban residential and commercial development to increase the supply of housing in Sydney. The North West and South West Growth Centres of Sydney combined will provide an additional 180,000 new residential dwellings and associated non-residential load (schools, rail, shopping centres, employment lands, water infrastructure). As such although utilisation and demand growth may be low in the existing network, greenfield development areas will still require major network investment due to geographic separation from existing network infrastructure.
- Western Sydney has a different climate to areas closer to Sydney CBD, significantly higher temperatures are often experienced on hot days in Western Sydney. Endeavour may have some conditions that need to be taken into account in the determination of equipment ratings. This is as a result of high levels of residential demand that has high air conditioning penetration and a resulting relatively flat load profile over an extended period. Where these load profiles exist, this has the potential to particularly affect transformer ratings (ie Segments 2 and 3) adversely.

ii. the likely augmentation project and/or cost.

Endeavour Energy's project costs would be similar to those in other predominately urbanised DNSPs.

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

- For the first main factor in relation to investment from the previous regulatory period this has reduced the need for investment in the next 5 years in established suburbs for Segments 1,2,3 and 5 compared with DNSPs outside of NSW.
- For the second factor, in relation to greenfield development, this requires additional investment in Segments 1, 3, 5 and 9 compared with other DNSPs despite lower utilisation overall in the network and low demand growth in the existing network. This is the most significant factor in terms of impact on the forward capital expenditure requirements. The majority of major project growth expenditure proposed in the next regulatory period is related to greenfield development.
- For the third factor on climate, this is inherent in formulation of forward capex forecasts. It places upward pressure on network investment in relation to expenditure in Segments 1,2,3,5 and 9 compared with other DNSPs without similar climatic conditions.

8. Demand and Customer Number Forecasts

8.1(a) Provide and describe the methodology used to prepare the following forecasts - maximum demand.

Historical peak demands for each season are corrected to the respective reference temperatures. The temperature correction is based on a second-order polynomial fit to the weekday daily demands and the corresponding maximum temperatures at Nowra for the South Coast or at Richmond for the remaining areas in summer, and daily 6 pm temperatures at Richmond for all Endeavour Energy areas in winter.

Peak demand forecast accounts for the total growth from the existing customers as well as the new customers. The forecasting process can be divided into two major steps. The first step is to estimate the organic growth at the zone substation which specifies the internal growth from its existing customers likely to be experienced over the forecast period. For summer, it was calculated by the known current and projected penetration rates of air conditioners and the percentage of residential peak load at the zone substation. This organic growth at the zone substation is used to establish the base level of the 10-year forecast. For winter, the organic growth at zone substations is assumed to be flat with zero growth.

The second step of the forecast process involves incorporating the planner's inputs to the base level forecast. The inputs include new developments planned to occur (lot releases), new load increases expected from customer applications (spot loads) and also information regarding the transfer of load from one zone substation to another (load transfers). The final forecast at a zone substation is derived from the base level forecast after adjustment for planned load transfers, spot loads, land releases and re-development in the zone substation.

The expected demand growth included in the final forecasts for all zone substations is validated by the Network Planners. The Network Planners' local knowledge is vital in determining load transfer, embedded generation, proposed spot-loads and predicted lot release information. This feedback also provides an audit trail for quality purposes.

Forecasts at transmission substations and bulk supply points are calculated by the corresponding historical diversity factors. The zone substation forecasts are summated to obtain the undiversified totals and then multiplied by the calculated diversity factor for that transmission substations or bulk supply point.

8.1(b) Provide and describe the methodology used to prepare the following forecasts - number of new connections.

Endeavour Energy considers the number of new connections to be the difference in customer numbers in each year.

Endeavour Energy's customer number forecasts are produced using the following methodology and assumptions:

- Short-term Domestic customer numbers for the months remaining in the current financial year (FY14) and next financial year (FY15) are forecast using historical trends. Long-term forecasts for FY16 to FY19 are produced using a projection of household number growth for the Endeavour Energy network area. Household growth rate projections are sourced from a third-party macroeconomic forecaster, the National Institute of Economic and Industry Research (NIEIR; December 2013);

- Short-term Commercial and Industrial customer numbers take account of recent monthly movements. Long-term forecasts increase in line with the forecast GSP growth rate as sourced from NIEIR (December 2013). The exception to this is large, site-specific industrial customers and non-metered commercial customers, which are assumed to remain unchanged.

8.2(a) Provide the model(s) Endeavour Energy used to forecast customer numbers and maximum demand.

Endeavour Energy does not have a specific model for developing maximum demand forecasts. A methodology has been developed and the details of this are summarised at 8.1 (a).

The models used to forecast Long-term and Short-term customer numbers are provided as Attachments D and E to this RIN.

8.2(b) Provide where Endeavour Energy's approach to weather correction has changed, provide historically consistent weather normalised maximum demand data, as per the format in regulatory templates 5.3 and 5.4 using Endeavour Energy's current approach. If this data is unavailable, explain why.

The current weather correction method has been used for all historical data for 2005/06 – 2012/13. Tables 5.3 and 5.4 contain historically consistent maximum demand data.

8.2(c) Provide for number of new connections, volume data requested in regulatory template 2.5.

The volume data for the number of new connections is provided in template 2.5 of the Microsoft Excel Workbooks at Attachment RIN.1-3

8.2(d) Provide any supporting information or calculations that illustrate how information extracted from Endeavour Energy forecasting model(s) reconciles to, and explains any differences from, information provided in regulatory templates 2.5, 5.3 and 5.4.

Endeavour Energy does not use customer connection numbers as an input to the demand forecasting methodology. The demand forecasting methodology output is used to populate table 5.3 and 5.4 therefore, there is no need to reconcile as it is the same data.

For future land release areas, planners use maximum lot release statistics to determine ultimate demand for the release area. The diversified demand is included into the forecast of the zone substation using an S-curve growth rate pattern over a specific period of time. This data is different to customer connection numbers and the forecast of new connections.

8.3(a) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain the models used.

A weather normalisation model is used to adjust the maximum demand to the reference temperatures. An air conditioning penetration rate model is to estimate the air conditioning penetration rates for each zone substation. The forecast demand for lot releases is estimated by a S-curve method. Future spot loads are diversified and added to the forecast. Planned load transfers are also included in the forecast for each zone substation.

8.3(b) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain a global (or top-down) and spatial (bottom-up) forecasting processes.

Endeavour Energy uses a bottom up approach for peak demand forecast.

8.3(c) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain the inputs and assumptions used in the models (including in relation to economic growth, customer numbers and policy changes and provide any associated models or data relevant to justifying these inputs and assumptions).

In summer, historical temperatures at Nowra are used for temperature correction of the maximum demand of the zone substation and subtransmission substations in the South Coast. Historical temperatures at Richmond are used for temperature correction of the maximum demand of the zone substation and subtransmission substations in the remaining Endeavour Energy areas. In winter, historical temperatures at Richmond are used for temperature correction of the maximum demand within the whole Endeavour Energy region.

The new developments planned to occur (lot releases) and new load increases expected from customer applications (spot loads) used in the forecast model are revised according to the latest economic growth and the change of customer demand. The total estimated solar generation over the forecast period is based on the current trend of number of PV installations and is adjusted to the forecasts at the network level.

8.3(d) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain the weather correction methodology, how weather data has been used, and how Endeavour Energy’s approach to weather correction has changed over time.

Temperature correction of historical peak demands aims to adjust the demands recorded at different temperature conditions to the corrected values which would have been experienced under similar (reference) temperature conditions with a set probability of occurrence.

In summer, two reference stations are employed for temperature correction of the maximum demand. One weather station at Nowra is used for the South Coast area which covers the Dapto Bulk Supply Point Region. The other weather station at Richmond is used for the remaining Endeavour Energy areas. In winter, one reference station at Richmond is used for temperature correction of the maximum demand within the whole Endeavour Energy region.

The 10% and 50% PoE reference temperatures were determined from a history of 50-year temperature data for Richmond and 55-year period for Nowra. The summer and winter reference temperatures are shown in Tables 1 and 2.

Table 1. Summer Reference Temperatures for South Coast and other remaining Endeavour Energy areas.		
Probability of Exceedence (PoE)	South Coast	Other Endeavour Energy Areas
	Max Temperature at Nowra (°C)	Max Temperature at Richmond (°C)
10% PoE	42.9	43.6
50% PoE	39.8	41.1

Table 2. Winter Reference Temperatures for the Endeavour Energy Region.	
Probability of Exceedence (PoE)	6 pm Temperature at Richmond (°C)
10% PoE	6.8

8.3(e) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain an outline of the treatment of block loads, transfers and switching within the forecasting process.

The planner's inputs in the forecasting methodology include new developments planned to occur (lot releases), new load increases expected from customer applications (spot loads) and also information regarding the future transfer of load from one zone substation to another (load transfers). The forecast demand for lot releases is further estimated by a S-curve method. The spot loads are diversified prior to inclusion in the forecast. These forecast demands from block loads are added to the base level forecast described in 8.1(a). The final forecast at a zone substation is derived from the base level forecast after adjustment for planned load transfers, spot loads, land releases and re-development in the zone substation area.

8.3(f) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain any appliance models, where used, or assumptions relating to average customer energy usage (by customer type).

Endeavour Energy uses a model based on independent survey data that specifies an 'experience curve' to determine the increasing penetration of air conditioners in an area over time. This model is used to determine the organic rate of growth in peak demand in residential areas.

8.3(g) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain 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 same forecasting methodology is used for each zone substation, Forecasts at transmission substations and bulk supply points are calculated by the corresponding historical diversity factors. A comparison is made between the previous forecast and actual data for the network to monitor the forecast performance. The air conditioning penetration rate model will be recalibrated if new survey data is available.

8.3(h) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain how the resulting forecast data is consistent across forecasts provided for each network element identified in regulatory template 5.4 and system wide forecasts.

The forecast for zone substations, subtransmission substations and the network level provided in regulatory template 5.3 and 5.4 follow the methodology described in 8.1(a) and 8.3(d) above.

8.3(i) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain how the forecasts resulting from these methods and assumptions have been used in determining the following: capital expenditure forecasts and operating and maintenance expenditure forecasts.

Capital expenditure forecasts

The 10 year demand forecasts are used in the annual Transmission Network Planning Review (TNPR (Attachment 5.05 to our regulatory proposal)). These forecasts are used as the basis of load flow analysis to determine if there are capacity or voltage constraints on the subtransmission

network including lines and substations. The TNPR (Attachment 5.05 to our regulatory proposal) includes the estimated year of constraint based on the load flow analysis and provides a trigger for further investigation to verify the constraints including ratings verification and load transfer capability. If the constraint is verified, a likely solution is put forward in capital expenditure forecasts over a 10 year period in the Strategic Asset Management Plan (SAMP).

Operating and maintenance expenditure forecasts.

Operating and maintenance forecast is carried out based on asset growth rates. Asset growth is a result of new customer connections and the organic growth of the network. Currently asset growth rate rates are calculated based on known major projects such as TS & ZS and historical data.

8.3(j) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain whether Endeavour Energy proposes to use the forecasting model(s) it used in the joint planning process for the purposes of its regulatory proposal

The demand forecasts are formally provided to Transgrid each year to facilitate joint planning processes. Proposed future projects that affect both Endeavour and Transgrid are considered in joint planning meetings.

8.3(k) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain whether Endeavour Energy forecasts both coincident and non-coincident maximum demand at the feeder, connection point, subtransmission 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).

Endeavour Energy forecasts non-coincident maximum demand at the zone substation for the 10% PoE and 50% PoE levels. Peak demand forecasts at transmission substations, bulk supply points and Endeavour Energy system level are calculated by the corresponding historical diversity factors and are also non-coincident. Endeavour Energy does not produce any coincident maximum demand forecast.

Sanity checks are made for the reasonableness of the forecast but there is no reconciliation of peak demand forecast at Endeavour Energy system level by an independent econometric model.

8.3(l) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain whether Endeavour Energy records historic maximum demand in MW, MVA or both.

Endeavour Energy records historic maximum demand in MW and MVA for most of the subtransmission substations and zone substations. MVA values are estimated from the assumed power factors, where there are no measurements.

8.3(m) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain the probability of exceedance that Endeavour Energy uses in network planning.

Endeavour Energy uses 50% probability of exceedance values for network planning.

8.3(n) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain the contingency planning process, in particular the process used to assess high system demand.

The annual Transmission Network Planning Review (Attachment 5.05 to our regulatory proposal) includes contingency analysis for N-1 scenarios. Endeavour Energy applies the 50% POE forecast demands in the contingency analysis carried out. For further details refer to the response to question 5.2(c) under the sub-heading 'major projects program'.

8.3(o) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain how risk is managed across the network, particularly in relation to load sharing across network elements and non-network solutions to peak demand events.

The annual Transmission Network Planning Review (Attachment 5.05 to our regulatory proposal) includes load flow analysis showing load in each network element in both normal and contingency scenario. As such if load is being shared unevenly due to a mismatch of impedance, the TNPR takes this into account. Operationally these risks can be managed by split bus configurations or changeover schemes. Demand Management agreements are put in place with customers where prudent to defer capital expenditure. This results in a reduction of load at risk on days with high load (for example a hot day event).

8.3(p) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain 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 Endeavour Energy's network.

Endeavour Energy compares the forecasts with those produced by TransGrid and other NSW distribution network service providers to monitor the trends of historical peak demand and to check the reasonableness of Endeavour Energy forecasts. AEMO does not produce a forecast that can be reconciled against Endeavour Energy's forecast.

8.3(q) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain how the normal and emergency ratings are used in determining capacity for individual zone substations and sub-transmission lines.

The annual TNPR (Attachment 5.05 to our regulatory proposal) identifies constraints initially based nameplate ratings of zone substation transformers and known ratings of subtransmission lines. Upon identification of the constraint further analysis is carried out to determine the availability of a cyclic or emergency rating. If there is additional emergency rating available that can be applied, this will defer a potential capital expenditure requirement.

8.3(r)(i) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(c), explain where Endeavour Energy proposes to commence or continue a Demand-Related Capex Project or Program during the Forthcoming regulatory control period on a HV feeder 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 assumed future load transfers between feeders, assumed feeder underlying load growth rates (exclusive of transfers and specific customer developments), assumed block loads, and associated demand assumptions.

A forecast of possible overloaded feeders has been developed to provide a proposed expenditure for the 2014/19 regulatory period.

The methodology used to create this forecast is as follows:

Zone Substation load growth rates were calculated using the demand forecast for each zone substation. These growth rates were applied to distribution feeders. Any feeder load that exceeded 240 Amps within the regulatory period due to the load growth rates were highlighted as potential overloaded feeders.

Future load transfers and block loads were considered by individual planners on a case by case basis. The planners also verified each potential overloaded feeder considering impacts of committed augmentation projects.

Refer to the Distribution Works Program, Attachment 5.26 to our regulatory proposal.

8.3(r)(ii) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain where Endeavour Energy proposes to commence or continue a Demand-Related Capex Project or Program during the Forthcoming regulatory control period on a HV feeder existing embedded generation capacity, and associated assumptions on the impact on demand levels.

Embedded generation that was activated during a peak event period is added back to the peak demand of the zone substation. Embedded generation that is normally on as a result of customer activity and is not accounted for in the zone substation demand is separately subtracted from the substation that is affected.

Where Endeavour Energy engages an embedded generator for peak demand reduction no Demand-Related Capex projects will proceed until the network peak demand increases to a point where network capacity is insufficient to safely and reliably supply the demand. Therefore, the assumptions on the impact of the demand levels are:

- Embedded generation performance where no specific performance agreements exist (eg solar PV) is incorporated in the load history and will continue unchanged into the future
- The engaged embedded generator will be available for demand reduction on request
- The agreed timing and quantity of demand reduction will be provided on request
- No diversity is to be allocated to the demand reduction level.

8.3(r)(iii) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain where Endeavour Energy proposes to commence or continue a Demand-Related Capex Project or Program during the Forthcoming regulatory control period on a HV feeder assumed future embedded generation capacity, and associated assumptions on the impact on demand levels.

Future committed embedded generation and associated assumptions are accounted for in the way described in (ii) above. No Demand-Related Capex projects will proceed until the network peak demand, inclusive of any embedded generation forecast, increases to a point where network capacity, inclusive of embedded generation, is insufficient to safely and reliably supply the demand.

8.3(r)(iv) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain where Endeavour Energy proposes to commence or continue a Demand-Related Capex Project or Program during the Forthcoming regulatory control period on a HV feeder existing non-network solutions, and the associated assumptions on the impact on demand levels.

Permanent demand reduction associated with a non-network option is not added back to the demand of the zone substation. It is considered business as usual once implemented.

Temporary demand reduction, such as load curtailment and embedded generation, is added back to the peak demand only for the days it was active to determine the true peak.

Where Endeavour Energy implements a non-network program for peak demand reduction no Demand-Related Capex projects will proceed until the network peak demand increases to a point where network capacity, inclusive of non-network solutions, is insufficient to safely and reliably supply the demand. Therefore, the assumptions on the impact of the demand levels are:

- The non-network solution will deliver the required demand reduction level
- The demand reduction acquired will target the peak demand on the network
- No diversity is to be allocated to the demand reduction level.

8.3(r)(v) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain where Endeavour Energy proposes to commence or continue a Demand-Related Capex Project or Program during the Forthcoming regulatory control period on a HV feeder assumed future non-network solutions, and associated assumptions on the impact on demand levels.

Future non-network solutions are investigated and implemented in a timely manner and are based on cost-effectively deferring or avoiding the preferred network option. Demand reductions and assumptions associated the non-network option are accounted for in the way described above. No Demand-Related Capex projects will proceed until the network peak demand increases to a point where network capacity, inclusive of forecast non-network solutions, is insufficient to safely and reliably supply the demand and the non-network solution exhausts all avenues for peak demand reduction.

8.3(r)(vi) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain where Endeavour Energy proposes to commence or continue a Demand-Related Capex Project or Program during the Forthcoming regulatory control period on a HV feeder the diversity between feeders.

Diversity between feeders is taken into account in specific circumstances where it is material. For example, when transferring load between industrial and residential feeders or when planning to double cable a feeder onto the same 11kV circuit breaker.

8.3(s)(i) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain for each zone substation (or relevant substations for a sub-transmission line) assumed future load transfers between related substations.

Assumed future load transfers, spot loads and growth rates are documented in the summer and winter demand forecast documents.

8.3(s)(ii) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain for each zone substation (or relevant substations for a sub-transmission line) assumed underlying load growth rates (exclusive of transfers and specific customer developments).

These assumptions are also documented in individual business cases for major projects where relevant.

8.3(s)(iii) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain for each zone substation (or relevant substations for a sub-transmission line) assumed specific customer developments, and associated demand assumptions.

These assumptions are also documented in individual business cases for major projects where relevant.

8.3(s)(iv) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain for each zone substation (or relevant substations for a sub-transmission line) existing embedded generation capacity, and associated assumptions on the impact on demand levels.

Future Demand-Related Capex projects are based on the current demand forecast which includes embedded generation as describe in (r)(ii) above.

8.3(s)(v) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain for each zone substation (or relevant substations for a sub-transmission line) assumed future embedded generation capacity, and associated assumptions on the impact on demand levels.

Future Demand-Related Capex projects are based on the current demand forecast which includes future committed embedded generation as describe in (r)(iii) above.

8.3(s)(vi) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain for each zone substation (or relevant substations for a sub-transmission line) existing non-network solutions, and the associated assumptions on the impact on demand levels.

Future Demand-Related Capex projects have been screened for non-network options in accordance with NER chapter 5 Part B, Network Planning and Expansion. Any feasible and cost effective non-network option would have been implemented and all potential demand reduction opportunities exhausted prior to implementing the network option as describe in (r)(iv) above.

8.3(s)(vii) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain for each zone substation (or relevant substations for a sub-transmission line) assumed future non-network solutions, and associated assumptions on the impact on demand levels.

Future Demand-Related Capex projects have been screened for non-network options in accordance with NER chapter 5 Part B, Network Planning and Expansion. Any feasible and cost effective non-network option would have been implemented and all potential demand reduction opportunities exhausted prior to implementing the network option as describe in (r)(iv) above.

8.3(s)(viii) For each of the methodologies provided and described in response to paragraph 8.1, and, where relevant, data requested under 8.2(b) and 8.2(d), explain for each zone substation (or relevant substations for a sub-transmission line) diversity with related substations.

Diversity between substations is taken into account in the forecast documents as both diversified and undiversified values at sub-transmission and bulk supply point level.

8.4(a) Provide evidence that any independent verifier engaged 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.

SKM MMA was engaged to conduct a high-level review of the spatial demand forecasting process and suggest further improvements. SKM MMA specialises in economic analysis and modelling, forecasting, financial modelling, strategic advice, asset valuation and pricing, policy development and regulatory advice.

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

The SKM MMA final report – Review of Endeavour Energy’s spatial demand forecast methodology, is attached at Attachment 5.19 to our regulatory proposal

9. Connections Expenditure Requirements

9.1(a) Provide and describe the methodology and assumptions used to prepare the forecasts of connections works as part of the connections program, including Estimation of connection unit costs for each customer type.

A detailed explanation is included in the Basis of Preparation.

Estimations were based on available and estimated financial data, the information available from internal reports and valuations taken from our AVS (Assert Valuation Sheet – Attachment F to this RIN) used to estimate the value of gifted assets provided by the developer.

9.1(b) Provide and describe the methodology and assumptions used to prepare the forecasts of connections works as part of the connections program, including connection volumes for each customer type.

A detailed explanation is included in the Basis of Preparation.

Estimations were based on available and estimated financial data, the information available from internal reports and valuations taken from our AVS (Assert Valuation Sheet) used to estimate the value of gifted assets provided by the developer.

9.2 Provide the estimation of customer contributions based upon the estimated life and revenue to be recovered from connection assets. This should include the calculation of the expected life of the connection, the average consumption expected by the customer over the life of the connection and any other factors that influence the expected recovery of the distribution network use of system charge to customers.

Basic explanation of methodology used for estimation is shown in 9.1 above. The AVS used by Endeavour Energy for estimating gifted assets is provided as Attachment F to this RIN.

Our estimation method is evident in the attached AVS model, our approach differs to the parameters suggested in question 9.2 (asset life, energy conveyed and average consumption.)

10. Operating and Maintenance Expenditure

Total forecast operating and maintenance expenditure (opex)

10.1(a) Provide the model(s) and methodology used to develop its total forecast opex.

To comply with the NER and to ensure that the nature of each cost category is appropriately accounted for in preparing the total forecast opex, we approach the development of the total forecast opex as follows:

- The base step trend 'revealed cost' approach was applied to the majority of Endeavour Energy's network maintenance activities, other operating costs and direct and indirect overhead forecast opex. This approach utilises an adjusted 2012/13 base year to forecast expenditure. We will forecast opex at the category or activity level, where appropriate.
- Other operating expenditure (including non-network alternative programs, self-insurance and debt raising costs) will be forecast using benchmark costs or individual project forecasts where appropriate.

For the activity level forecasts, we firstly developed forecast unit costs for the identified network maintenance activities using a trend based on 1 to 3 years of historical costs (inclusive of saving initiatives) which will be applied to the future Network Maintenance plan volumes for the 2014/15–2018/19 regulatory period to determine the Network maintenance operating expenditure forecasts.

In regards to the category level forecasts, we used the actual opex for the 2012/13 financial year (which is inclusive of saving initiatives) for the relevant operating expenditure categories as the base year opex to develop the 2014/15–2018/19 regulatory period forecast. This financial year is the fourth year of the current regulatory period and will be used because it is the latest actual opex data available at the time of preparing the forecast.

See our the 'operating expenditure forecasting method' section of our regulatory proposal and Attachment 0.08 to our regulatory proposal – forecasting methodology document for further information.

10.1(b)(i) Provide justification for Endeavour energy's total forecast opex, including why the total forecast opex is required for Endeavour Energy to achieve each of the objectives in clause 6.5.6(a) of the NER.

Refer to chapter 6 of the SRP in addition to Attachment 0.03 of our regulatory proposal.

10.1(b)(ii) Provide justification for Endeavour energy's total forecast opex, including how Endeavour Energy's total forecast opex reasonably reflects each of the criteria in clause 6.5.6(c) of the NER.

Refer to chapter 6 of the SRP in addition to Attachment 0.03 of our regulatory proposal.

10.1(b)(iii) Provide justification for Endeavour energy's total forecast opex, including how Endeavour Energy's total forecast opex accounts for the factors in clause 6.5.6(e) of the NER.

Refer to chapter 6 of the SRP in addition to Attachment 0.03 of our regulatory proposal.

10.2(a) Provide the quantum of non-recurrent costs for each year of the forthcoming regulatory control period.

Refer to table 2.6.1 – Non Network Expenditure in the Reset RIN Templates for the quantum of non-recurrent costs for each year of the forthcoming regulatory control period.

10.2(b) Provide an explanation of each non-recurrent cost.

The only capex non-recurrent costs are IT & Communications capex, which are costs to Develop New Capabilities and New business enabling technologies, examples include: Transformation, Strategic Re-engineering, Process Re-engineering, CRM, Mobility and AMI.

10.3(a) If Endeavour Energy used a revealed cost Base year approach to develop its total forecast opex, provide: the Base year Endeavour Energy used.

2012/13 was used as the base year for Endeavour Energy's revealed cost base year approach.

10.3(b) If Endeavour Energy used a revealed cost Base year approach to develop its total forecast opex, provide: explanation and justification for why that Base year represents efficient and recurrent costs.

The 2012/13 financial year is the fourth year of the current regulatory period and will be used because it is the latest actual opex data available at the time of preparing the forecast.

10.4(a) If Endeavour Energy did not use a revealed cost Base year approach to develop its total forecast opex, provide: forecast expenditure by Opex Category for each year of the forthcoming regulatory control period in Table 2.16.2 for standard control services opex, and if Endeavour Energy owns any dual function assets, Table 2.16.4 for dual function assets opex.

The base step trend 'revealed cost' approach was applied to the majority of Endeavour Energy's network maintenance activities, other operating costs and direct and indirect overhead forecast opex in developing our total forecast opex for the forthcoming regulatory period.

Refer to table 2.16.2 for Endeavour Energy's forecast expenditure by Opex Category for each year of the forthcoming regulatory control period for standard control services opex.

Endeavour Energy has a small number of sub-transmission lines and cables and transformers which could be potentially classified as dual function assets providing standard control services. These assets form transmission exit assets supporting Endeavour Energy's distribution network.

The value of these assets are immaterial and are within Endeavour Energy's existing distribution use of system (DUOS) pricing arrangements. The AER has acknowledged that changing the pricing approach to transmission pricing would not have a material impact on distribution prices and would incur administrative costs. Accordingly, the AER has determined that the distribution pricing will continue to apply for Endeavour Energy. Hence table 2.16.4 of regulatory template 2.16 is not applicable.

10.4(b) If Endeavour Energy did not use a revealed cost Base year approach to develop its total forecast opex, provide: in Microsoft Excel format, clear reconciliation (including all calculations and formulae) of Endeavour Energy's total forecast opex to: forecast standard control services opex by driver in Table 2.16.1, forecast standard control services opex by Opex Category in Table 2.16.2 and if Endeavour energy owns any dual function assets, Table 2.16.3 and Table 2.16.4 for dual function assets opex by Opex Category and driver respectively.

The base step trend 'revealed cost' approach was applied to the majority of Endeavour Energy's network maintenance activities, other operating costs and direct and indirect overhead forecast opex in developing our total forecast opex for the forthcoming regulatory period.

Refer to tables 2.16.1 and 2.16.2 for Endeavour Energy's forecast expenditure by Opex Driver and Opex Category for each year of the forthcoming regulatory control period for standard control services opex.

Endeavour Energy has a small number of sub-transmission lines and cables and transformers which could be potentially classified as dual function assets providing standard control services. These assets form transmission exit assets supporting Endeavour Energy's distribution network.

The value of these assets are immaterial and are within Endeavour Energy's existing distribution use of system (DUOS) pricing arrangements. The AER has acknowledged that changing the pricing approach to transmission pricing would not have a material impact on distribution prices and would incur administrative costs. Accordingly, the AER has determined that the distribution pricing will continue to apply for Endeavour Energy. Hence tables 2.16.3 and 2.16.4 are not applicable.

10.4(c) If Endeavour Energy did not use a revealed cost Base year approach to develop its total forecast opex, provide: 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.

The base step trend 'revealed cost' approach was applied to the majority of Endeavour Energy's network maintenance activities, other operating costs and direct and indirect overhead forecast opex in developing our total forecast opex for the forthcoming regulatory period.

Refer to tables 2.16.1 and 2.16.2 for Endeavour Energy's forecast expenditure by Opex Driver and Opex Category for each year of the forthcoming regulatory control period for standard control services opex.

10.4(d) If Endeavour Energy did not use a revealed cost Base year approach to develop its total forecast opex, provide: explanation and justification for: whether Endeavour Energy considers there is a year of historic opex that represents efficient and recurrent costs or why Endeavour Energy considers no year of historic opex represents efficient and recurrent costs.

The base step trend 'revealed cost' approach was applied to the majority of Endeavour Energy's network maintenance activities, other operating costs and direct and indirect overhead forecast opex in developing our total forecast opex for the forthcoming regulatory period.

2012/13 was used as the base year for Endeavour Energy's revealed cost base year approach as we consider this represents our efficient and recurrent base costs.

Refer to tables 2.16.1 and 2.16.2 for Endeavour Energy's forecast expenditure by Opex Driver and Opex Category for each year of the forthcoming regulatory control period for standard control services opex.

Output growth

10.5(a) Provide the amount of total forecast opex attributable to output growth changes for each year of the forthcoming regulatory control period in: Table 2.16.1 for standard control services opex.

The amount of total forecast opex attributable to output growth changes for each year of the forthcoming regulatory control period has been provided in Table 2.16.1

10.5(b) Provide the amount of total forecast opex attributable to output growth changes for each year of the forthcoming regulatory control period in: if Endeavour Energy owns any dual function assets, Table 2.16.3 for dual function assets opex.

Endeavour Energy has a small number of sub-transmission lines and cables and transformers which could be potentially classified as dual function assets providing standard control services. These assets form transmission exit assets supporting Endeavour Energy's distribution network.

The value of these assets are immaterial and are within Endeavour Energy's existing distribution use of system (DUOS) pricing arrangements. The AER has acknowledged that changing the pricing approach to transmission pricing would not have a material impact on distribution prices and would incur administrative costs. Accordingly, the AER has determined that the distribution pricing will continue to apply for Endeavour Energy. Hence table 2.16.3 of regulatory template 2.16 is not applicable.

10.6(a) Provide the output growth drivers Endeavour Energy used to develop the amount of total forecast opex attributable to output growth changes.

Output growth relates to increases in the number of activities and operations that Endeavour Energy is required to undertake as part of the efficient operations of the distribution network. For the 2014-19 period this growth is a result of growth in our customer numbers, network demand and our capital and operating programs during the 2009-14 period. As a result of this, we are required to maintain and operate a larger number of assets connected to our network. This creates a step up in our workload rather than unit costs.

The drivers for output growth include:

- Maintenance operations have been escalating due to the general increase in the number of assets being managed by Endeavour Energy and reduced forecast capital program. Further, this larger number of assets will require a greater number of inspections and preventative maintenance activities in order to extend the operational life of the assets being managed.
- The National Energy Customer Framework (NECF) imposes a range of obligations on the NSW DNSPs. Many of these obligations include activities that require staff to undertake either new activities or more of the same types of activities. For example, notifications of outages due to network maintenance and undertaking visual checks of the network configurations to ensure that all customers expected to be impacted by each outage have been identified and confirm that any customer with registered life support equipment has the required notice.
- Customer connection requests, in particular solar generator connection requests. Since the introduction of the NSW Solar Bonus Scheme (SBS) in 2010, Endeavour Energy has observed a marked increase in the number of connection requests that it receives from customers.

In addition, Endeavour Energy has identified the installation of rooftop PV generators as a potential community safety risk. Consequently we have been undertaking safety and compliance inspections on these installations at rates significantly greater than before the introduction of the SBS.

We also note that despite the SBS being closed as of 1 July 2012, the rate at which rooftop PV is being connected to our network has not reduced, and is therefore expected to continue to impact on the amount of work required in response.

10.6(b) Provide any economies of scale factors applied to the growth drivers.

Whilst no economies of scale factor is applied, our decreasing labour force and savings initiatives significantly offset the impact of these output growth factors. Refer to the 'cost savings initiatives during the 2014-19 period' section of Chapter 6 of our regulatory proposal for a quantification and description of these savings initiatives.

10.6(c) Provide evidence that the growth drivers explain cost changes due to output growth.

Refer to the attachments supporting chapter 5 and 6 of our regulatory proposal for evidence underpinning our proposed expenditure programs.

10.6(d) Provide if Endeavour Energy applied any composite multiple output growth drivers: the inputs for each composite multiple output growth driver and the weightings for each input.

Not applicable.

10.7(a) Provide an explanation of how, in developing the amount of total forecast opex attributable to output growth changes, Endeavour Energy: applied the output growth drivers.

Endeavour Energy does not calculate an overall output growth factor to forecast operating expenditure. The output growth drivers are incorporated through the volumes we use during our forecasting process.

Output growth drivers relating to capital expenditure reductions, which includes the application of the reduced NSW Design Planning Standards, have resulted in a reduced workforce being required by the end of the forthcoming period. Endeavour Energy has forecast direct labour reductions in line with the reducing capital program. The changing capital program and network growth in the current period has a direct increase in the maintenance expenditure required for the 2014-19 period. This increase was quantified and included as part of our operating expenditure forecast.

10.7(b) Provide an explanation of how, in developing the amount of total forecast opex attributable to output growth changes, Endeavour Energy: accounted for economies of scale.

Output growth drivers used in developing the forecast operating program are negative measures and consequently would more appropriately need to address reducing economies of scale, rather than the implied increase in economies of scale. Endeavour Energy has not forecast any scale economy losses arising from the reducing labour force or output measures forecast in the regulatory proposal. Endeavour has however identified areas where output growth rates may require additional expenditures.

Real price changes

10.8(a) Provide the amount of total forecast opex attributable to changes in the price of labour and material prices for each year of the forthcoming regulatory control period in: Table 2.16.1 for standard control services opex.

The amount of total forecast opex attributable to changes in the price of labour and material prices for each year of the forthcoming regulatory control period have been provided in Table 2.16.1 for standard control services opex in the Microsoft Excel Workbooks at Attachment RIN.1-3.

10.8(b) Provide the amount of total forecast opex attributable to changes in the price of labour and material prices for each year of the forthcoming regulatory control period in: if Endeavour Energy owns any dual function assets, Table 2.16.3 for dual function assets opex.

Endeavour Energy has a small number of sub-transmission lines and cables and transformers which could be potentially classified as dual function assets providing standard control services. These assets form transmission exit assets supporting Endeavour Energy's distribution network.

The value of these assets are immaterial and are within Endeavour Energy's existing distribution use of system (DUOS) pricing arrangements. The AER has acknowledged that changing the pricing approach to transmission pricing would not have a material impact on distribution prices and would incur administrative costs. Accordingly, the AER has determined that the distribution pricing will continue to apply for Endeavour Energy. Hence table 2.16.3 of regulatory template 2.16 is not applicable.

10.9(a) Provide an explanation of: how, in developing the amount of total forecast opex attributable to changes in the price of labour and materials, Endeavour Energy applied the real price measures in regulatory template 2.14.

Real labour escalators, calculated based on template 2.14, were added to all labour related costs as follows:

- "Labour - WPI all – FY" escalators were applied to all contract staff.
- "Labour - util.- Endeavour – FY" escalators were applied to all award staff. These were also applied to all overtime and allowances as contract staff are not entitled to these payments. They were also applied to temp staff costs as temps are generally filling award based roles rather than contract roles which tend to be more of a managerial nature.
- The above escalation factors were applied at an individual employee level across the business. The impact was then split between opex and capex at an individual employee level where possible or otherwise based on the overall opex / capex labour cost split for each responsibility centre.

Refer to attachments 0.04, 0.05 and 5.20 of our regulatory proposal for further details of these escalators.

10.9(b) Provide an explanation of: whether Endeavour Energy's labour price measure compensates for any form of labour productivity change

Refer to attachment 0.05 of our regulatory proposal for further details of these escalators. Consistent with the AER's recent determinations we have used the WPI as a measure of wage growth without a productivity adjustment. As noted in Attachment 0.05:

In its determinations, the AER has noted that it should adjust growth in labour costs for growth in productivity. This is because it is changes in the nominal unit cost of labour (the cost of labour per unit of output) that provides a justification for price changes. Thus, price changes should take into account the percentage movement in the price of labour net of the percent gain in labour productivity. However, as acknowledged by the AER, it is not possible to adjust the WPI for growth in productivity because there is no published measure of productivity that is consistent with it. Given this difficulty, the AER has decided to use the WPI but make no adjustment for productivity.....

.....It is inappropriate to use the WPI in conjunction with an incompatible measure of labour productivity. In particular, labour cost and labour productivity adjustments can only be validly used in tandem if they are based on the same concept of labour input.

Productivity change

10.10(a) Provide the amount of total forecast opex attributable to changes in productivity for each year of the forthcoming regulatory control period in: Table 2.16.1 for standard control services opex.

The amount of total forecast opex attributable to changes in productivity for each year of the forthcoming regulatory control period has been provided in Table 2.16.1 for standard control services opex.

10.10(b) Provide the amount of total forecast opex attributable to changes in productivity for each year of the forthcoming regulatory control period in: if Endeavour Energy owns any dual function assets, Table 2.16.3 for dual function assets opex.

Endeavour Energy has a small number of sub-transmission lines and cables and transformers which could be potentially classified as dual function assets providing standard control services. These assets form transmission exit assets supporting Endeavour Energy's distribution network.

The value of these assets are immaterial and are within Endeavour Energy's existing distribution use of system (DUOS) pricing arrangements. The AER has acknowledged that changing the pricing approach to transmission pricing would not have a material impact on distribution prices and would incur administrative costs. Accordingly, the AER has determined that the distribution pricing will continue to apply for Endeavour Energy. Hence table 2.16.3 of regulatory template 2.16 is not applicable.

10.11 Provide, in percentage year on year terms, the productivity measure that Endeavour Energy used to develop the amount of total forecast opex attributable to changes in productivity.

The productivity growth in table 2.16.1 for the forthcoming regulatory control period represents the actual cost reduction programs Endeavour Energy has implemented in the current 2009-14 regulatory control period and is not a percentage productivity measure. These cost reduction programs were primarily driven by productivity based initiatives and the introduction of the Network Reform Program.

Refer to chapter 6 of the SRP for additional information on the cost reduction programs Endeavour Energy has included in developing the amount of total forecast opex attributable to changes in productivity.

The below table illustrates the programs included in the total forecast opex and the changes year on year from the 2012/13 base year:

\$m; Real 2013/14	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
C7 Program	27.3	26.8	25.0	24.9	24.8	24.8	24.8	124.3
Project Challenge	19.4	27.0	21.7	21.8	21.7	21.8	21.8	108.7
Project Compete	4.1	6.3	6.2	6.2	6.2	6.2	6.2	30.9
Network Reform	0.1	2.9	5.6	8.7	8.7	8.7	8.7	40.3
Total Cost Reduction	51.0	63.1	58.5	61.5	61.4	61.4	61.4	304.2
% Change from 2012/13	-	23.7%	14.7%	20.5%	20.5%	20.5%	20.5%	-

10.12(a) Provide an explanation of: how, in developing the amount of total forecast opex attributable to changes in productivity, Endeavour Energy applied the productivity measure in 10.11.

The productivity growth in table 2.16.1 for the forthcoming regulatory control period represents the actual cost reduction programs Endeavour Energy has implemented in the current 2009-14 regulatory control period and is not a percentage productivity measure. These cost reduction programs were primarily driven by productivity based initiatives and the introduction of the Network Reform Program.

Refer to chapter 6 of our regulatory proposal and Attachment 0.02 to our regulatory proposal: 'Delivering efficiencies for our customers' for additional information on the cost reduction programs Endeavour Energy has included in developing the amount of total forecast opex attributable to changes in productivity.

10.12(b) Provide an explanation of: whether Endeavour Energy's forecast productivity changes capture the historic trend of cost increases due to changes in regulatory obligations or requirements and industry best practice.

The productivity improvements for forecast opex do not include increases in the required opex due to regulatory obligation impacts expected over the forthcoming regulatory period.

Overall summary productivity movements as observed from the forecast opex include the outcome of changing regulatory obligations such as those imposed by the previous Design Planning Licence conditions, as well as any step changes arising from the targeted capital expenditure program.

10.12(c) Provide an explanation of: whether Endeavour Energy's productivity measure includes productivity change compensated for by the labour price measure used by Endeavour Energy to forecast the change in the price of labour.

Refer to attachment 0.05 of our regulatory proposal for further details of the labour price measured used. Consistent with the AER's recent determinations we have used the WPI as a measure of wage growth without a productivity adjustment. As noted in Attachment 0.05:

In its determinations, the AER has noted that it should adjust growth in labour costs for growth in productivity. This is because it is changes in the nominal unit cost of labour (the cost of labour per unit of output) that provides a justification for price changes. Thus, price changes should take into account the percentage movement in the price of labour net of the percent gain in labour productivity. However, as acknowledged by the AER, it is not possible to adjust the WPI for growth in productivity because there is no published measure of productivity that is consistent with it. Given this difficulty, the AER has decided to use the WPI but make no adjustment for productivity.....

.....It is inappropriate to use the WPI in conjunction with an incompatible measure of labour productivity. In particular, labour cost and labour productivity adjustments can only be validly used in tandem if they are based on the same concept of labour input.

Opex step changes

10.13(a) Provide the amount of total forecast opex attributable to opex step changes for each year of the forthcoming regulatory control period in: Table 2.16.1 for standard control services opex.

The amount of total forecast opex attributable to opex step changes for each year of the forthcoming regulatory control period has been provided in Table 2.16.1 for standard control services opex.

10.13(b) Provide the amount of total forecast opex attributable to opex step changes for each year of the forthcoming regulatory control period in Table 2.16.3 for dual function assets opex if Endeavour Energy owns any dual function assets.

Endeavour Energy has a small number of sub-transmission lines and cables and transformers which could be potentially classified as dual function assets providing standard control services. These assets form transmission exit assets supporting Endeavour Energy's distribution network.

The value of these assets are immaterial and are within Endeavour Energy's existing distribution use of system (DUOS) pricing arrangements. The AER has acknowledged that changing the pricing approach to transmission pricing would not have a material impact on distribution prices and would incur administrative costs. Accordingly, the AER has determined that the distribution pricing will continue to apply for Endeavour Energy. Hence table 2.16.3 of regulatory template 2.16 is not applicable.

10.14(a) Provide an explanation of why Endeavour Energy considers: the efficient costs of the Step change are not provided by other components of Endeavour Energy's total forecast opex such as, base opex, output growth changes, real price changes or productivity change.

Endeavour Energy has considered all drivers of the variance of actual / forecast opex expenditure compared to the AER allowance and for the current regulatory period has concluded the following:

- The retail dis-synergy costs are considered to be a step change in table 2.17.1 and are included in the row called step changes in table 2.16.1; and
- The vegetation management costs are considered to be a step change in table 2.17.1 and are included in the row called step changes in table 2.16.1.

For the forthcoming regulatory period Endeavour Energy has concluded the following:

- The retail dis-synergy costs are considered to be a step change in table 2.17.1 and are included in the row called step changes in table 2.16.1;
- The vegetation management costs are considered to be a step change in table 2.17.1 and are included in the row called step changes in table 2.16.1;
- The real cost escalation is considered to be "Real price change" driver in table 2.16.1 and not a step change in table 2.17.1 in the regulatory templates;
- The growth in the underlying asset base during 2009-14 results in a growth in the opex attributable to standard control services and is considered to be a "Output growth" driver in table 2.16.1 and not a step change in table 2.17.1 in the regulatory templates; and
- The actual cost reduction programs are considered to be "Productivity growth" driver in table 2.16.1 and not a step change in table 2.17.1 in the regulatory templates.

Refer to chapter 6 of the SRP for additional information on the opex step changes.

10.14(b) Provide an explanation of why Endeavour Energy considers: the total forecast opex will not allow Endeavour Energy to achieve the objectives in clause 6.5.6(a) of the NER unless the Step change is included

The step changes form part of our total forecast opex, Endeavour Energy's total forecast opex is required to achieve each of the opex objectives.

This is explained in the 'Meeting the Rules' section in chapter 6 of our regulatory proposal and Attachment 0.03 to our proposal: 'Addressing the capex and opex objectives, criteria and factors'. The supporting opex attachments to our regulatory proposal also provide further justification.

10.14(c) Provide an explanation of why Endeavour Energy considers: 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.

The step changes form part of our total forecast opex. Endeavour Energy's total forecast opex reasonably reflects each of the opex criteria.

This is explained in the 'Meeting the Rules' section in chapter 6 of our regulatory proposal and Attachment 0.03 to our proposal: 'Addressing the capex and opex objectives, criteria and factors'. The supporting opex attachments to our regulatory proposal also provide further justification.

Vegetation management

10.15 Provide compliance audits of vegetation management work conducted by Endeavour Energy during the current regulatory control period.

Copies of compliance audits of vegetation management work conducted by Endeavour Energy during the current regulatory control period are provided at Attachment G to this RIN.

11. Risk Management and Insurance

Risk management framework

11.1(a) Provide information that sets out Endeavour Energy's governance arrangements in relation to the management of risk, including a risk appetite statement, which details the level of risk, Endeavour Energy's board is willing to accept including the nature and level of risks and the level of loss that can be sustained.

Endeavour Energy is committed to achieving a positive culture of risk management based on the proactive and systematic identification and management of risk that enables effective delivery of the Corporate Plan. The risk appetite is identified in the Common Risk Matrix which is included in the Risk Management Board Policy. The risk matrix considers likelihood criteria and consequence criteria, specifically relating to Safety, Network, Finance, Compliance, Reputation and Environmental impacts. The Financial impacts are shown in the table below.

Insignificant	Minor	Moderate	Major	Severe
<= \$250K	\$250K to \$5M	\$5M to \$25M	\$25M to \$50M	>\$50M

11.1(b) Provide information that sets out Endeavour Energy's governance arrangements in relation to the management of risk, including a risk management strategy that describes Endeavour Energy's strategy for managing risk and the key elements of the risk management framework that give effect to this strategy.

In 2012/13, Endeavour Energy, together with Ausgrid and Essential Energy, implemented a revised common risk management framework that enables us to identify and manage risks that could affect customers, the community, environment, our people, assets and financial resources.

For the 2013/14 year Endeavour Energy reviewed major risks to our strategic objectives and developed and implemented action plans to help manage them.

Our management of business risk is based on three key behaviours:

- We are aware of our activities, operations and objectives.
- We consider what can go wrong and the consequences.
- We take action to prevent what can go wrong.

Also implemented were initiatives outlined in the risk management strategy to strengthen risk management practices across the company.

Both the Risk Management Strategic Plan and Corporate Risk Management Plan are reviewed by the Audit and Risk Committee of the Board throughout the year. 'Risk owners' provide regular reports to management and to the Audit and Risk Committee on the results of ongoing monitoring and review of risks, and on action plans to manage them. Risks which may impact on the achievement of our Corporate Plan are continually identified and assessed across nine categories, as shown in the table below.

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BR Number	Risk Category	Generic Risk Description	Risk Category Owner
BR 1	Safety	Fatality/serious injury of employee or member of public	General Manager Health, Safety & Environment
BR 2	Network	Significant customer impact related to the Network	Chief Engineer
BR 3	Finance	Significant unbudgeted financial loss	General Manager Finance & Compliance
BR 4	Compliance	Liability associated with a dispute or material breach of legislation, licence	General Manager Finance & Compliance
BR 5	Reputation	Sustained public criticism of Endeavour Energy	General Manager People & Services
BR 6	Environment	Significant environmental incident	General Manager Health, Safety & Environment
BR 7	People	Failure to deliver performance through people	General Manager People & Services
BR 8	Strategy	Strategic objectives are not delivered and business opportunities are lost	Chief Executive Officer
BR 9	ICT	Significant ICT & OT system failure	General Manager Information, Communications & Technology

11.1(c) Provide information that sets out Endeavour Energy's governance arrangements in relation to the management of risk, including any other information that demonstrates Endeavour Energy's governance arrangements in relation to risks and their management.

Emerging risks, key risk indicators, the status of treatment action plans and progress against the Risk Management Strategic Plan are reported via the Executive Audit, Risk and Compliance Committee to the Audit and Risk Committee of the Board.

Insurance (regulatory template 2.15)

11.2(a) General Instructions: Table 2.15.1 must provide a summary of all Endeavour Energy's proposed insurance costs.

A summary of all Endeavour Energy's proposed insurance costs are provided in regulatory template 2.15.1. Regulatory template 2.15.1 is part of the Microsoft Excel Workbooks at Attachment RIN.1-3.

11.2(b) General Instructions: Tables 2.15.2 and 2.15.3 seek more detailed information regarding total property and liability premiums only. The total property premiums forecast in table 2.15.2 must equal the sum of the premium forecasts classed as property insurance in table 2.15.1. The total liability forecast in table 2.15.3 must equal the sum of the premium forecasts classed as liability insurance in table 2.15.1.

Regulatory templates 2.15.1, 2.15.2 and 2.15.3 have been completed in accordance with the General Instructions. Regulatory templates 2.15.1, 2.15.2 and 2.15.3 are part of the Microsoft Excel Workbooks at Attachments RIN.1-3

11.2(c) General Instructions: Amounts are exclusive of GST.

Amounts are exclusive of GST.

11.3(a) Provide the following information for each commercially insured risk listed in table 2.15.1: the name and description of each insured risk, including policy limits and sub-limits.

Endeavour Energy has provided the name and description of each insured risk, including policy limits and sub-limits in regulatory template 2.15.1. Regulatory template 2.15.1 is part of the Microsoft Excel Workbooks at Attachments RIN.1-3

11.3(b) Provide the following information for each commercially insured risk listed in table 2.15.1: a description of the general method used to forecast premiums (this may be in the form of an insurance premium forecast report by a qualified risk specialist).

Endeavour Energy's brokers, Aon and Marsh, provide premium/rate estimates. Endeavour Energy then adjusts the Property insurance to factor in any new assets coming on stream after acquisition and/or construction and CPI.

11.3(c) Provide the following information for each commercially insured risk listed in table 2.15.1: any changes in insurance cover between the current and forthcoming regulatory control periods.

No changes in insurance cover, however policy limits, excess levels and extent of coverage are reviewed annually based upon updated risk information and insurance market conditions which are cyclical.

11.4(a) Provide the following information regarding total property and total liability insurance reported in tables 2.15.2 and 2.15.3 respectively: a description of the systematic drivers of insurance premiums.

The systematic drivers of insurance premiums for Endeavour Energy are Endeavour Energy's and global claims experiences, reinstatement values, risk management procedures, limits purchased and deductible levels, available market capacity that is capital movements in the insurance market, cyclical insurance market, insurance market relationships and ability to successfully sell Endeavour Energy's risks.

11.4(b) Provide the following information regarding total property and total liability insurance reported in tables 2.15.2 and 2.15.3 respectively: a description of the circumstances that have led to any premium changes over the current regulatory control period.

The circumstances that have led to premium changes over the current regulatory control period are insurance market rates/conditions and reinstatement value and other metrics e.g. number of vehicles (used by insurers to calculate premium) movements and bushfire probability analysis. Internal premium allocation methodology for the Group fire and general liability insurance program (GLIS), where Ausgrid, Endeavour Energy and Essential Energy (the Group) jointly purchase insurance, has a variable claims element which can result in premium changes (see 11.5 a) See 11.3 b).

11.4(c) Provide the following information regarding total property and total liability insurance reported in tables 2.15.2 and 2.15.3 respectively: a description of the method used to forecast premiums for the forthcoming regulatory control period, including estimated exposure growth and premium rate changes and any other adjustments made. Provide supporting evidence for exposure, premium rate changes, or any other proposed adjustments.

Endeavour Energy reviews and establishes policy limits in conjunction with its broker each year. Endeavour Energy establishes property reinstatement values and other risk metrics each year and considers these to review/consider accumulation risk/values.

11.4(d) Provide the following information regarding total property and total liability insurance reported in tables 2.15.2 and 2.15.3 respectively: an explanation of how the value of insured assets is derived for property insurance (e.g. replacement costs, insured value etc.).

Replacement costs are used.

11.5(a) Where insurance is shared with other entities, provide: an explanation of the cost allocation approach used for each risk class.

Insurers provide the premium allocations based upon values declared, numbers of vehicles, etc. except for GLIS (See 11.4 b)).

GLIS has been allocated based upon an agreed internal premium allocation methodology for its entire 26 year history. The methodology has been reviewed and approved by brokers and actuaries as well as the subject specialists within the Group over the years. Amendments have been made from time to time.

The following is the current premium allocation methodology:

- *The Group Insurance Committee (GIC) consider the broker's recommendations as to the estimated premium and the split between Fire and General Liability (GL) which will be used in the formula. The GIC will also review annually any other issues that may impact on the allocation to ensure fairness to all parties.*
- *Maintain the Fire premium allocation percentage/formula previously established (ie based on a number of factors such as population, length of lines, rainfall, vegetation, area etc) to apply to the Fire content of premium.*
- *Each year 50% of the G L premium proportion to be allocated based on the insured claims performance of each member for the previous five (5) full insurance years as a percentage of the Group insured claims for the same period as at 31st December each year and capping anyone claim at \$500,000. ie the maximum amount for any claim included in the formula is \$500,000. Also adjusting for sold businesses.*
- *Each year 50% of the GL premium proportion to be allocated based upon each member's customer numbers as a % of the Group customer numbers.*

This methodology means the overall proportion allocated to each of the Group can change each year mainly due to the GL claims element of the formula.

Table 1 details the last four years allocations:

Table 1

	GLIS LIABILITY PREMIUM ALLOCATION			
	2014/15	2013/14	2012/13	2011/12
Ausgrid	32.42%	34.81%	40.32%	38.64%
Endeavour Energy	25.49%	23.84%	21.83%	21.71%
Essential Energy	42.09%	41.34%	37.85%	39.65%
Total	100%	100%	100%	100%

11.5(b) Where insurance is shared with other entities, provide: cost allocations (percentage by risk class for the current regulatory control periods).

The only insurance premium shared with other entities is the GLIS. See response to 11.5 (a) above for details on the cost allocations,

11.5(c) Where insurance is shared with other entities, provide: the cost allocation (percentage) that underlies forecast premiums for the forthcoming regulatory control period. If the proportion allocated to Endeavour Energy has changed, explain why.

The Group Liability Insurance Scheme (GLIS) premium is allocated as set out in the response to question 11.5(a). The table above (see 11.5(a)) details the premium allocation across the three NSW DNSPs for recent and upcoming financial years.

It is expected that the 2014/15 allocation will apply for the following 4 years, up to and including 2018/2019, of the regulatory control period. However, 50% of the premium for each financial year is allocated on the basis of the claims experience of each entity during that year. As future claims and costs cannot be known, the premium allocation for the 2014/15 financial year is applied subject to any variation required as a result of insurance claims.

11.6 Provide a report from an appropriately qualified risk specialist verifying that Endeavour Energy's forecast insurance premiums are efficient.

Ernst & Young provided Endeavour Energy with a report which is provided at Attachment 6.13 to our regulatory proposal. Also, our brokers, March and Aon, advised the forecast premiums/rates.

Self-insurance

11.7(a) For each risk for which Endeavour Energy is proposing a self-insurance allowance in the regulatory proposal: provide a description of the risk and risk exposure including cover, exclusions and limit.

Endeavour Energy has provided a description of the risk and risk exposure including cover, exclusions and limit in regulatory template 2.15.4. Regulatory template 2.15.4 is part of the Microsoft Excel Workbooks at Attachments RIN.1-3.

11.7(b) For each risk for which Endeavour Energy is proposing a self-insurance allowance in the regulatory proposal: explain how each self-insurance allowance has been calculated describing the modelling and detailing key assumptions.

External insurers currently provide Excess of Loss Worker's Compensation insurance for Endeavour Energy, but require a \$500,000 deductible as part of the policy terms and conditions of providing this insurance below which Endeavour Energy must self-insure.

11.7(c) For each risk for which Endeavour Energy is proposing a self-insurance allowance in the regulatory proposal: provide a record of historic losses and claims against the self-insurance fund as far as records allow.

A record of historic losses and claims is provided in the Appendices to the report from David A Zaman, Consulting Actuary, provided in response to paragraph 11.9 below, Attachment H to this RIN.

11.7(d) For each risk for which Endeavour Energy is proposing a self-insurance allowance in the regulatory proposal: explain why compensation should be provided for the risk. Where insurance is available from a commercial insurer and an insurance quote has been obtained, provide evidence that it is more efficient to self-insure for that risk.

Compensation for the risk is mandated by state legislation. The Aon Report dated June 2013 - Appendix 2 – Comparison – Self Insurance to Insurance estimated that Endeavour Energy would receive a saving of \$ 2,838,801.00 in 2011/12 as a Self-Insurer compared to being fully insured under the scheme as further illustrated in table below:

Endeavour Energy

Year	Projected cost of self-insurance	Projected Cost of insurance	Projected Savings
2011/12	3,151,199	5,990,000	2,838,801
% of payroll	0.96%	1.83%	0.87%

* Assessed as a conventional policy premium

** Based on actuarial assessment of claims liabilities multiplied by 1.75 plus dust disease levy

11.7(e) For each risk for which Endeavour Energy is proposing a self-insurance allowance in the regulatory proposal: confirm that the risk for which self-insurance is being sought is not recovered through any other mechanism.

Endeavour Energy is proposing a self-insurance allowance in the regulatory proposal for Workers Compensation. It is confirmed that this risk is not being recovered through any other mechanism.

11.7(f) For each risk for which Endeavour Energy is proposing a self-insurance allowance in the regulatory proposal: explain why, if a self-insurance allowance has not been sought for a particular risk in the 2009–10 to 2013–14 regulatory control period, explain why it is being sought in the 2014–15 to 2018–19 regulatory control period.

Endeavour Energy sought and received an allowance for Workers Compensation self-insurance risk in the 2009-10 to 2013-14 regulatory control period. This allowance is also being sought for the 2014-15 to 2018-19 regulatory control period. There are no other self-insurance allowances proposed in the regulatory proposal.

11.8(a) If Endeavour Energy is proposing self-insurance for asset failure risk in the revenue proposal provide the annual number of failures for each asset category for which self-insurance is being sought, the historical costs for each asset failure and describe what those costs relate to, including a split between capex and opex.

Endeavour Energy is not proposing a self-insurance allowance for asset failure risk in the regulatory proposal.

11.8(b)(i) If Endeavour Energy is proposing self-insurance for asset failure risk in the revenue proposal explain where the self-insurance allowance is not based on the actual historical asset failure rates and costs, how the allowance has been forecast and why it is efficient.

Endeavour Energy is not proposing a self-insurance allowance for asset failure risk in the regulatory proposal.

11.8(b)(ii) If Endeavour Energy is proposing self-insurance for asset failure risk in the revenue proposal explain how the proposed capex has been taken into account in calculating the probability of asset failure for each asset category for which self-insurance is being sought.

Endeavour Energy is not proposing a self-insurance allowance for asset failure risk in the regulatory proposal.

11.9 Provide a report from an appropriately qualified actuary or risk specialist verifying the calculation of risk and corresponding self-insurance premiums.

A report from David A Zaman Pty Ltd, Consulting Actuary, is provided as Attachment H to this RIN.

12. Alternative Control Services and Other Activities

12.1 The overheads relating to each alternative control service or Other Activity must be disclosed in accordance with paragraph 12.2.

Fee-Based & Quoted Alternative Control Services (Ancillary Network Services):

- Refer to Attachment I to this RIN which provides the direct expenditure, network and corporate overhead and total expenditure related to each Ancillary Network Service for each year in the forthcoming regulatory control period. It should be noted that the expenditure presented in worksheet 12.1(a) of Attachment I is in real 2013/14 dollars in order to align with the expenditure reported in tables 4.3 and 4.4 of the Reset RIN.

- Refer to Attachment I to this RIN which provides the proposed fees related to each Ancillary Network Service and splits these between their direct expenditure component and the network and corporate overhead component. It should be noted that the fees presented in worksheet 12.1(b) of Attachment I are in nominal dollars for the relevant year. For further details in relation to the calculation of proposed fees for each Ancillary Network Service refer to the Fee Methodology documents attached to the Substantive Regulatory Proposal (Attachment 8.09).

Metering Alternative Control Services (Type 5 & 6 Metering Services):

- Refer to Attachment I which provides the direct expenditure, network and corporate overhead and total expenditure related to Metering Alternative Control Services for each year in the forthcoming regulatory control period. Given the focus of question 12.1 is in relation to the individual services that Endeavour Energy intends to levy charges, the expenditure reported in worksheet 12.1(c) of Attachment I is the total Metering Alternative Control Services **recoverable costs** calculated in the Metering Service Charge model (attached to the Substantive Regulatory Proposal). Total Metering Alternative Control Services recoverable costs does not reconcile to the expenditure reported in table 4.2.2 of the Reset RIN as total recoverable costs include the recovery of opening RAB, in addition to provisions for a return on invested capital (refer to the Metering Service Charge model for detailed calculations of annual recoverable costs). As a result, total recoverable costs and capital expenditure amounts reported in worksheet 12.1(c) cannot be reconciled to the figures reported in table 4.2.2 in the Reset RIN. Table 4.2.2 of the Reset RIN represents only expenditure incurred during the year and does not include opening RAB recovery or provisions for a return on invested capital.

- Refer to Attachment I which provides the proposed fees related to each Metering Alternative Control Service charge category and splits these between their direct expenditure component and the network and corporate overhead component. It should be noted that the fees presented in worksheet 12.1(d) of Attachment I are in nominal dollars for the relevant year. For further details in relation to the calculation of proposed fees for each Metering Alternative Control Service charge category, refer to the Metering Service Charge model attached to the Substantive Regulatory Proposal (Attachment 0.17).

Public Lighting Alternative Control Services

- Refer to Attachment I which provides the direct expenditure, network and corporate overhead and total expenditure related to Public Lighting Alternative Control Services for each year in the forthcoming regulatory control period. Given the focus of question 12.1 is in relation to the individual services that Endeavour Energy intends to levy charges, the expenditure reported in worksheet 12.1(e) is the total Public Lighting Alternative Control Services recoverable costs

calculated in the Public Lighting model (attached to the Substantive Regulatory Proposal). Total Public Lighting Alternative Control Services recoverable costs does not reconcile to the expenditure reported in table 4.2.2 of the Reset RIN as total recoverable costs include the recovery of residual asset values, the NPV of tax losses arising from capital contributions, in addition to provisions for a return on invested capital (refer to the Public Lighting model for detailed calculations of annual recoverable costs). As a result, total recoverable costs and capital expenditure amounts reported in worksheet 12.1(e) cannot be reconciled to the figures reported in the Reset RIN. The Reset RIN represents only expenditure incurred during the year and does not include residual asset value recovery, recovery of the NPV of income tax costs arising from the receipt of gifted assets or provisions for a return on invested capital.

- Refer to Attachment I which provides the proposed fees related to each Public Lighting Alternative Control Service charge category and splits these between their direct expenditure component and the network and corporate overhead component. It should be noted that the fees presented in worksheet 12.1(f) are in nominal dollars for the relevant year. For further details in relation to the calculation of proposed fees for each Public Lighting Alternative Control Service charge category, refer to the Public Lighting model attached to the Substantive Regulatory Proposal (Attachment 0.16).

12.2 Provide a list of all of the individual services that Endeavour Energy intends to provide and levy charges for in the forthcoming regulatory control period that fit within the broader definitions of distribution services that the AER proposed to classify as alternative control services in the Framework and Approach Paper.

A list of all of the individual services that Endeavour Energy intends to provide and levy charges for in the forthcoming regulatory control period that fit within the broader definitions of distribution services that the AER proposed to classify as alternative control services in the Framework and Approach Paper is provided at Attachment 0.18 to our regulatory proposal.

12.3 Provide a definition of each alternative control service listed in paragraphs 13, 14 and 15, where Endeavour Energy proposes a classification different to that in the Framework and Approach Paper.

Endeavour Energy is not proposing a classification of alternative control services that is different to that in the Framework and Approach Paper.

12.4 For each alternative control service listed in paragraphs 13, 14 and 15, 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.

The alternative control service charges applicable during each year of the current regulatory control period and the proposed charges for each year of the forthcoming regulatory control period are provided at Attachment 0.18 to our regulatory proposal.

12.5 For each alternative control service listed in paragraphs 13, 14 and 15, specify the total revenue earned by Endeavour Energy in each year of the current regulatory control period and forthcoming regulatory control period.

Fee-Based & Quoted Alternative Control Services (Ancillary Network Services):

- Total forecast revenue to be earned from Ancillary Network Services in the forthcoming regulatory control period is disclosed in table 3.1 of the Reset RIN as 'Revenue from Other Sources' (variable code DREV0112). In accordance with the Transitional Rules, Endeavour Energy are only allowed to escalate prices for existing Ancillary Network Services by CPI for the 2014/15 year. As a result, the alternative control services revenue forecast to be earned from

Ancillary Network Services in 2014/15 is significantly lower than the annual forecast revenue to be earned from 2015/16 to 2018/19. Note: figures reported for the forthcoming regulatory control period in table 3.1 are in real 2013/14 dollars.

- In addition, the AER can refer to the Fee Methodology documents attached to the Substantive Regulatory Proposal (Attachment 8.09) which disclose the forecast revenue to be earned from the provision of individual Ancillary Network Services for the forthcoming regulatory control period. However, it should be noted that the Fee Methodology documents do not reflect the Transitional Rules and assume full recovery of Ancillary Network Service expenditure in 2014/15. All figures contained within the Fee Methodology documents are in nominal dollars.

Metering Alternative Control Services (Type 5 & 6 Metering Services):

- Total forecast revenue to be earned from Metering Alternative Control Services in the forthcoming regulatory control period is disclosed in table 3.1 of the Reset RIN as 'Revenue from Metering Charges' (variable code DREV0109). In accordance with the Transitional Rules, Endeavour Energy are not separately charging for Metering Alternative Control Services in 2014/15. As a result, revenue from Metering Alternative Control Services in 2014/15 is nil. Note: figures reported for the forthcoming regulatory control period in table 3.1 are in real 2013/14 dollars.

- In addition, the AER can refer to the Metering Service Charge model attached to the Substantive Regulatory Proposal (Attachment 0.17) which discloses the forecast revenue to be earned from the provision of Metering Alternative Control Services. The proposed revenue to be earned is equal to the Total Recoverable Costs calculated in the Metering Service Charge model. However, it should be noted that the Metering Service Charge model does not reflect the Transitional Rules and assumes full recovery of Metering Alternative Control Services expenditure in 2014/15. All figures contained within the Metering Service Charge model are in nominal dollars.

Public Lighting Alternative Control Services:

- Refer to Attachment I to this RIN which presents the total revenue earned, and forecast to be earned, from Public Lighting Alternative Control Services. Note: figures reported for the forthcoming regulatory control period in worksheet 12.5 of Attachment I are in real 2013/14 dollars.

12.6 For metering and 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.

Metering Alternative Control Services (Type 5 & 6 Metering Services):

- Refer to the Metering Service Charge model, Attachment 0.17 to our regulatory proposal which identifies the forecast number of customers by Metering Alternative Control Service category for the forthcoming regulatory control period.

Public Lighting Alternative Control Services:

- The number of Public Lighting customers refers to the number of local councils or other authorities / companies which receive Street Light Use of System (SLUoS) services from Endeavour Energy. Refer to Attachment I, worksheet 12.6 which presents the number of Public Lighting Alternative Control Service customers for the current and forthcoming regulatory control period.

12.7(a) For each alternative control service listed in paragraphs 12, 13 and 14, provide the labour rate(s) used to calculate the charges for the current and forthcoming regulatory control periods specify the labour classification level used to provide the services e.g. outsourced or internally provided and labourer type; and

12.7(b) For each alternative control service listed in paragraphs 12, 13 and 14, provide the labour rate(s) used to calculate the charges for the current and forthcoming regulatory control periods list all direct costs, and their quantum, in the make-up of the labour rate(s).

Fee-Based & Quoted Alternative Control Services (Ancillary Network Services)

Refer to the Fee Methodology documents, Attachment 8.09 to our regulatory proposal for details in relation to how each Ancillary Network Service proposed fee was calculated, including current and forecast labour rates (direct costs only) and labour types/classification (if applicable to the development of the specific Ancillary Network Service fee). Worksheet 12.7 of Attachment I provides a summary of all the employees directly involved in the provision of one or more Ancillary Network Services, their labour rates and an explanation of what types of costs are included in the rates provided. These labour rates are used in the development of Ancillary Network Service expenditure forecasts for the forthcoming regulatory control period, and therefore impact proposed fees calculated for each Ancillary Network Service.

Metering Alternative Control Services (Type 5 & 6 Metering Services)

Refer to the Metering Service Charge model, Attachment 0.17 to our regulatory proposal for details in relation to how Metering Alternative Control Service fees were calculated. While labour rates for the forthcoming regulatory control period impact expenditure forecasts for Metering Alternative Control Services, and therefore in turn impacts total Metering Service recoverable costs, the proposed fees were not calculated based on a labour rate multiplied by hours to complete specific tasks. Rather, the Metering Service Charge model is based on the recovery of a pool of forecast expenditure, allocated to individual Metering Service categories. However, worksheet 12.7 of Attachment I provides a summary of all the employees directly involved in the provision of Metering Alternative Control Services, their labour rates and an explanation of what types of costs are included in the rates provided. These labour rates are used in the development of Metering Alternative Control Service expenditure forecasts for the forthcoming regulatory control period, and therefore impact proposed fees calculated for Metering Alternative Control Services.

Public Lighting Alternative Control Services

Refer to the Endeavour Energy Public Lighting model, Attachment 8.05 to our regulatory proposal for details in relation to how Public Lighting charges for the forthcoming regulatory control period were calculated. Worksheet 12.7 of Attachment I provides a summary of all the employees directly involved in the provision of Public Lighting Alternative Control Services, their labour rates and an explanation of what types of costs are included in the rates provided. These labour rates are used in the development of Public Lighting expenditure forecasts for the forthcoming regulatory control period, and therefore impact proposed Public Lighting charges calculated for Public Lighting Alternative Control Services.

The labour rate data provided in worksheet 12.7 relates to internal employees only. While contractors may assist Endeavour Energy in delivering some Alternative Control Services (i.e. Type 6 Scheduled Meter Reading), Endeavour Energy do not have any information in relation to the labour rates related to individuals who provide services under an external contract.

12.8 List each material category (e.g. meters, poles, brackets) required for the provision of alternative control services listed in the response to paragraphs 12, 13 and 14. Provide:

- (a) a description of each material category.**
- (b) the average unit costs for each material category.**
- (c) List all direct costs included in the unit costs.**

(d) Specify the calculation of the quantum of direct costs included in the unit cost of materials.

Fee-Based & Quoted Alternative Control Services (Ancillary Network Services)

Refer to Attachment I, worksheet 12.8(a) for a list of each Ancillary Network Service and the identification and description of the materials used in the provision of each service. In addition, the average unit costs in 2012/13 dollars for each material category is provided. These costs represent direct costs only (i.e. exclude overheads) and have been calculated based on actual costs to purchase these items in 2012/13.

Metering Alternative Control Services (Type 5 & 6 Metering Services)

The primary materials involved in the provision of Metering Alternative Control Services are meters and modems (for Type 5 meters with communications equipment installed). Refer to Attachment I, worksheet 12.8(b) for a list of the meters and modems used in the provision of Metering Alternative Control Services and their current unit rate / purchase price. These costs represent direct costs only (i.e. exclude overheads) and have been calculated based on actual costs to purchase these items.

Public Lighting Alternative Control Services

Refer to the Endeavour Energy Public Lighting model Attachment 8.05 to our regulatory proposal for a description of the primary materials used in the provision of Public Lighting Alternative Control Services, and their associated average unit rates, for the forthcoming regulatory control period. These costs represent direct costs only (i.e. exclude overheads) and have been calculated based on actual costs to purchase these items.

13. Fee Based and Quoted Alternative Control Services

13.1(a) 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 Endeavour Energy's annual tariff proposals. Specify if the charges are for fee based and/or quoted alternative control services.

Refer to the Fee Methodology documents, Attachment 8.09 to our regulatory proposal for a description of each Ancillary Network Service. Each Ancillary Network Service is comprised of several individual fee categories. Individual fee categories within each Ancillary Network Service are identified as either a fee-based service or a quoted service depending on the fee driver.

Refer to Attachment J, worksheet 13.1(a) which lists all Ancillary Network Services and their individual fee categories and identifies the fee driver and classification as either a fee-based service or a quoted service in accordance with the definitions provided in Appendix F of the Reset RIN.

13.1(b) 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 Endeavour Energy's annual tariff proposals. Explain the reasons for the different charge with reference to the costs incurred.

Refer to the Fee Methodology documents, Attachment 8.09 to our regulatory proposal for Endeavour Energy's workings with respect to the calculation of Ancillary Network Service charges. The methodology applied to calculate the proposed fees for each Ancillary Network Service, including the use of historic costs where available, is clearly outlined in the Fee Methodology documents.

13.1(c) 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 Endeavour Energy's annual tariff proposals. Explain the method used to set the different charge.

Refer to the Fee Methodology documents, Attachment 8.09 to our regulatory proposal for Endeavour Energy's workings with respect to the calculation of Ancillary Network Service charges. The methodology applied to calculate the proposed fees for each Ancillary Network Service is clearly outlined in the Fee Methodology documents.

13.1(d) 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 Endeavour Energy's annual tariff proposals. Provide the calculations underpinning the different charge.

Refer to the Fee Methodology documents, Attachment 8.09 to our regulatory proposal for Endeavour Energy's workings with respect to the calculation of Ancillary Network Service charges. The inputs, calculations and methodology applied to derive the proposed fees for each Ancillary Network Service are clearly disclosed in the Fee Methodology documents.

13.2(a) Identify the tasks involved in providing the service in regulatory templates 4.3 and 4.4. Map the class of labour required to provide the service listed in regulatory templates 4.3 and 4.4.

Refer to the Fee Methodology documents, Attachment 8.09 to our regulatory proposal for a description of each Ancillary Network Service (including the individual tasks involved). Each Ancillary Network Service is comprised of several individual fee categories. Individual fee categories within each Ancillary Network Service are identified as either a fee-based service or a quoted service depending on the fee driver.

Each Ancillary Network Service is comprised of several individual fee categories. Individual fee categories within each Ancillary Network Service are identified as either a fee-based service or a quoted service depending on the fee driver. Whilst there are several fee categories for each Ancillary Network Service (comprising either fee-based or quoted services), the type of labour involved in providing the service can be summarised at the Ancillary Network Service level (rather than the fee-based or quoted service level).

Refer to Attachment J, worksheet 13.2(a) which identifies the primary direct labour classes involved in the provision of each Ancillary Network Service (which includes all fee-based and quoted services).

13.2(b) Identify the tasks involved in providing the service in regulatory templates 4.3 and 4.4. The number of workers required to undertake the task and deliver the service.

Refer to the Fee Methodology documents, Attachment 8.09 to our regulatory proposal for Endeavour Energy's workings with respect to the calculation of Ancillary Network Service charges. The Fee Methodology documents include a calculation input worksheet which, for several fees, identifies the number of workers and average time required to undertake the task and delivery the service. In addition, several fees are charged on the basis of standard / average hours, which are also disclosed in the Fee Methodology documents. These standard / average hours provide an additional view of the resource requirement and time required to deliver the service.

It is noted however that some Ancillary Network Service fees were developed on the basis of historic total costs and/or are not charged on the basis of standard / average hours. As a result, in the development of proposed fees for these services, analysis was not performed to identify the number of workers or time required to undertake the task (as it was not appropriate to the particular fee). However, the inputs, calculations and methodology applied to derive the proposed fees for each Ancillary Network Service, and disclosed in the Fee Methodology documents, will provide information in relation to the resource requirement to deliver each service.

13.2(c) Identify the tasks involved in providing the service in regulatory templates 4.3 and 4.4. The average time required to complete the task and deliver the service.

Refer to the Fee Methodology documents, Attachment 8.09 to our regulatory proposal for Endeavour Energy's workings with respect to the calculation of Ancillary Network Service charges. The Fee Methodology documents include a calculation input worksheet which, for several fees, identifies the number of workers and average time required to undertake the task and delivery the service. In addition, several fees are charged on the basis of standard / average hours, which are also disclosed in the Fee Methodology documents. These standard / average hours provide an additional view of the resource requirement and time required to deliver the service.

It is noted however that some Ancillary Network Service fees were developed on the basis of historic total costs and/or are not charged on the basis of standard / average hours. As a result, in the development of proposed fees for these services, analysis was not performed to identify the number of workers or time required to undertake the task (as it was not appropriate to the particular fee). However, the inputs, calculations and methodology applied to derive the proposed fees for each Ancillary Network Service, and disclosed in the Fee Methodology documents, will provide information in relation to the resource requirement to deliver each service.

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

Each Ancillary Network Service is comprised of several individual fee categories. Individual fee categories within each Ancillary Network Service are identified as either a fee-based service or a quoted service depending on the fee driver. Whilst there are several fee categories for each Ancillary Network Service (comprising either fee-based or quoted services), the type of materials involved in providing the service can be summarised at the Ancillary Network Service level (rather than the fee-based or quoted service level) for all fees with the exception of Excluded Distribution Services.

Refer to Attachment J, worksheet 13.3 which lists each Ancillary Network Service and identifies the materials required to provide the service.

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

Question 13.4 refers to the charges related to fee-based and quoted alternative control services. Although Endeavour Energy currently levies charges for a number of these services, they are classified as standard control services in the current regulatory control period. These services are only classified as alternative control services from 2014/15 onwards (i.e. forthcoming regulatory control period).

Noting the above, question 13.4 only requires the disclosure of proposed charges for fee-based and quoted services for the forthcoming regulatory control period, as this is when they are classified as alternative control services. However, each of the Fee Methodology documents, Attachment 8.09 to our regulatory proposal, identifies current fees (if applicable) and proposed fees for each Ancillary Network Service.

14. Metering Alternative Control Services

14.1(a) For meter types 4, 5 and 6, for the current regulatory control period and forecast for the forthcoming regulatory control period, provide details of the direct materials and direct labour costs.

Refer to Attachment K, worksheet 14.1(a) for details of forecast direct materials and direct labour costs related to Metering Alternative Control Services for the forthcoming regulatory control period.

14.1(b) For meter types 4, 5 and 6, for the current regulatory control period and forecast for the forthcoming regulatory control period, provide details of the installation costs.

Refer to Attachment K, worksheet 14.1(b) for details of forecast installation costs related to Metering Alternative Control Services for the forthcoming regulatory control period.

14.1(c) For meter types 4, 5 and 6, for the current regulatory control period and forecast for the forthcoming regulatory control period, provide details of the meter purchase costs

Refer to Attachment K, worksheet 14.1(c) for details of forecast meter purchase costs related to Metering Alternative Control Services for the forthcoming regulatory control period.

14.1(d) For meter types 4, 5 and 6, for the current regulatory control period and forecast for the forthcoming regulatory control period, provide details of the volumes of work.

Refer to table 4.2.2 in the Reset RIN for volumes of Metering Alternative Control Service work related to individual metering service activities.

14.1(e) For meter types 4, 5 and 6, for the current regulatory control period and forecast for the forthcoming regulatory control period, provide details of the other costs associated with providing metering services.

Refer to Attachment K, worksheet 14.1(e) for details of forecast other costs related to Metering Alternative Control Services for the forthcoming regulatory control period.

14.1(f) For meter types 4, 5 and 6, for the current regulatory control period and forecast for the forthcoming regulatory control period, provide details of the type of meters installed and forecast to be installed, separately for new meters and for replacement meters.

For new meter installs refer to table 4.2.1. Note that for type 4 meters and type 6 CT meters Endeavour Energy would perform the new meter installations, while for type 6 direct connect meters ASPs would perform the new meter installations. This table provides the volume of installed meters.

For meter replacements refer to table 4.2.2 Volume Metrics sub categories Meter Replacement and Meter Maintenance. This table provides the volume of the associated service orders.

14.1(g) For meter types 4, 5 and 6, for the current regulatory control period and forecast for the forthcoming regulatory control period, provide details of the volume of meters by type set out in (f) and the revenue earned and forecast to be earned by each meter type.

Refer to table 4.2.1 in the Reset RIN for the volume of meters / meter population by type for each year in the forthcoming regulatory control period. The revenue forecast to be earned during the forthcoming regulatory control period from the provision of Metering Alternative Control Services is provided in Attachment K, worksheet 14.1(g). Metering Alternative Control Service charges are levied based on the type of metering service received by the customer (i.e. basis, time-of-use, controlled load, solar etc), rather than the type of meter installed or the individual metering

activity/service performed by Endeavour Energy. As a result, the forecast revenue provided in Attachment K, worksheet 14.1(g) is split by tariff category rather than by meter type or specific metering activity/service. Refer to the Metering Service Charge model attached to the Substantive Regulatory Proposal for details in relation to the calculation of Metering Alternative Control Service charges and forecast revenue (Attachment 0.17).

14.1(h) For meter types 4, 5 and 6, for the current regulatory control period and forecast for the forthcoming regulatory control period, provide details of the total operating and maintenance costs incurred, and forecast to be incurred, for metering services.

Refer to table 4.2.2 in the Reset RIN for operating and maintenance costs forecast to be incurred for Metering Alternative Control Services for the forthcoming regulatory control period (in real 2013/14 dollars). Operating and maintenance costs include all categories in table 4.2.2 except for Meter Purchase and Meter Replacements (these represent capital expenditure).

14.2(a) For metering works, for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period, provide a description of the type of work undertaken (e.g. meter reconfiguration, special meter read) including a description of the activities undertaken to provide the service.

Refer to Attachment K, worksheet 14.2(a) for a description of the type of work undertaken in relation to Metering Alternative Control Services.

14.2(b) For metering works, for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period, provide a description of the labour costs involved in providing the service, including any overheads.

The labour costs involved in providing Metering Alternative Control Service include Field Staff, Back office Administration and Overhead Staff such as Management, Finance, HR, Legal and Procurement.

14.2(c) For metering works, for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period, provide a description of any materials costs involved in providing the service

The primary material costs involved in providing Metering Alternative Control Services includes meters and modems.

14.2(d) For metering works, for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period, provide a description of the number (volume) of services provided and associated assumptions on which the volume of service was derived or estimated.

Refer to table 4.2.2 in the Reset RIN for volumes of Metering Alternative Control Service work related to individual metering service activities. These volumes were estimated based on the following methodology.

- Determining historical meter type is based on the meter type ratio from the Cost Metric Volume table.
- Type 4 meters as requested are franchise market meters with comms. Endeavour Energy does not have any Type 5 manual read meters, all meters in the Type 5 energy volume range are Type 4 comms franchise meters.
- The volume of metering services was obtained from our metering work management system, BANNER, for the reporting period 2008/2009 to 2012/2013. Forecasted volumes are based on an estimate.

- Total metering services volume for the reporting period 2008/2009 to 2012/2013 is based on actual volumes from BANNER. Forecasted total volumes are extrapolation based on either a customer growth factor, forecasted meter population obtained from the Descriptor Metric table or averages.
- Determining historical meter type is based on actual data for the meter purchase subcategory and is estimated for all other subcategories.
- The customer growth factor is based on actual NMIs at the end of each financial year
- Metering services volumes for 2013/2014 is based on the average of the historical reporting periods.
- For the meter purchase subcategory the historical metering services is based on when the meter is installed.
- For the meter purchase subcategory the total metering services volume forecast is based on the forecasted meter population obtained from the Descriptor Metric table. The type 4 forecast is based on the energy threshold management procedure which identifies accumulation type 6 meters that needs to have interval meters installed.
- For the meter maintenance subcategory the total metering services volume forecast is based on the customer growth factor. The type 4 forecast is based on the energy threshold management procedure which identifies accumulation type 6 meters that needs to have interval meters installed.
- For the meter replacement subcategory based on our MAMP meter replacement program. The meter type is determined by the population ratio.
- For the special meter reading subcategory the total metering services volume forecast is based on the customer growth factor and all assigned to type 4 because these meters were previously manually read and required special meter readings. The forecast is zero because Endeavour Energy does not have any Type 5 manual read meters, all meters in the Type 5 energy volume range are Type 4 comms franchise meters.
- For all other subcategories the total metering services volume forecast is based on the customer growth factor. The meter type is determined by the population ratio.

14.2(e) For metering works, for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period, provide a description of the charge per service.

Refer to the Metering Service Charge model, Attachment 0.17 to our regulatory proposal which calculates the charge per metering service for each year in the forthcoming regulatory control period.

14.2(f) For metering works, for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period, provide a description of the revenue earned by each service.

The revenue forecast to be earned during the forthcoming regulatory control period from the provision of Metering Alternative Control Services is provided in Attachment K, worksheet 14.1(g). Metering Alternative Control Service charges are levied based on the type of metering service received by the customer (i.e. basis, time-of-use, controlled load, solar etc), rather than the type of meter installed or the individual metering activity/service performed by Endeavour Energy. As a result, the forecast revenue provided in worksheet 14.1(g) is split by tariff category rather than by meter type or specific metering activity/service. Refer to the Metering Service Charge model attached to the Substantive Regulatory Proposal for details in relation to the calculation of Metering Alternative Control Service charges and forecast revenue.

15. Public Lighting Alternative Control Services

15.1 Specify which items are capital expenditure and operational expenditure for each year of the current regulatory control period and forecasts for the forthcoming regulatory control period.

CAPEX

1. All expense under Non-Contestable Street Lighting projects.
2. Gift tax paid on Contestable Street Lighting Projects.
3. Replacement of condemned column/bracket.
4. Replacement of a column during an impact.
5. Replacement of a luminaire as an improvement to the old luminaire eg 80W to 42WCFL.

OPEX

1. Condition based maintenance.
2. Fault and emergency. Outage Management System calls.
3. Routine column inspection / patrol.
4. Bulk lamp replacement.
5. Replacement of a like for like luminaire.

15.2 Provide unit costs for the current regulatory control period and forecast for the forthcoming regulatory control period for: Luminaires, Dedicated street lighting poles, Brackets, Lamps, Photoelectric cells, Labour rate (per hour) and Miscellaneous materials

Price list is Attachment 0.16 to our regulatory proposal. Additionally, refer to Attachment L to this Reset RIN.

For street lighting the EWP lease rate is \$71,500 / year per EWP. The forecast for forthcoming regulatory period is expected to be at the CPI increase level. This is considered at 2.5% each year to 2018/19.

Labour rates for each year of the current and forecast regulatory control period are provided in Attachment I, worksheet 12.7 to this RIN.

Prorata projection for Traffic Management for 2013/14 is expected to be \$102,000. (July 2013 to February 2014 Traffic Management = \$68,265).

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

20 years for all types.

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

Lamps: 3 years.

Photo cell: No bulk change plan is in place.

D2 type PCell: Life Expectancy 10 years (4000 cycles)

NEMA type PE cell: 10 years

15.5 Provide details of the average replacement age of each type of luminaire.

Though the average replacement age is not available, it is assumed to be 20 years.

15.6 Provide the number of luminaires, by type.

List provided as Attachment M to this Reset RIN.

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

Indicative usage of each street light asset is given in Annexure 1. This includes both, the new installations and replacements as a consequence of a maintenance event. Streetlight Assets increase at an annual rate of 2.5% per annum (Public Lighting Luminaires in 2006= 166,479 ; Public Lighting Luminaires in 2013=195,630 showing an average growth of 2.5% per year). This is based on the past six years data. Future projections are anticipated at 2.5% each year (Attachment N to this Reset RIN).

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

Other direct or indirect costs which are incurred at regular interval are listed below:

1. Traffic management during installation / repair.
2. Various reports prepared for councils (5 types), two council meetings each year, regular feedback to councils on lighting issues. (Total 900 engineer hours per year).
3. Field surveys and audits. 300 man hours per year.

15.9 Provide models and/or modelling that underpins proposed charges for the forthcoming regulatory control period and the reasons for the assumptions behind those forecasts.

This is addressed in the pricing model, Attachment 8.05 to our regulatory proposal.

16. Economic Benchmarking

16.1 Complete the Economic Benchmarking regulatory templates (3.1 to 3.7) in accordance with the instructions and definitions for variables within: Economic Benchmarking RIN for distribution network service providers Instructions and Definitions Endeavour Energy November 2013 and the instructions in paragraphs 16.1 to 16.4.

The Economic Benchmarking regulatory templates (3.1 to 3.7) have been completed in accordance with the instructions and definitions for variables within the Economic Benchmarking RIN for distribution network service providers Instructions and Definitions Endeavour Energy November 2013 and the instructions in paragraphs 16.1 to 16.4.

16.2(a) The forecast revenue groupings in tables 3.1.1 and 3.1.2 may be developed by trending forward actual historical revenue groupings in previous regulatory years. However: Total revenues must equal total forecast revenues as proposed by Endeavour Energy in its revenue proposal, and Revenue groupings must reflect Endeavour Energy's forecast demand for its services in the Forthcoming Regulatory Control Period in its revenue proposal.

The forecast revenue groupings in tables 3.1.1 and 3.1.2 equal the total forecast revenues as proposed by Endeavour Energy in its regulatory proposal and the revenue groupings reflect Endeavour Energy's forecast demand for services in the forthcoming regulatory control period.

16.2(b) 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).

The definition of a tree has been 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).

16.2(c) In calculating responses to the variables DOEF0202 to DOEF0205, spans in the network service area where Endeavour Energy is not responsible for the vegetation management associated with the span are not to be counted.

In calculating response to the variables DOEF0202 to DOEF0205, spans where Endeavour Energy is not responsible for the vegetation management associated with the span have not been counted.

16.2(d) "Total number of spans" (DOEF0205) does not include service line spans.

It is confirmed that "Total number of spans" (DOEF0205) does not include service line spans.

16.2(e) Endeavour Energy must report the route line length of feeders classified as either short rural or long rural divided by the total route feeder line length (this is the total feeder route line length for all CBD, urban, short rural and long rural feeders) against "Rural proportion" (DOEF0201).

It is confirmed that Endeavour Energy has reported the route line length of feeders classified as either short rural or long rural divided by the total route feeder line length against "Rural proportion" (DOEF0201).

16.2(f) For the purposes of calculating the "Route line length" variable (DOEF0301) or other variables measured in terms of route line length: (i) The length of service lines are

not to be counted (ii) the length of a span that shares multiple voltage levels is only to be counted once (iii) the lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately

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

- i. The length of service lines are not counted;
- ii. The length of a span that shares multiple voltage levels is only counted once; and
- iii. The lengths of two sets of lines that run on different sets of poles (or towers) but share the same easement are counted separately.

In relation to Item (iii) geospatial buffers of 0.1metre, 0.5metres and 10% were used in gathering the spatial data, which meant a minor possibility of two sets of lines in the same easement being captured once (rather than separately). However, spot checks of results indicated this was not an issue, and generally ORB spatial capture standards for offsets, indicate this should not be an issue.

16.3 All forecast variables in the Economic Benchmarking regulatory templates must align with those in Endeavour Energy’s regulatory proposal. For the avoidance of doubt this includes forecast: opex and capex; Maximum demand, customer numbers, Energy delivery; Revenues; quality of services variables including SAIDI, SAIFI and MAIFI; and Quantities of physical assets.

All forecast variables in the Economic Benchmarking regulatory templates align with those in Endeavour Energy’s regulatory proposal.

16.4 RAB asset financial data in the Assets (RAB) regulatory template must reconcile to that in Endeavour Energy’s PTRM and RFM.

RAB asset financial data in the Assets (RAB) regulatory template reconciles to that in Endeavour Energy’s PTRM and RFM.

17. Provisions

17.1 For each of Endeavour Energy's provisions, provide the information required in regulatory template 2.13 in accordance with: (a) regulatory template 2.1, (b) Australian Accounting Standard AASB 137 Provisions, Contingent Liabilities and Contingent Assets.

All information provided has been completed in the required format in the regulatory template and complies with Australian Accounting Standard *AASB 137 Provisions, Contingent Liabilities and Contingent Assets*.

17.2 If, in a given year, there is an increase in the amount of a provision, provide reasons for this increase, including:

(a) the expected timing of any resulting outflows of economic benefits;

Please refer to comments included in the regulatory template Table 2.13.1 – Changes in total provisions and the basis of preparation document in regards to details of movements in provisions.

(b) an explanation of the uncertainties about the amounts or timing of the outflows;

Please refer to comments included in the regulatory template Table 2.13.1 – Changes in total provisions and the basis of preparation document in regards to details of movements in provisions.

(c) supporting consultant's advice, including actuarial reports; and

(d) if there is no supporting consultant's advice, the process and assumptions Endeavour Energy used in determining the increase in the provision.

Please refer to comments included in the regulatory template Table 2.13.1 – Changes in total provisions and the basis of preparation document in regards to details of movements in provisions. Refer to Attachments O and P to this RIN for the relevant actuarial reports.

17.3 Provide the allocation of the movement in total provisions in regulatory template 2.13, Table 2.13.2 to:

(a) opex;

(b) as-incurred capex by roll forward model asset class; and

(c) other, where the movement in the provision is neither capex nor opex.

As completed in Table 2.13.2 – Allocation of movement in total provisions, all movements are allocated to opex, with the exception of Defined Benefits Superannuation actuarial gains and losses which are allocated directly to Retained Earnings.

17.4 Identify and explain any assumptions applied for the allocation of asset class provided under paragraphs 17.3(b).

As completed in Table 2.13.2 – Allocation of movement in total provisions, all movements are allocated to opex, with the exception of Defined Benefits Superannuation actuarial gains and losses which are allocated directly to Retained Earnings.

18. Forecast Price Changes

18.1 Provide, in regulatory template 2.14, the labour and material price changes assumed by Endeavour Energy in estimating Endeavour Energy's forecast capex proposal and the forecast opex proposal. All price changes must be expressed in percentage year on year real terms.

Endeavour Energy has provided the labour and material price changes assumed by Endeavour Energy in estimating Endeavour Energy's forecast capex and opex proposals in regulatory template 2.14. Regulatory template 2.14 is part of the Microsoft Excel Workbooks at Attachments RIN.1-3

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

Endeavour Energy have considered the real materials price changes developed by CEG that are based on most recently available market data and economic analysis and detailed in Attachments 0.04, 0.05 and 5.20 to our regulatory proposal. We have not included the impact of these forecast prices changes in our capex or opex forecasts.

18.2(b) Provide: in relation to labour escalators, a copy of the current Enterprise Bargaining Agreement or equivalent agreement.

A copy of the current Enterprise Bargaining Agreement is provided at Attachment Q to this Reset RIN.

18.2(c) Provide: evidence that the forecast price changes accurately explain the change in the price of goods and services purchased by Endeavour Energy, including evidence that any materials price forecasting method explains the price of materials previously purchased by Endeavour Energy.

Endeavour Energy is exposed to the real changes in commodity prices through contracts that it establishes for major items of equipment such as transformers, switchgear, cables and conductor. Attachment R to this Reset RIN shows an example of a contract price variation schedule that applies to our contract for the supply of power transformers that demonstrates how commodity price changes are included in the cost of transformers. Price changes are assessed on a regular basis by reference to relevant indices and incorporated via the formula shown in this schedule. Attachment S provides a summary of contract price variations due to a variety of factors including commodity price changes.

18.3(a) In Endeavour Energy's Basis of Preparation explain the methodology underlying the calculation of each price change, including sources, data conversions, the operation of any models provided under paragraph 18.2(a), and the use of any assumptions, such as lags or productivity gains.

Endeavour Energy has not applied any materials price changes to its expenditure forecasts. For details of the advice received however, refer to Attachments 0.04, 0.05 and 5.20 to our regulatory proposal.

18.3(b) Explain whether the same price changes have been used in developing both the forecast capex proposal and forecast opex proposal.

Endeavour Energy have only applied real changes in the price of labour in the development of its expenditure forecasts and have not applied any forecast changes in materials prices. The same price changes have been applied to both our capex and opex forecasts.

18.3(c) Explain if the response to paragraph 18.3 is negative, why it is appropriate for different expenditure escalators to apply.

The same cost escalators have been applied to both our capex and opex forecasts.

18.4 If an agreement provided in response to paragraph 18.2(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 Enterprise Bargaining Agreement provided in response to paragraph 18.2(b) has a nominal expiry date of 24 December 2014. Endeavour Energy expects to commence negotiations on a new Enterprise Bargaining Agreement on or around the end of June 2014 and expects negotiations to be finalised by 24 December 2014.

19. Related Party Transactions

19.1 Identify and describe all other entities which are a Related Party to Endeavour Energy and contribute to the provision of distribution services or have the capacity to determine the outcome of decisions about Endeavour Energy's financial and operating policies.

Endeavour Energy, Ausgrid and Essential Energy operate as separate legal entities but are managed by a joint Board of Directors and common Chief Executive Officer (CEO). The three network companies operate under a shared Group management model known as Networks NSW.

Endeavour Energy owns 33.3% of the shares in Networks NSW Pty Limited ACN 159 132 171. Each of Ausgrid and Essential Energy also owns 33.3% of the shares in Networks NSW Pty Limited. None of Ausgrid, Endeavour Energy and Essential Energy controls Networks NSW Pty Limited, but arguably each of them would be in a position to exert "significant influence" over Networks NSW Pty Limited for the purposes of the definition of "related party" by virtue of those 33.3% shareholdings.

Networks NSW Pty Limited performs limited functions as the agent of an unincorporated procurement joint venture between Ausgrid, Endeavour Energy and Essential Energy and does not contribute to the provision of distribution services for the purposes of question 19.1(a).

19.2 Provide a diagram of the organisational structure depicting the relationships between all the entities identified in the response to paragraph 19.1.

There are no related parties identified in 19.1. However, a diagram of the organisational structure is provided at Attachment T to this Reset RIN in response to paragraph 30.1 (a).

19.3(a) Identify all arrangements or contracts between Endeavour Energy and any of the other entities identified in the response to paragraph 19.1 which relate directly or indirectly to the provision of distribution services.

There are no related parties identified in 19.1 which relate to the provision of distribution services.

19.3(b) Identify the service or services the subject of each arrangement or contract.

There are no related parties identified in 19.1 which relate to the provision of distribution services.

19.4(a) For each service identified in the response to paragraph 19.1 provide a description of the process used to procure the service and supporting documentation including, but not limited to, requests for tender, tender submissions, internal committee papers evaluating the tenders, contracts between Endeavour Energy and the relevant provider.

There are no arrangements or contracts between Endeavour Energy and any of the other entities identified in the response to paragraph 19.1 which relate directly or indirectly to the provision of distribution services by Endeavour Energy.

19.4(b)(i) For each service identified in the response to paragraph 19.1 explain why that service is the subject of an arrangement or contract (i.e. why it is outsourced) instead of being undertaken by Endeavour Energy itself.

There are no arrangements or contracts between Endeavour Energy and any of the other entities identified in the response to paragraph 19.1 which relate directly or indirectly to the provision of distribution services by Endeavour Energy.

19.4(b)(ii) For each service identified in the response to paragraph 19.1 explain whether the services procured were provided under a standalone contract or provided as part of a broader operational agreement (or similar).

There are no arrangements or contracts between Endeavour Energy and any of the other entities identified in the response to paragraph 19.1 which relate directly or indirectly to the provision of distribution services by Endeavour Energy.

19.4(b)(iii) For each service identified in the response to paragraph 19.1 explain whether the services were procured on a genuinely competitive basis and if not, why.

There are no arrangements or contracts between Endeavour Energy and any of the other entities identified in the response to paragraph 19.1 which relate directly or indirectly to the provision of distribution services by Endeavour Energy.

19.4(b)(iv) For each service identified in the response to paragraph 19.1 explain whether the service (or any component thereof) was further outsourced to another provider.

There are no arrangements or contracts between Endeavour Energy and any of the other entities identified in the response to paragraph 19.1 which relate directly or indirectly to the provision of distribution services Endeavour Energy.

20. Proposed Contingent Projects

20.1(a) For each contingent project proposed in the regulatory proposal, provide a description of the proposed contingent project, including reasons why Endeavour Energy considers the project should be accepted as a contingent project for the forthcoming regulatory control period.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.1(b) For each contingent project proposed in the regulatory proposal, provide the proposed contingent capital expenditure which Endeavour Energy considers is reasonably required for the purpose of undertaking the proposed contingent project.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.1(c) For each contingent project proposed in the regulatory proposal, provide the methodology used for developing that forecast and the key assumptions that underlie it.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.1(d) For each contingent project proposed in the regulatory proposal, provide 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.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.1(e)(i) For each contingent project proposed in the regulatory proposal, provide a demonstration that the proposed contingent capital expenditure for each proposed contingent project is not included (either in part or in whole) in Endeavour Energy's proposed total forecast capital expenditure for the forthcoming regulatory control period.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.1(e)(ii) For each contingent project proposed in the regulatory proposal, provide a demonstration that the proposed contingent capital expenditure for each proposed contingent project reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors, in the context of the proposed contingent project.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.1(e)(iii) For each contingent project proposed in the regulatory proposal, provide a demonstration that the proposed contingent capital expenditure for each proposed contingent project exceeds either \$30 million or 5 per cent of Endeavour Energy's proposed annual revenue requirement for the first year of the forthcoming regulatory control period, whichever is the larger amount.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.1(f) For each contingent project proposed in the regulatory proposal, provide the proposed trigger events relating to the proposed contingent project.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.2(a) For each proposed trigger event relating to the proposed contingent project referred to in 20.1(f), demonstrate the proposed trigger event is reasonably specific and capable of objective verification.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.2(b) For each proposed trigger event relating to the proposed contingent project referred to in 20.1(f), demonstrate the occurrence of the proposed trigger event makes the undertaking of the proposed contingent project reasonably necessary in order to achieve any of the capital expenditure objectives.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.2(c) For each proposed trigger event relating to the proposed contingent project referred to in 20.1(f), demonstrate the proposed trigger event generates increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the distribution network as a whole.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.2(d) For each proposed trigger event relating to the proposed contingent project referred to in 20.1(f), demonstrate 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.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.2(e) For each proposed trigger event relating to the proposed contingent project referred to in 20.1(f), demonstrate the proposed trigger event is a condition or event, the occurrence of which is probable during forthcoming regulatory control period, but the inclusion of capital expenditure in relation to the proposed trigger event under clause 6.5.7 of the NER is not appropriate because: 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 the costs associated with the event or condition are not sufficiently certain.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

20.3 Provide a summary of Endeavour Energy's proposed contingent projects for the forthcoming regulatory control period including the proposed contingent capital expenditure and trigger events for each proposed contingent project in the regulatory template 7.2.

Endeavour Energy is not proposing any contingent projects in the regulatory proposal.

21. Non-Network Alternatives

21.1 Identify the Policies and Strategies and Procedures which relate to the selection of efficient non-network solutions.

A common Networks NSW Demand Management Policy has been developed to provide a consistent approach to investigating, evaluating and implementing non-network options. The policy also covers the development of new technologies and programs for demand management to ensure efficiencies are delivered to energy users.

The Endeavour Energy Major Project Formulation and Approval Procedure GAM0035 (Attachment 5.14 to our regulatory proposal), ensures that demand management investigations are conducted early in the network options investigation process and that sufficient time is allowed to implement feasible non-network alternatives.

The Endeavour Energy Demand Side Management Program Development procedure NCP2101 also outlines the process followed to identify, investigate and implement non-network options. This procedure will also be aligned across Networks NSW to ensure efficiencies are gained in identifying the most cost effective demand management option.

In consulting the interested parties and requesting submissions for non-network options Endeavour Energy follows internal procurement policy and procedures.

21.2 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.

As described above, Endeavour Energy follows the National Electricity Rules (NER) Chapter 5 Part B, Network Expansion and Planning when investigating all credible options to address a network limitation (refer to Attachment 5.14 to our proposal - GAM0035). The planning process includes an annual review of the network using the latest demand forecast. All previously known network limitations are verified and any new limitations identified. All network limitations are screened for non-network options and if feasible a consultation process is initiated to identify all cost-effective non-network options. All networks limitations where investigations are to be conducted are summarised in the Attachment 5.16 to our proposal, the Distribution Annual Planning Report (DAPR).

Endeavour Energy engages all interested parties and stakeholders via the consultation process as stipulated in the NER and procedure NCP2101. This procedure is currently being reviewed to ensure alignment across NNSW. Endeavour Energy is the facilitator of this project.

21.3(a) Identify each non-network Project that Endeavour Energy has commenced during the Current Regulatory Control Period.

Listed below are the non-network projects implemented during the current regulatory control period.

Non-network Projects Implemented – 2009/10 to 2013-14

Project Name	Year Commenced	Program Duration	Network Project Deferred	Network Project Estimated Cost
Granville	2010	1	Rebuild Granville ZS	\$32m

Rooty Hill	2010	2	Build Nth Glendenning ZS	\$23m
Arndell Park	2011	1	Build Huntingwood ZS	\$28m
Mamre	2012	2	Augment Mamre ZS	\$6m
Eschol Park	2012	2	Build Eschol Park ZS	\$20.5m
Westmead Extension	2012	1	Augment Westmead ZS	\$7.2m

21.3(b) Identify each non-network Project that Endeavour Energy has selected to commence during, or will continue into, the Forthcoming regulatory control period.

Listed below are the non-network projects that will be operational or investigated for feasibility during the next regulatory control period.

Non-network Projects Operational/Planned - 2014/15 to 2018-19

Project Name	Status	Project Timing	Network Project Deferred
Eschol Park	Current	Commenced in 2012 planned to end March 2015	Build Eschol Park ZS
Southern Nepean 66kV Network	Feasible	Possible implementation July 2015	Build 66kV feeder
Feeder 808-Springwood ZS	Investigation	If feasible implemented prior to summer 2015/16	Augment feeder 808
Penrith 11kV ZS	Investigation	Dependant on load growth	Augment Penrith 11kV ZS
Riverstone 11kV ZS	Investigation	Dependant on load growth	Augment Riverstone ZS
Culburra 11kV ZS	Investigation	Dependant on load growth	Augment Culburra ZS
Feeder 500, 528 – Anzac Village ZS	Investigation	Dependant on load growth	Augment 33kV feeders
Feeder 490, 491 - St Marys ZS	Investigation	Dependant on load growth	Augment 33kV feeders
Cranebrook ZS	Investigation	Dependant on load growth	Augment ZS and 33kV feeders

21.4 For each non-network Project identified in the response to paragraph 21.3, provide a description, including cost and location.

Listed below are the details for each non-network identified in 21.3.

Non-network Projects Details

Project Name	Program Type	Program Cost	Demand Reduction Target	Net Program Projected Savings
Granville	Industrial Commercial	\$620,000	3.2 MVA	\$347,000
Rooty Hill	Industrial Commercial Residential	\$947,000	5.0 MVA	\$1,143,000
Arndell Park	Industrial Commercial	\$1,093,000	6.9 MVA	\$1,058,000
Mamre	Industrial Commercial	\$819,000	8.8 MVA	\$171,000
Eschol Park	Industrial Commercial	\$1,753,000	11.4 MVA	\$1,366,000
Westmead Extension	Major Customer	\$498,000	2.0 MVA	\$233,000
Southern Nepean 66kV Network	PFC-Embedded Generation	\$1,980,000	13.3 MVA	\$1,030,000
Feeder 808-Springwood ZS	Residential	To be determined		
Penrith 11kV ZS	Industrial Commercial Residential	To be determined		

Riverstone 11kV ZS	Industrial Commercial Residential	To be determined
Culburra 11kV ZS	Residential	To be determined
Feeder 500, 528 – Anzac Village ZS	Residential	To be determined
Feeder 490, 491 - St Marys ZS	Industrial Commercial Residential	To be determined
Feeder 451, 459 – Cranebrook ZS	Industrial Commercial Residential	To be determined

21.5 Provide, for each year of the current regulatory period, and for the forthcoming regulatory control period, details of each payment made, or expected to be made, by Endeavour Energy to an Embedded Generator in reflection any costs avoided by deferring augmentation of: Endeavour Energy's distribution network; or the relevant transmission network.

Endeavour Energy has multiple load curtailment agreements with customers to reduce load on request. These are active agreements mainly in the current regulatory period. There is one agreement involving an embedded generator that will extend into the first year of the next regulatory period. As non-network programs are investigated and submissions received it is likely that additional embedded generation proposals agreements will be developed.



22. Efficiency Benefit Sharing Scheme

22.1(a) To calculate the carryover amounts that arise from applying the efficiency benefit sharing scheme during Endeavour Energy's current regulatory control period provide the forecast and actual operating expenditure amounts in regulatory template 7.5.

Endeavour Energy has provided the forecast and actual operating expenditure amounts in regulatory template 7.5. Regulatory template 7.5 is part of the Microsoft Excel Workbooks at Attachments RIN.1-3

22.1(b) To calculate the carryover amounts that arise from applying the efficiency benefit sharing scheme during Endeavour Energy's current regulatory control period identify all changes to Endeavour Energy's Capitalisation Policy during the current regulatory control period.

There has been one change to Endeavour Energy's capitalisation policy during the current regulatory control period, that being the change from purchasing vehicles such as passenger vehicles to a leasing arrangement. This change has been implemented gradually over the current regulatory control period as previously purchased vehicles are replaced with leased vehicles in line with the Endeavour Energy replacement cycle.

22.2(a) For each change identified in the response to paragraph 22.1(b) state, if any, the financial impact of the change.

As a result of the change the capital expenditure incurred by Endeavour Energy for motor vehicles has been lower than forecast at the commencement of the current regulatory control period. Although not 100% correlated to the change in passenger vehicle acquisition approach the overall decrease in motor vehicle capex during the current regulatory period is set out in the table below.

	2009/10	2010/11	2011/12	2012/13
Change in motor vehicle capex compared to forecast	-\$17,754,545	-\$3,205,429	-\$9,885,684	-\$19,883,806

22.2(b) For each change identified in the response to paragraph 22.1(b) state the reasons for the change.

Endeavour Energy undertook a review of the comparative costs of purchasing motor vehicles including all related costs compared to the costs of leasing motor vehicles. The result of the analysis demonstrated that for passenger and some light commercial vehicles the costs of leasing vehicles were lower in NPV terms over the expected useful life of the vehicles compared to purchasing vehicles.

Endeavour Energy therefore adopted the lower NPV solution for obtaining the same service potential with the savings included in our forecast capital and operating programs for the next regulatory control period.

22.2(c) For each change identified in the response to paragraph 22.1(b) explain the effect of the change, if any, on the forecast operating expenditure for each year of Endeavour Energy's current regulatory control period.

Endeavour Energy did not undertake a revised forecast of its standard control services operating expenditure over the current regulatory period.

22.2(d) For each change identified in the response to paragraph 22.1(b) explain the effect of the change, if any, on the actual operating expenditure for each year of Endeavour Energy's current regulatory control period.

The increase in the reported actual operating expenditures for the current regulatory period as set out in the annual regulatory reporting information is provided in the table below. All amounts are nominal dollars.

	2009/10	2010/11	2011/12	2012/13
Opex impact of change in motor vehicle sourcing strategy	41,843	542,274	1,341,581	2,843,904

22.3(a) For the purposes of applying the efficiency benefit sharing scheme identify all cost categories proposed to be excluded from the operation of the efficiency benefit sharing scheme.

Endeavour Energy is not proposing to exclude any cost categories from the operation of the efficiency benefit sharing scheme.

22.3(b) For the purposes of applying the efficiency benefit sharing scheme explain for each cost category identified in the response to paragraph 22.3(a) the reasons for the proposed exclusion.

Endeavour Energy is not proposing to exclude any cost categories from the operation of the efficiency benefit sharing scheme.

23. Service and Quality

23.1(a) Provide Endeavour Energy's detailed methodology for calculating the following parameters used in the Service Target Performance Incentive Scheme (STPIS) - the SAIDI, SAIFI and MAIFI targets for each supply reliability area. Note: All calculations must be made in accordance with the STPIS and using data which complies with the STPIS definitions.

Please see Attachment 0.14 to our regulatory proposal.

23.1(b) Provide Endeavour Energy's detailed methodology for calculating the following parameters used in the Service Target Performance Incentive Scheme (STPIS) - the customer service parameters and targets. Note: All calculations must be made in accordance with the STPIS and using data which complies with the STPIS definitions.

Annual data up to FY 12/13 is actual data. The data for the FY 13/14 is based on actual data from July 2013 to March 2014, and estimated data from April 2014 to June 2014.

The estimated call data for FY 13/14 assumes that the last three months of that reporting year will have average call volume of the previous 12 months.

The estimated '% calls answered in 30 sec' data for FY 13/14 assumes that the last three months of that reporting year will have average '% calls answered in 30 sec' equal to that of the months from July 2013 to March 2013.

Estimated call data for periods 2014-15 to 2018-19 has been based on the average of actual data from February 2013 to March 2014. February 2013 was chosen as the start date for the estimated data as this was the first month that Endeavour Energy 'Retail Separation'. As such this period of data presents a more realistic picture of the current and future customer service environment.

Estimated '% calls answered in 30 sec' data for periods 2014-15 to 2018-19 has been based on the average of actual data from February 2013 to Mar 2014. Reasons are as stated above.

Please see Attachment 0.14 to our regulatory proposal.

23.1(c) Provide Endeavour Energy's detailed methodology for calculating the following parameters used in the Service Target Performance Incentive Scheme (STPIS) -daily SAIDI, SAIFI, MAIFI and customer service performance derived from the individual interruption data under 23.2. Note: All calculations must be made in accordance with the STPIS and using data which complies with the STPIS definitions.

Please see Attachment 0.14 to our regulatory proposal.

23.1(d) Provide Endeavour Energy's detailed methodology for calculating the following parameters used in the Service Target Performance Incentive Scheme (STPIS) - the MED threshold derived from the daily SAIDI data. Note: All calculations must be made in accordance with the STPIS and using data which complies with the STPIS definitions.

Please see Attachment 0.14 to our regulatory proposal.

23.1(e) Provide Endeavour Energy's detailed methodology for calculating the following parameters used in the Service Target Performance Incentive Scheme (STPIS) - 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.

Please see Attachment 0.14 to our regulatory proposal.

23.2 Details of all interruptions that occurred in the 2008-09 to 2012-13 regulatory years must be provided in regulatory template 6.3 and in accordance with the definitions contained in this notice and definitions and the STPIS.

Details of all interruptions that occurred in the 2008-09 to 2012-13 regulatory years have been provided in regulatory template 6.3 and in accordance with the definitions contained in this notice and definitions and the STPIS. Regulatory template 6.3 is part of the Microsoft Excel Workbooks at Attachments RIN1-3.

23.3(a) If Endeavour Energy proposes adjustments to the STPIS targets away from those based upon raw historical data Endeavour Energy must provide the reasons for the change.

Endeavour Energy is proposing adjustments to the STPIS target for calls answered within 30 seconds away from that based upon raw historical data.

The reason that Endeavour Energy has not applied the average of the last 5 years as a target for '% calls answered in 30 sec', is that our business model is significantly different now, compared to previous years. Prior to 'Retail Separation' in February 2013, the Endeavour Energy Call Centre's had significantly more staff that were multi skilled, taking both retail and network related calls. The target suggested by Endeavour Energy reflects the post retail separation model, and Endeavour's focus on reducing costs to the customer while continuing to maintain a sustainable level of service.

See also Attachment 0.14 to our regulatory proposal.

23.3(b) If Endeavour Energy proposes adjustments to the STPIS targets away from those based upon raw historical data Endeavour Energy must provide the quantum of the adjustment, and the effect of the adjustment on the targets for each of the supply reliability areas.

The average of calls answered in 30 seconds in the five years from FY08/09 to FY12/13 is 88%. Endeavour Energy requests an adjustment to the target that would see it reduced to 75%. There is no anticipated impact to supply reliability as a result of this target adjustment.

See also Attachment 0.14 to our regulatory proposal.

23.3(c) If Endeavour Energy proposes adjustments to the STPIS targets away from those based upon raw historical data Endeavour Energy must provide the method, basis and empirical data used as justification for the adjustment.

The method that Endeavour Energy has used to adjust the target for calls answered in 30 seconds, is to calculate the average 'calls answered in 30 seconds', based on the monthly call answering data from the period February 2013 to March 2014.

The basis for choosing February 2013 to March 2014 as the data range for calculating the 'average calls answered in 30 seconds', is that Endeavour Energy ceased supporting a Retail business at the end of January 2013, and became a true 'Network only' call centre from February 2013. For the period FY 08/09 to end Jan 2013, Endeavour Energy had significantly greater call centre work force and operated in a true multi skilled environment, where first priority always went to handling network calls. As such, network calls were answered in a much quicker time frame due to the economies of scale.

All data used for this calculation comes from Endeavour Energy's call centre reporting application (CC6)

Month	Calls offered to agents	Calls answered	% GOS (Threshold 30 secs)	Calls Answered in 30 Seconds
Feb-13	20,948	19,038	55%	11521
Mar-13	18,034	17,279	85%	15329
Apr-13	16,391	15,550	88%	14424
May-13	19,093	18,249	84%	16038
Jun-13	17,847	16,975	82%	14635
Jul-13	21,780	19,963	66%	14375
Aug-13	18,588	17,600	73%	13529
Sep-13	19,900	18,870	75%	14925
Oct-13	21,283	20,131	73%	15567
Nov-13	21,302	19,984	73%	15550
Dec-13	17,501	16,494	78%	13651
Jan-14	18,646	17,529	76%	14171
Feb-14	17,917	16,971	76%	13691
Mar-14	22,889	20,282	71%	16204
Total	272,119	n/a	75%	203610
Monthly Average	19,437	n/a	75%	14,544
Annual Avg	233,245		75%	174,523

See also Attachment 0.14 to our regulatory proposal.

24. Shared Assets

24.1 Provide Endeavour Energy's shared assets information in Regulatory template 7.4.

Endeavour Energy's shared assets information has been provided in Regulatory template 7.4. Regulatory template 7.4 is part of the Microsoft Excel Workbooks at Attachments RIN.1-3.

25. Revenues and Prices for Standard Control Services

25.1 Provide Endeavour Energy's calculation of the unsmoothed and smoothed revenues, and prices for the purposes of the control mechanism proposed by Endeavour Energy using the AER's post-tax revenue model, which is to be submitted as part of the regulatory proposal.

Endeavour Energy's calculation of the unsmoothed and smoothed revenues, and prices for the purposes of the control mechanism proposed by Endeavour Energy using the AER's post-tax revenue model are provided at Attachment 4.02 of the regulatory proposal.

25.2 Provide details of any departure from the AER's post-tax revenue model for the calculations referred in paragraph 25.1 and the reasons for that departure.

Endeavour Energy has not proposed any departure from the AER's post-tax revenue model for the calculations referred in paragraph 25.1.

26. Indicative Impact on Annual Electricity Bills

26.1 For the purposes of calculating the impact of Endeavour Energy's Regulatory proposal on the annual electricity bill of typical residential and business customers in New South Wales, provide the data/information required in regulatory template 7.6. Provide the data source for each input used for the calculation.

Endeavour Energy has provided the data/information required in regulatory template 7.6. Regulatory template 7.6 is part of the Microsoft Excel Workbooks at Attachments RIN.1-3. Refer to template 7.6 and Attachment V to this RIN for the data sources.

27. Regulatory Asset Base

27.1 Provide Endeavour Energy's calculation of the regulatory asset base for the relevant distribution system in respect of standard control services for each regulatory year of current regulatory control period using the AER's roll forward model, which is to be submitted as part of the regulatory proposal.

Endeavour Energy has calculated 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 provided as Attachment 4.01 to the regulatory proposal.

27.2 Provide details of any departure from the underlying methods in the AER's roll forward model for the calculation referred in 27.1 and the reasons for that departure.

Endeavour Energy has not departed from the underlying methods in the AER's roll forward model for the calculation referred to in paragraph 27.1.

27.3 If the value of the RAB 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.

To comply with the outcomes of the Framework & Approach Stage 1 issued by the AER, Endeavour Energy is required to separate those assets within the metering & load control asset class that relate to the newly classified metering services. In addition, Endeavour Energy attributed relevant non-system assets to the newly classified metering services on a basis that was considered commensurate with the utility provided to those metering services relative to that provided to standard control services.

The calculations underpinning the allocation of assets to the newly classified metering services are contained in the metering model attached to the substantive regulatory proposal at Attachment 0.17.

Confirmation that the allocation of assets to metering services has been appropriately undertaken can be found between the opening RAB values contained in the two PTRM models provided as part of Attachment 4.02 to the substantive regulatory proposal.

28. Depreciation Schedules

28.1(a) Provide Endeavour Energy's calculation of the depreciation amounts for the relevant distribution 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.

The roll forward model has been completed for the current regulatory period and has been included as Attachment 4.01 to the regulatory proposal.

28.1(b) Provide Endeavour Energy's calculation of the depreciation amounts for the relevant distribution system in respect of standard control services for each regulatory year of the forthcoming regulatory control period using the AER's post-tax revenue model, which is to be submitted as part of the regulatory proposal.

The post-tax revenue model has been completed for the current regulatory period and has been included as Attachment 4.02 to the regulatory proposal.

28.2 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 28.1 and the reasons for that departure.

Endeavour Energy has not departed from the underlying methods in the AER's roll forward model and post-tax revenue model for the calculations in 28.1.

28.3 Identify any changes to standard asset lives for existing asset classes from the previous determination. Explain the reason/s for the change and provide relevant supporting information.

There have been no changes to the standard lives for existing asset classes between the current and forecast regulatory control periods.

28.4 For any proposed new asset classes, explain the reason/s for using these new asset classes and provide relevant supporting information on their proposed standard asset lives.

There are no new asset classes proposed for the forthcoming regulatory control period.

28.5 If existing asset classes from the previous determination are proposed to be removed and their residual values to be reallocated to other asset classes, explain the reason/s for the change and provide relevant supporting information. This should include a demonstration of the materiality of the change on the forecast depreciation allowance.

No asset classes have been discontinued between the current regulatory control period and the forthcoming regulatory control period.

28.6 Describe the method used to calculate the remaining asset lives for existing asset classes as at 1 July 2014 (the start of the forthcoming regulatory control period) and provide supporting calculations if the approach differs from that in the roll forward model.

The remaining lives for existing asset classes as at 1 July 2014 were all initially calculated as per the roll forward model.

To reflect the movement of assets from standard control services to the newly classified metering services, Endeavour Energy was required recalculate the PTRM inputs for the metering and load control asset class on the basis of the residual assets within this asset class.

The calculations to derive the remaining life of the residual metering and load control asset class were undertaken on the basis of a weighted average remaining life with the known dollar value being transferred from standard to alternative control services and based on a remaining life of 5 years for the metering assets transferred consistent with the remaining life used for determining the annual revenue requirements for these metering assets as per metering model attached to the substantive regulatory proposal at Attachment 0.17. .

29. Corporate Tax Allowance

29.1 Provide Endeavour Energy's calculation of the estimated cost of corporate income tax for the forthcoming regulatory control period using the AER's post-tax revenue model, which is to be submitted as part of the regulatory proposal.

Refer to Attachment 4.02 to our regulatory proposal

29.2 Provide a demonstration that the calculation referred to in 29.1 complies with clause 6.5.3 of the NER.

The calculation in Attachment 4.02 does not differ from that in the AER's post-tax revenue model

29.3 Provide details of any departure from the AER's post-tax revenue model for the calculations referred to in 29.1 and the reasons for that departure.

Endeavour Energy has not proposed any departures from the AER's post-tax revenue model for the calculation of the estimated cost of corporate income tax for the forthcoming regulatory control period.

29.4 Identify any changes 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.

There are no changes to standard tax asset lives for the existing asset classes from the previous determination.

29.5 Describe the method used to calculate the remaining asset lives for existing asset classes as at 1 July 2014 (the start of the forthcoming regulatory control period) and provide supporting calculations if the approach differs from that in the roll forward model.

Refer to Attachment 4.01 to our regulatory proposal, roll forward model (RFM). The approach does not differ from that in the roll forward model.

29.6 Provide Endeavour Energy's calculation of the tax asset base for the relevant distribution 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.

See Attachment 4.01 to our regulatory proposal, roll forward model (RFM).

29.7 Provide details of any departure from the underlying methods in the AER's roll forward model for the calculation referred to in 31.6 and the reasons for that departure.

There are no departures from the underlying methods in the AER's roll forward model for the calculation referred to in 31.6.

29.8 Identify any differences 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 the capitalisation of expenditure for regulatory accounting purposes and tax accounting purposes.

29.9 Provide calculations to demonstrate if a tax loss carried forward exist as at 1 July 2014. The figures used in these calculations, such as the revenue and operating expenses, should be actuals (with the exception of the final year of the current regulatory control

period that requires an estimate). Identify and provide reasons for any assumptions applied to determine the value of any tax loss carried forward.

There is no tax loss carried forward as at 1 July 2014.

30. Corporate Structure

30.1(a) Provide charts that set out the group corporate structure of which Endeavour Energy is a part.

A chart that sets out the group corporate structure is provided at Attachment U to this RIN.

30.1(b) Provide charts that set out the organisational structure of Endeavour Energy.

A chart that sets out the organisational structure of Endeavour Energy is provided at Attachment T to this RIN.

31. Forecast Map of Distribution System

31.1 Provide a forecast map of Endeavour Energy's distribution system for the forthcoming regulatory control period. This map, together with any appropriate accompanying notes, should also indicate the location of new major network assets proposed to be constructed over the next regulatory control period.

The maps included in the Transmission Network Planning Review (Attachment 5.05 to our proposal) show the location of major new network assets proposed to be constructed during the next regulatory control period.

32. Audit Reports

32.1(a) Provide a Regulatory Audit report in the form of a Special Purpose Financial Report in accordance with the requirements set out at Appendix C.

A Regulatory Audit report from PricewaterhouseCoopers in the form of a Special Purpose Financial Report in accordance with the requirements set out at Appendix C is provided at Attachment RIN.5 and RIN.6.

32.1(b) Provide a Regulatory Audit report in the form of a Review report (for non-financial information) in accordance with the requirements set out at Appendix C.

A Regulatory Audit report from TCFT Business Services in the form of a Review report (for non-financial information) in accordance with the requirements set out at Appendix C is provided at Attachment RIN.7.

32.2 Provide all reports from the Auditor to Endeavour Energy's management regarding the audit review and/or auditors' opinions or assessment.

All reports from the Auditors to Endeavour Energy's management regarding the audit review and/or auditors' opinions or assessment are provided at Attachment RIN.10.

33. Board Resolution

33.1 Provide an extract from the board minutes or a resolution agreed to at a Endeavour Energy board meeting that confirms, to the best of the Board's information, knowledge and belief, the information provided in the response to paragraph 1.1 (being the information to be provided in the Microsoft Excel Workbooks attached at Appendix A is, for Actual Information, true and accurate and where Endeavour Energy cannot provide Actual Information, Endeavour Energy's best estimate.

A copy of the resolution agreed to at an Endeavour Energy Board meeting that confirms, to the best of the Board's information, knowledge and belief, the information provided in the response to paragraph 1.1 (being the information provided in the Microsoft Excel Workbooks attached at Appendix A) is, for Actual Information, true and accurate and where Endeavour Energy cannot provide Actual Information, Endeavour Energy's best estimate is provided at Attachment RIN.8.

34. Transitional Issues

34.1 Provide information on existing potential transitional issues (expressly identified in the Rules or otherwise) which Endeavour Energy expects will have a material impact on it and should be considered by the AER in making its distribution determination. For each issue, set out the following information: the transitional issue; what has caused the transitional issue; how the transitional issue impacts on Endeavour Energy; and how Endeavour Energy considers the transitional issue could be addressed.

Transitional issues arise in relation to the pricing of newly classified Ancillary Network Services (ANS). These services have previously been regulated as part of standard control services. In light of the nature of transitional revenue decision, the AER as part of the Framework & Approach Stage 1 decision decided that these services should continue to be priced within the standard control services revenue targets for the transitional year. Following the transitional year these services will be priced separately.

This creates transitional issues relating to the pricing for these services in standard control services for transitional year and for separate pricing thereafter. Noting that the costs for the newly classified ANS will be recovered as part of standard control services revenues for the transitional year and the policy objective of cost reflective pricing Endeavour Energy concurs with our understanding that the AER will address any issues arising from the Substantive Regulatory decision relevant to the transitional year costs through the standard control services revenues over the following four years.

More broadly there are transitional issues relating to the separation of costs relating to the newly classified ANS and the newly classified metering services. Endeavour Energy has approached the separation of these forecast costs through top down and work order analysis of historic data. This approach ensures both reasonable attribution and allocation of costs across the services provided by Endeavour Energy and also ensures consistency between historic and forecast costs at an aggregate level.

35. Confidential Information

35.2 If Endeavour Energy wishes to make a claim for confidentiality over any Endeavour Energy's Information, provide the details of that claim in accordance with the requirements of the AER's Confidentiality Guideline, as if it extended and applied to that claim for confidentiality.

Endeavour Energy has completed a confidentiality template in accordance with the AER's Confidentiality Guideline and it is at Attachment RIN.9. Also, in the confidential versions of documents the confidential information has been highlighted in yellow shading and public versions of these documents have also been provided. Electronic documents specify in the filename whether it is "public" or "confidential".

35.3 Provide any details of a claim for confidentiality in response to clause 1.2 at the same time as making the claim for confidentiality. Confirm, in writing, that Endeavour Energy consents to the AER disclosing all other of Endeavour Energy's information on the AER website.

In relation to Endeavour Energy's consent to the AER disclosing all other of Endeavour Energy's information that is not a matter that can be required to be addressed as part of a response Regulatory Information Notice.