30 April 2014

Jemena Electricity
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Mr Chris Pattas
General Manager, Network Operations and Development
Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

By Email: AERInquiry@aer.gov.au

Dear Chris

Jemena Electricity Networks (Vic) Ltd: Economic benchmarking Regulatory Information Notice

Jemena Electricity Networks (Vic) Ltd (**JEN**) is pleased to submit its response to the economic benchmarking Regulatory Information Notice (**RIN**) that the Australian Energy Regulator (**AER**) served on JEN on 28 Nov 2013.

The JEN response includes the:

- Excel template with JEN's actual economic benchmarking information
- Excel template with JEN's estimated economic benchmarking information
- Excel template with JEN's consolidated economic benchmarking information
- Excel template with JEN's consolidated colour coded economic benchmarking information
- JEN's audit reports and review reports
- JEN's basis of preparation document with supporting models attached.

JEN notes that approximately 68% of the information provided (by cell) is estimated, of which JEN considers only 16% to be reliable estimates for the purposes of regulatory analysis and/or decision making (colour-coded as yellow, refer to JEN's colour coding explanation in Annexure 2 of JEN's RIN response). JEN has also provided its best estimates for the other 84% of estimated information (colour coded as orange and red) because the RIN compels JEN to do so. However, JEN does not consider these estimates to be reliable or fit for the purpose of regulatory analysis or decision-making.

JEN also notes that it is the smallest stand-alone electricity distributor in Victoria, and one of the smallest in Australia. As a result, JEN's fixed costs of running an electricity network are spread over a much smaller number of customers than JEN's peers, which places JEN at a scale disadvantage in any benchmarking comparison. JEN considers that the AER should take this into account when considering the results of any comparative benchmarking analysis.

JEN provides two copies of its basis of preparation document: a confidential version with identified areas of content that contain materials that are commercial-in-confidence, and a second public version with areas of content that are commercial-in-confidence redacted. JEN has only provided a single (public) version of its Excel templates as they do not contain any confidential information.

Annexure 1 to this letter details the relevant sections of the RIN that JEN considers to be commercial-in-confidence and the basis of the claims.

Annexure 2 to this letter includes a colour coding key which indicates the level of confidence JEN has with estimated input variables and an Excel template that contains JEN's colour coded consolidated economic benchmarking information.

Annexure 3 to this is JEN's basis of preparation document. The document also includes supporting papers and models as attachments.

Annexure 4 to this letter includes the financial audit opinion and review report by KPMG.

Annexure 5 to this letter includes the non-financial audit report by Parsons Brinkerhoff.

Annexure 6 to this letter includes a signed statutory declaration by the Managing Director.

If you have any questions regarding this submission please contact me on (03) 8544 9036 or anton.murashev@jemena.com.au.

Yours sincerely

P.P.

Anton Murashev
Manager Asset Regulation and Strategy

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Jemena Electricity Networks (Vic) Ltd

Response to the economic benchmarking Regulatory Information Notice for the 2006-13 regulatory years

Annexure 1

Confidentiality schedule

Public

30 April 2014

Annexure 1 - Jemena Electricity Networks (Vic) Ltd economic benchmarking RIN

Claims for commercial-in-confidence

The following table sets out specific sections of JEN's economic benchmarking unaudited RIN response that JEN claims to be commercial-in-confidence and the basis of the claim.

JEN has applied the rationale for claiming information as commercial-in-confidence as set out in the AER's confidentiality guideline.

JEN has provided reasons detailing how and why disclosure of the information would cause detriment to the business. JEN understands that this confidential information being available to the AER to perform its functions under the rules provides a public benefit, and has assessed that in all identified cases JEN's confidentiality reasons, together with the benefits already realised through the AER's confidential use of this data, are not outweighed by any additional public benefit to disclosure of the information.

Document containing confidential information	Page and paragraph number of the document which contains confidential information	Classification of confidential information	Description and reasons supporting how and why disclosure of the information would cause detriment which is not outweighed by the public benefit in disclosing the information	Has the confidential information been identified by highlighted yellow shading? If not, please provide reasons	Have public versions of the document been provided? If not please provide reasons
JEN's basis of preparation – Attachment 1 (Procedure 4.4.1 Asset lives – estimated service life of new assets FEB 2014)	Page 109, paragraph 2	Market sensitive cost inputs	The **unit costs** are commercially confidential to JEN because public disclosure could jeopardise JEN's commercial position in future negotiations with prospective service providers.	Yes	Yes

Document containing confidential information	Page and paragraph number of the document which contains confidential information	Classification of confidential information	Description and reasons supporting how and why disclosure of the information would cause detriment which is not outweighed by the public benefit in disclosing the information	Has the confidential information been identified by highlighted yellow shading? If not, please provide reasons	Have public versions of the document been provided? If not please provide reasons
JEN's basis of preparation – Attachment 2 (Procedure 4.4.2 Asset lives – estimated residual service life FEB 2014)	Pages 115-116	Market sensitive cost inputs	The **unit costs** are commercially confidential to JEN because public disclosure could jeopardise JEN's commercial position in future negotiations with prospective service providers.	Yes	Yes

Document containing confidential information	Page and paragraph number of the document which contains confidential information	Classification of confidential information	Description and reasons supporting how and why disclosure of the information would cause detriment which is not outweighed by the public benefit in disclosing the information	Has the confidential information been identified by highlighted yellow shading? If not, please provide reasons	Have public versions of the document been provided? If not please provide reasons
Annexure 4: Financial audit opinion and review report	The entire document	Market sensitive cost inputs	JEN's audit opinion and review report of its economic benchmarking RIN response is confidential in entirety, as there would be harm to both JEN and the Auditor, should the report be publicly disclosed. While JEN is not publicly listed, the Jemena Group has publicly listed debt. Therefore, public information could have value implications for Jemena’s traded debt. If the audit report in question (and potential similar future reports) were to be published, investors could rely on the information in those reports. Most investors would not understand the difference between a statutory audit report and a regulatory audit report. Given this, any potential non-compliance with an AER Regulatory Information Notice (RIN), which may be noted in a regulatory audit report, could mistakenly be perceived by investors as an issue with JEN’s statutory financial reporting. This could damage JEN’s reputation with investors and result in unnecessary costs of JEN issuing explanations and re-assurances to the market.	No. The entire document is commercially confidential	No. The entire document is commercially confidential

Jemena Electricity Networks (Vic) Ltd

Response to the economic benchmarking Regulatory Information Notice for the 2006-13 regulatory years

Annexure 2

Colour coding schedule

Public

30 April 2014

Annexure 2 - Jemena Electricity Networks (Vic) Ltd economic benchmarking RIN

Colour coding key

Colour Code	Availability of data from NSP's primary system	Additional work around/estimation techniques
Green	Available and verifiable	**Simple** – no additional work or minor work around (e.g. source data from a secondary system)
Yellow	Available but with some gaps	**Moderate** – estimate based on statistically significant sample size
Orange	Little or no data available	**Complex** – estimate based on formula, standard parameters or other source
Red	Little or no data available	**Subjective** – based on significant estimates, judgements and assumptions
Black	Not applicable to relevant NSP	Not applicable to relevant NSP

Jemena Electricity Networks (Vic) Ltd

Response to the economic benchmarking Regulatory Information Notice for the 2006-13 regulatory years

Annexure 3

Basis of preparation

Public

30 April 2014

Jemena Electricity Networks (Vic) Ltd

Response to the economic benchmarking Regulatory Information Notice for the 2013 regulatory year

Basis of preparation

Information from CY2006 to CY2013

Public

30 April 2014

Jemena
Vital Service. Vital Planet.

An appropriate citation for this paper is:

Response to the economic benchmarking Regulatory Information Notice for the 2013 regulatory year

Contact Person

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GLOSSARY

JEN	Jemena Electricity Networks (Vic) Limited
RIN	Regulatory Information Notice
AER	Australian Energy Regulator
NEL	National Electricity Law
ACS	Alternative Control Service
RAB	Regulated Asset Base
GL	General Ledger
EBSS	Efficiency Benefit Sharing Scheme
ESC	Essential Services Commission
NPV	Net Present Value
WACC	Weighted Average Cost of Capital
CPI	Consumer Price Index
STPIS	Service Target Performance Incentive Scheme
DUoS	Distribution Use of System
CAM	Cost Allocation Method
RAS	Regulatory Accounting Statements
JAM	Jemena Asset Management Pty Ltd
JAM6	Jemena Asset Management 6 Pty Ltd
WBS	Work Breakdown Structure
SCS	Standard Control Services
ERP	Enterprise Resource Planning
EDPR	Electricity Distribution Price Review
CY	Calendar Year
P&L	Profit and Loss
EBT	Economic benchmarking asset categories
RFM	Roll-forward model
DNSP	Distribution Network Service Providers
DRC	Depreciated Replacement Cost
NS	Network Services
FQ	Fee and quote based services
GIS	Geospatial Information System
TNSP	Transmission Network Service Provider
IMS	Interval Meter Store
FY	Financial Year

CIS	Customer Information System
NMI	National Meter Identifiers
MW	Mega Watts
TT	Thomastown Terminal
MD	Maximum Demand
MVA	Megavolt Amperes
MVAr	Megavolt Ampere Reactive
HV	High Voltage
PF	Power Factor
LV	Low Voltage
OH	Overhead
UG	Underground
OMS	Outage Management System
KPI	Key Performance Indicators
CMOS	Customer Minutes Off Supply
MED	Major Event Day
ORG	Office of the Regulator General
DLF	Distribution Loss Factor
VMS	Vegetation Management System
CFA	Country Fire Authority
BOM	Bureau of Meteorology

OVERVIEW

Jemena Electricity Networks (Vic) Ltd (**JEN**) is required to respond to an economic benchmarking Regulatory Information Notice (**RIN**), covering calendar years 2006 to 2013 (inclusive). RIN data templates are due with the Australian Energy Regulator (**AER**) by 3 Mar 14 (unaudited) and audit reports for the entire back cast period and a statutory declaration providing assurance for all data and accompanying documents is due by 30 Apr 14. The RIN was served upon JEN by the AER under the National Electricity Law (**NEL**) on 29 November 2013.

Section 2.2 of Schedule 2 of the RIN requires JEN to prepare a ‘basis of preparation’ in accordance with the requirements specified in Schedule 1. This document—JEN’s basis of preparation (for each variable and any other information):

1. demonstrates how the information provided is consistent with the requirements of the RIN;
2. explains the source from which JEN obtained the information provided;
3. explains the methodology JEN applied to provide the required information, including the assumptions (if any) JEN made;
4. explains, in circumstances where JEN cannot provide input for a variable using actual information and therefore must provide input using estimated information:
   a) why an estimate is required, including why it is not possible for JEN to use actual financial Information or actual non-financial information (as the case may be, depending on the variable);
   b) the basis for the estimate, including the approach used, assumptions made and reasons why the estimate is JEN’s best estimate, given the information sought in the RIN.

The RIN requires that the basis of preparation—for every variable in the Excel templates—explains the basis upon which JEN prepared information to populate the input cells. JEN notes that the AER intends to publish JEN’s basis of preparation along with the RIN Excel templates.

JEN considers this basis of preparation complies with the AER requirement that the basis of preparation must follow a logical structure that enables auditors, assurance practitioners and the AER to clearly understand how JEN has complied with the requirements of the RIN. JEN has structured this basis of preparation to align with sections of the same numerical template reference in the Excel templates (i.e. section 2. Revenue of this basis of preparation document refers to Excel template 2. Revenue).

JEN has included in its basis of preparation, all other information JEN prepared in accordance with the requirements of RIN B. For example, where JEN chose to disaggregate its Regulated Asset Base (**RAB**) using its own approach in addition to the AER’s standard approach, JEN has explained its approach in detail in its basis of preparation and has attached procedure documents and supporting models.

The actual financial information has been reconciled to the prior year regulatory accounting statements, and the principles underpinning the figures in Revenue and Opex are in line with the statutory accounting policies. There are no material departures from statutory accounting policies, for the purposes of regulatory reporting. An exception is that ~~the disclosure of~~ customer contributions, which are~~is~~ included in the statutory accounts, are excluded from the regulatory accounts.

1.1 PROCESS REQUIREMENTS

JEN's basis of preparation will be audited or reviewed and verified by statutory declaration by 30 April 2014, as part of the audit or review of the Economic Benchmarking Data Templates. The auditor will ***review*** JEN's basis of preparation when conducting their audit of actual information and issuing their review conclusion on the estimated information.

1.2 BEST ESTIMATES

Where JEN cannot populate an input cell in the Excel templates with actual information, it has provided its best estimate, considering data availability constraints, JEN's limited knowledge of how the information may be applied or interpreted and JEN being unaware of a superior estimation technique at the time. As such, JEN cautions the AER from using this data to inform regulatory decisions without first confirming with JEN its understanding of the methodologies used, availability of data and any other limitations that may exist.

Because the back cast dataset requires JEN to populate input cells going back a number of years, JEN has estimated some variables.

Where JEN provides an estimate, it has, in its basis of preparation, explained:

1. why it could not use actual information
2. the basis upon which the estimate was made including detail of the methodology applied, and
3. why it is JEN's best estimate.

1.3 DEFINITIONS OF ACTUAL INFORMATION

JEN has adopted the AER's definition of 'actual information' in its response to the RIN. The RIN and explanatory statement define actual information as:

"Information presented in response to the Notice whose presentation is Materially dependent on information recorded in JEN's historical accounting records or other records used in the normal course of business, and whose presentation for the purposes of the Notice is not contingent on judgments and assumptions for which there are valid alternatives, which could lead to a Materially different presentation in the response to the Notice.

"Accounting records" include trial balances, the general ledger, subsidiary accounting ledgers, journal entries and documentation to support journal entries. Actual financial information may include accounting estimates, such as accruals and provisions, and any adjustments made to the accounting records to populate JEN's regulatory accounts and responses to the Notice.

'Records used in the normal course of business', for the purposes of non-financial information, includes asset registers, geographical information systems, outage analysis systems, and so on."

1.4 WHERE JEN HAS BLACKED OUT CELLS

In some limited circumstances, JEN has blacked out input cells. These circumstances are limited to those that the RIN and its explanatory statement clearly identify as potentially not applicable to JEN.

There are two circumstances where the AER determined that a variable could potentially be not applicable to JEN.

The first circumstance is when JEN does not currently measure the information in accordance with the variable requirement and the AER considers that it be both:

- unnecessarily burdensome for JEN to estimate the information; and
- illogical for JEN to enter ‘0’ in response to the variable when posed as a question.

These cells were shaded orange in the clean Excel templates

- The second circumstance is when JEN has made no material changes (over the course of the back cast time series) to its:
- Cost allocation approach, or
- Basis of preparation for its Regulatory Accounting Statements, or
- the annual reporting requirements.

These cells were shaded blue in the clean Excel templates.

For each variable which the RIN and the Excel templates (through orange or blue shading) identify as potentially not applicable to JEN, JEN has considered whether the variable is actually applicable to it. For example, JEN has blacked out the blue cells in template 3.Opex as JEN has made no material changes (over the course of the back cast time series) to its cost allocation approach.

Where the variable is actually applicable to JEN, JEN has completed the variable in accordance with the RIN and its explanatory statement. However, where specified above, in some cases JEN has blacked out the cells relating to that variable rather than input information. This does not mean that JEN has not responded to part of the RIN. Rather, it means that, in the circumstances set out above, the correct response required by the RIN is a blacked out cell. JEN has not applied any other use of blacked out or empty cells.

1.5 HOW JEN’S RESPONSE TO EACH VARIABLE MEETS THE REQUIREMENTS OF THE RIN

JEN considers that all information provided in this response—for each variable and any other information—is consistent with the requirements of the RIN. This is evident in that:

- JEN has provided complete Microsoft Excel workbooks attached at Appendix A of the RIN that accord to the RIN and the instructions and definitions in appendix B of the RIN
- JEN has provided a basis of preparation that demonstrates JEN’s compliance with each of the information requirements. JEN’s basis of preparation, for each variable and any other information:
  - Explains the source from which JEN obtained the information provided
  - Explains the methodology JEN applied to provide the required information, including any assumptions made
  - Where JEN has estimated information, its basis of preparation explains why an estimate was required, including why it was not possible for JEN to use actual information, explains the basis of the estimate, including the approach used, assumptions made and why JEN considers the estimate to be JEN’s best estimate

- JEN has provided supporting information or documentation used to comply with the requirements of the RIN
- JEN will provide the audit and review reports in accordance with the requirements of the RIN by 30 April 2014

2. REVENUE WORKSHEET

2.1 REVENUE GROUPING BY A CHARGEABLE QUANTITY

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DREV0101–DREV0109 SCS 2006-**2013**	The data is sourced from JEN's two billing systems. The data is then captured in the LCYYYY.xls on a monthly basis and is summed in worksheet Year to date. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in the LCYYYY.xls on a monthly basis and is summed in worksheet Year to date.	N/A

Variable	Source and why actual	Methodology	Assumptions
DREV0110 SCS 2006-2009	The data is sourced from JEN's two billing systems. The data is then captured in the prescribed metering Data YYYY.xls, each month and is summed in worksheet Year to Date. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue for each component. The data is then captured in the prescribed metering Data YYYY.xls, each month and is summed in worksheet Year to Date.	N/A
DREV0111 ACS 2006-2013	Alternative Control Service (**ACS**) data 2006-2013.xlsx, in worksheet Summary. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	The data is obtained from JEN's billing systems. The data is then extracted from the following databases: ACS_CISPLUS_Entries.mdb ACS_CISPLUS_Entries_2006-2009.mdb ACS_SAP-ISU_Entries.mdb The data is then captured in ACS data 2006-2013.xls, worksheet Summary.	N/A

Variable	Source and why actual	Methodology	Assumptions
DREV0112 ACS 2006-2013	ACS data 2006-2013.xlsx, worksheet Summary. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	The data is extracted from the general ledger (**GL**) accounts listed below which is initially extracted from JEN's billing systems; 41075018 period 2006 to 2010. 41075081 period 2006 to March 2012. 41075067 period 2006 to 2007. 5210000100 for the period April 2012 to 2013. The data is then obtained from JEN's Trial balance or GL extract for the period 2006 to 2013.	N/A
DREV0113 ACS 2006-2013	ACS data 2006-2013.xlsx, worksheet Summary. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	Data obtained from Trial balance for 2006 to 2011. Where only GL accounts marked as ACS are summed, routine new connections (DREV0111) is subtracted from ACS to derive other ACS (DREV0113) for each calendar year. Data obtained from RIN A Schedule 19 for the period 2012 to 2013, this information is initially extracted from the GL. Where the total of the fee based and quoted based charges are summed, once summed the routine new connections charge (DREV0111) is subtracted for each calendar year to derive DREV0113.	N/A

ESTIMATED INFORMATION

No estimated information is provided.

2.2 REVENUE GROUPING BY CUSTOMER TYPE OR CLASS

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DREV0201–DREV0205 SCS 2006-2013	The data is sourced from JEN's two billing systems. The data is then captured in the LCYYYY.xls on a monthly basis and is summed in worksheet Year to date. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in the LCYYYY.xls on a monthly basis and is summed in worksheet Year to date.	N/A
DREV0206 SCS SCS 2006-2013	The data is sourced from JEN's two billing systems. The data is then captured in the prescribed metering Data YYYY.xls, each month and is summed in worksheet Year to Date. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue for each component.	N/A

Variable	Source and why actual	Methodology	Assumptions
DREV0206 ACS 2006-2013	ACS data 2006-2013.xlsx, worksheet Summary. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of Better Regulation Explanatory Statement: regulatory information notices to collect information for Economic Benchmarking November 2013.	Summation of DREV0111, DREV0112 & DREV0113	N/A

ESTIMATED INFORMATION

No estimated information is provided.

2.3 REVENUE (PENALTIES) ALLOWED (DEDUCTED) THROUGH INCENTIVE SCHEMES

ACTUAL INFORMATION

No actual information is provided.

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DREV0301	This variable is an estimate as the Efficiency Benefit Sharing Scheme (**EBSS**) forms part of the building block revenue determined at the beginning of each regulatory period.	Step 1: Replicate the Essential Services Commission (**ESC**) and AER's calculations to calculate the net present value (**NPV**) of the building block revenues and the smoothed revenues using a real Weighted Average Cost of Capital (**WACC**) for the period 2006-10 and a nominal WACC for the	Consumer Price Index (**CPI**) is assumed to 2.7% for calendar year 2015, Actual CPI for previous years is weighted average for the eight capital cities for the September quarter, on a one year lag basis.	This is considered JEN's best estimate as the methodology applies a relative share as determined from the building block revenue for each regulatory period. The relative share associated with EBSS is then applied to the actual

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	As part of the price reviews, the EBSS penalties/rewards are calculated for each year of the 5 year revenue period. However, these calculations are based on total revenues for the period which are smoothed. As a result, it is not possible for JEN to identify the actual EBSS component for any of the annual regulatory years as per the RIN requirements. Hence this information has to be estimated.	period 2011-15. Step 2: Calculate the relative share of the building block components that contribute to the NPV calculations. Step 3: Re-state the building block and smoothed revenues to nominal dollars using actual CPI instead of the AER CPI forecast. Step 4: Notionally break down the smoothed revenue into building block components (using the relative share calculated in step 2). Step 5: Apply the EBSS relative share from the building block for the Regulatory periods 2006-2011 and 2011-2015 to the actual revenue earned for each calendar year. Where; actual revenue earned = actual revenue reported net of any incentive mechanism schemes, and EBSS relative share is an average for each regulatory period.	L factor considered part of actual revenue earned as it is insignificant at $16k p.a.	revenue earned net of any incentive mechanisms.
DREV0302	There are two components to the Service Target Performance Incentive Scheme (**STPIS**); the S factor true up and the STPIS. In both cases the amount needs to	Step 1: Replicate the ESC and AER's calculations to calculate the NPV of the building block revenues and the smoothed revenues using a real WACC for the period 2006-10 and a nominal WACC for the period	Consumer Price Index (**CPI**) is assumed to 2.7% for calendar year 2015, Actual CPI for previous years is weighted average for the eight capital cities for the September quarter, on a one year lag	This is considered JEN's best estimate as the methodology applies a relative share as determined from the building block revenue for each

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	be estimated. This variable is an estimate as the S factor true up forms part of the building block revenue determined at the beginning of each regulatory period. In addition to this the STPIS component is also an estimate it forms part of the Distribution Use of System (**DUoS**) tariff: DUoS price path is (1+CPI)*(1-X)*(1+S")*(1+L). The STPIS scheme does not determine a revenue amount. It determines an s-factor, which modifies the total price change we can apply to our tariffs in a given year, in addition to the f-factor, inflation and transmission pass throughs. This then becomes just an input to movements in individual tariffs, which can differ from tariff to tariff. We do not keep track, in the individual tariffs, of an s-factor component. Therefore, while we know how much revenue we get from each customer, we never know how much of that revenue is due to the s-factor component of that customer's price.	2011-15. Step 2: Calculate the relative share of the building block components that contribute to the NPV calculations. Step 3: Re-state the building block and smoothed revenues to nominal dollars using actual CPI instead of the AER CPI forecast. Step 4: Notionally break down the smoothed revenue into building block components (using the relative share calculated in step 2). Step 5: Apply the S factor true up relative share from the building block for the Regulatory periods 2006-2011 and 2011-2015 to the actual revenue earned for each calendar year. Step 6: S factor = (actual revenue earned – actual revenue earned)/ (1+ S") DREV0302 is the sum of Step 5 and Step 6 above. Where; actual revenue earned = actual revenue	basis. L factor considered part of actual revenue earned as it is insignificant at $16k p.a.	regulatory period. The relative share associated with S factor true up is then applied to the actual revenue earned net of any incentive mechanisms.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		reported net of any incentive mechanism schemes S true factor relative share is an average for each regulatory period		

3. OPEX WORKSHEET

3.1 OPEX CATEGORIES

ACTUAL INFORMATION

JEN has filled out cells in 3.1.1 opex categories as the AER has made material changes (over the course of the back cast time series) to JEN's Annual reporting requirements. This was due to the AER requiring different cost categorisations when it introduced the Annual RIN in CY2011 to replace the reporting requirements of the Essential Service Commission of Victoria:

Variable	Source and why actual	Methodology	Assumptions
SCS DOPEX0101 (Routine) DOPEX0102 (Condition) DOPEX0104 (Emergency) DOPEX0105 (Inspection) **(CY2011–CY2013)**	Data (Maintenance and opex) is extracted from Appendix B of JEN's CY2011 to CY 2013 annual RIN responses.	Maintenance items disclosed in Appendix B of the RIN's are sourced from SAP, the ERP system that JEN uses to capture its financial and some operational information. Conceptually, JEN's cost collection process uses a combination of cost and profit centres to collect costs at the macro level. Activities or networks are set up to collect costs at a micro level. These activities/networks are designed to collect costs based on the activity on which an individual works and to accept any external costs associated with that activity e.g. Faults, Emergencies, and Standards and Procedures. Note that the SAP network codes are also designed to identify the Regulatory category i.e. SCS, Public Lighting, ACS, etc. JEN uses time writing to capture internal labour costs. Jemena has been improving its capturing of time writing data over the past few years. Where practical and appropriate all employees time write to an activity/network or a client e.g. JEN. These form the direct costs incurred	Activities/networks in SAP are not setup to aggregate to these regulatory categories. An experienced Senior Engineer provided advice on how the activities can be allocated (% based) into these categories (routine, condition based and emergency). This allocation methodology was applied in JEN's annual RIN responses for CY11, 12 and refreshed for CY13.

Variable	Source and why actual	Methodology	Assumptions
		for a respective activity. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER approved Cost Allocation Method (**CAM**). These costs are inclusive of any related party margins applicable for the period 1 Apr 10 to 31 Mar 12 JEN has a comprehensive model which underpins the maintenance costs disclosed in Appendix B of the RIN responses and previous RAS's.	
SCS DOPEX0103 (Vegetation control), **(CY2006 – CY2013)**	SAP report (Y_AGLTREED02000347) generated by JEN's legacy and current accounting systems.	SAP reports for this activity are executed to gather the relevant direct costs. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER approved CAM. These costs are inclusive of any related party margins applicable for the period 1 Apr 10 to 31 Mar 12	None
SCS DOPEX0106 (SCADA), **(CY2008 – CY2013)**	Regulatory accounting statements for CY08 – CY10 and annual RIN responses for CY11 to CY13	Sourced directly from SAP by executing the standard SAP transactions, which deliver the reports for this activity. This activity is mapped to the specific regulatory category. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER approved CAM. These costs are inclusive of any related party margins applicable for the period 1 Apr 10 to 31 Mar 12 .	None

Variable	Source and why actual	Methodology	Assumptions
SCS DOPEX0107 (Others) **CY2011 – CY2013**	Appendix B of the CY2011 to CY2013 annual RIN responses.	Information is sourced from JEN's related parties (Jemena Asset Management Pty Ltd (**JAM)** and Jemena Asset Management 6 Pty Ltd (**JAM6**)). CY11 - CY13 data is based on data collected by the Work Breakdown Structure (**WBS**) code.	None
SCS DOPEX0108 (Metering) **CY2008**	Regulatory accounting statements for CY08	Sourced directly from SAP by executing the standard SAP transactions, which deliver the reports for this activity. This activity is mapped to the specific regulatory category. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER approved CAM. These costs are inclusive of any related party margins applicable for the period 1 Apr 10 to 31 Mar 12 .	None
ACS DOPEX0109 (Public Lighting) **CY2008– CY2013**	Regulatory accounting statements for CY08 – CY10 and annual RIN responses for CY11 to CY13	SAP network codes are also designed to identify the Regulatory category i.e. Standard Control Services (**SCS**), Public Lighting, ACS, etc. The costs are collected into activities which align to the Public Lighting regulatory category. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER approved CAM. These costs are inclusive of any	None

Variable	Source and why actual	Methodology	Assumptions
		related party margins applicable for the period 1 Apr 10 to 31 Mar 12	
ACS DOPEX0110 (Other ACS– Reserve Feeder) **CY2011– CY2013**	Annual RIN responses for CY11 to CY13	In order to estimate the cost associated with the reserve feeder service JEN adopted the following approach: 1. activity cost centres were identified in JEN's operational works program which are related to the provision of operational and maintenance ('O&M') service for distributing electricity to customers. This included reserve feeder service customers 2. these activities were proportioned for high voltage distribution, which is where reserve feeder services are normally provided 3. the high voltage distribution proportion is then applied to the costs of the activities to derive the estimated cost of the O&M service for high voltage distribution 4. these costs were then divided by the system demand forecast (in kW) to derive the estimated $ cost per kW unit for the O&M service for high voltage distribution 5. this $/kW rate was then multiplied by the billed demand (in kW) associated with customers receiving a reserve feeder service.	None
SCS DOPEX0112– DOPEX0124	Regulatory accounting statements for CY08 – CY10 and annual RIN responses for CY11 to CY13	"Activities" items disclosed in Appendix B of JEN's annual RIN responses and previous RAS's are sourced from SAP, the Enterprise Resource Planning (ERP) system that JEN uses to capture its	None

Variable	Source and why actual	Methodology	Assumptions
except *DOPEX0119* *DOPEX0120* **CY2008– CY2013**		financial and some operational information. Conceptually, JEN's cost collection process uses a combination of cost and profit centres to collect costs at the macro level. Activities or networks are set up to collect costs at a micro level. These activities/networks are designed to collect costs based on the activity on which an individual works and to accept any external costs associated with that activity e.g. Faults, Emergencies, and Standards and Procedures. Note that the SAP network codes are also designed to identify the Regulatory category i.e. SCS, Public Lighting, ACS, etc. Jemena uses time writing to capture internal labour costs. Jemena has been improving its capturing of time writing data over the past few years. Where practical and appropriate, all employees time write to an activity/network or a client e.g. JEN. These form the direct costs incurred for a respective activity. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER-approved CAM. These costs are inclusive of any related party margins applicable for the period 1 Apr 10 to 31 Mar 12 JEN has a comprehensive model which underpins the maintenance costs disclosed in Appendix B of the RINs responses and previous RASs.	
SCS DOPEX0119	JEN's accounting system and specific to a GL account.	The data is considered actual as it is extracted from the relevant General Ledger.	None

Variable	Source and why actual	Methodology	Assumptions
(licence fee), **CY2006– CY2013**			
DOPEX0120 (GSL payment), **CY2006– CY2013**	JEN's accounting system and specific to a GL account.	The data is considered actual as it is extracted from the relevant General Ledger.	None
ACS DOPEX0101 – DOPEX0127 (2011 – 2013)	Data extracted from JEN's annual RIN responses for CY 2011 and 2012 submitted to the AER.	"Activities" items disclosed in Appendix B of JEN's annual RIN responses and previous RASs are sourced from SAP, the ERP system that JEN uses to capture its financial and some operational information. Conceptually, JEN's cost collection process uses a combination of cost and profit centres to collect costs at the macro level. Activities or networks are set up to collect costs at a micro level. These activities/networks are designed to collect costs based on the activity on which an individual works and to accept any external costs associated with that activity e.g. Faults, Emergencies, and Standards and Procedures. Note that the SAP network codes are also designed to identify the Regulatory category i.e. SCS, Public Lighting, ACS, etc. JEN uses time writing to capture internal labour costs. JEN has been improving its capturing of time writing data over the past few years. Where practical and appropriate, all employees time write to an activity/network or a client e.g. JEN. These form the direct costs incurred	None

Variable	Source and why actual	Methodology	Assumptions
		for a respective activity. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER-approved CAM. These costs are inclusive of any related party margins applicable for the period 1 Apr 10 to 31 Mar 12 JEN has a comprehensive model which underpins the maintenance costs disclosed in Appendix B of the RINs responses and previous RASs.	
Table 3.1.2 DOPEX0101B to DOPEX0121 B (2006)	Data extracted from JEN's annual RAS responses for FY 2006.	"Activities" items disclosed in Appendix B of JEN's annual RIN responses and previous RAS's are sourced from SAP, the Enterprise Resource Planning (**ERP**) system that JEN uses to capture its financial and some operational information. Conceptually, JEN's cost collection process uses a combination of cost and profit centres to collect costs at the macro level. Activities or networks are set up to collect costs at a micro level. These activities/networks are designed to collect costs based on the activity on which an individual works and to accept any external costs associated with that activity e.g. Faults, Emergencies, and Standards and Procedures. Note that the SAP network codes are also designed to identify the Regulatory category i.e. SCS, Public Lighting, ACS, etc. Jemena uses time writing to capture internal labour costs. Jemena has been improving its capturing of time writing data over the past few years. Where practical and appropriate, all employees time write to an activity/network or a client e.g. JEN. These form the direct costs incurred for a respective activity. JEN allocates overheads to	None

Variable	Source and why actual	Methodology	Assumptions
		these activities based on its internal policies and in accordance with the AER-approved CAM. These costs are inclusive of any related party margins applicable for the period 1 Apr 10 to 31 Mar 12 JEN has a comprehensive model which underpins the maintenance costs disclosed in Appendix B of JEN's 2011-2013 responses to RIN A and previous RASs. The numbers have been calendarised and categorised per current RIN A classification in table 3.1.1. Due to this reason, the total of table 3.1.1 cannot agree with the total of table 3.1.2.	
Table 3.1.2 DOPEX0101B to DOPEX0121 B (2007)	Data extracted from JEN's annual RAS response for Year 2007, which was a 18 month period from July'06 to Dec'06.	"Activities" items disclosed in Appendix B of JEN's annual RIN responses and previous RAS's are sourced from SAP, the Enterprise Resource Planning (**ERP**) system that JEN uses to capture its financial and some operational information. Conceptually, JEN's cost collection process uses a combination of cost and profit centres to collect costs at the macro level. Activities or networks are set up to collect costs at a micro level. These activities/networks are designed to collect costs based on the activity on which an individual works and to accept any external costs associated with that activity e.g. Faults, Emergencies, and Standards and Procedures. Note that the SAP network codes are also designed to identify the Regulatory category i.e. SCS, Public Lighting, ACS, etc. Jemena uses time writing to capture internal labour costs. Jemena has been improving its capturing of time writing data over the past few years. Where practical and appropriate,	None

Variable	Source and why actual	Methodology	Assumptions
		all employees time write to an activity/network or a client e.g. JEN. These form the direct costs incurred for a respective activity. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER-approved CAM. These costs are inclusive of any related party margins applicable for the period 1 Apr 10 to 31 Mar 12 JEN has a comprehensive model which underpins the maintenance costs disclosed in Appendix B of JEN's 2011-2013 responses to RIN A and previous RASs. The numbers have been calendarised and categorised per current RIN A classification in table 3.1.1. Due to this reason, the total of table 3.1.1 cannot agree with the total of table 3.1.2.	
Table 3.1.2 DOPEX0101B to DOPEX0121 B (2008-2009)	Data extracted from JEN's annual RAS responses for CY 2008, and CY2009.	"Activities" items disclosed in Appendix B of JEN's annual RIN responses and previous RAS's are sourced from SAP, the Enterprise Resource Planning (**ERP**) system that JEN uses to capture its financial and some operational information. Conceptually, JEN's cost collection process uses a combination of cost and profit centres to collect costs at the macro level. Activities or networks are set up to collect costs at a micro level. These activities/networks are designed to collect costs based on the activity on which an individual works and to accept any external costs associated with that activity e.g. Faults, Emergencies, and Standards and Procedures. Note that the SAP network codes are	None

Variable	Source and why actual	Methodology	Assumptions
		also designed to identify the Regulatory category i.e. SCS, Public Lighting, ACS, etc. Jemena uses time writing to capture internal labour costs. Jemena has been improving its capturing of time writing data over the past few years. Where practical and appropriate, all employees time write to an activity/network or a client e.g. JEN. These form the direct costs incurred for a respective activity. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER-approved CAM. These costs are inclusive of any related party margins applicable for the period 1 Apr 10 to 31 Mar 12 JEN has a comprehensive model which underpins the maintenance costs disclosed in Appendix B of JEN's 2011-2013 RIN A responses and previous RASs.	
Table 3.1.2 DOPEX0101B to DOPEX0121 B (2010)	Data extracted from JEN's annual RAS responses for CY 2010.	"Activities" items disclosed in Appendix B of JEN's annual RIN responses and previous RAS's are sourced from SAP, the Enterprise Resource Planning (**ERP**) system that JEN uses to capture its financial and some operational information. Conceptually, JEN's cost collection process uses a combination of cost and profit centres to collect costs at the macro level. Activities or networks are set up to collect costs at a micro level. These activities/networks are designed to collect costs based on the activity on which an individual works and to accept any external costs associated with that activity e.g. Faults, Emergencies, and Standards and Procedures. Note that the SAP network codes are also designed to identify the Regulatory category i.e.	None

Variable	Source and why actual	Methodology	Assumptions
		SCS, Public Lighting, ACS, etc. Jemena uses time writing to capture internal labour costs. Jemena has been improving its capturing of time writing data over the past few years. Where practical and appropriate, all employees time write to an activity/network or a client e.g. JEN. These form the direct costs incurred for a respective activity. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER-approved CAM. These costs are inclusive of any related party margins applicable for the period 1 Apr 10 to 31 Mar 12 JEN has a comprehensive model which underpins the maintenance costs disclosed in Appendix B of JEN's 2011-2013 responses to RIN A and previous RASs. The related party margin charged to JEN for the period Apr'10 to Dec'10, which was only disclosed in the Related Party Transactions schedule of the RAS submission, but was not included in any other tables, has now been allocated across all relevant opex and capex expenditures. In addition unregulated items e.g. Joint use of Poles and AMI metering are also excluded from table 3.1.1 by definition, as the table requests SCS costs only.. Due to these reasons, the total of table 3.1.1 cannot agree with the total of table 3.1.2.	

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
SCS DOPEX0101 (Routine) DOPEX0102 (Condition) DOPEX0104 (Emergency) DOPEX0105 (Inspection) **(CY2006 – CY2010)**	Activities/networks in SAP are not setup to aggregate to these regulatory categories. An experienced Senior Engineer provided advice on how the activities can be allocated (% based) into these categories (routine, condition based and emergency).	Maintenance items disclosed in Appendix B of the RIN's are sourced from SAP, the ERP system that JEN uses to capture its financial and some operational information. Conceptually, JEN's cost collection process uses a combination of cost and profit centres to collect costs at the macro level. Activities or networks are set up to collect costs at a micro level. These activities/networks are designed to collect costs based on the activity on which an individual works and to accept any external costs associated with that activity e.g. Faults, Emergencies, and Standards and Procedures. Note that the SAP network codes are also designed to identify the Regulatory category i.e. SCS, Public Lighting, ACS, etc. Jemena uses time writing to capture internal labour costs. Jemena has been improving its capturing of time writing data over the past few years. Where practical and appropriate, all employees time write to an activity/network or a client e.g. JEN. These form the direct costs incurred for a respective activity. JEN allocates overheads to these activities based on its internal policies and in accordance with the AER-approved CAM. These costs are inclusive of any related party margins applicable for the period 1 Apr 10 to 31 Mar 12	Activities/networks in SAP are not setup to aggregate to these regulatory categories. An experienced Senior Engineer provided advice on how the activities can be allocated (% based) into these categories (routine, condition based and emergency). This allocation methodology was applied in JEN's annual RIN responses for CY11, CY12 and refreshed for CY13. As this categorisation was not applicable in historical Regulatory Accounting Statements (**RAS**) i.e. prior to CY11, JEN applied the allocation methodology used in CY11 & 12 to the prior years' maintenance costs as disclosed in those audited RASs.	This is the only workable method, other than trawling through individual activity / network / internal order data for the years 2006 to 2010 and then applying the allocation of the engineers to each of the years. However, this would be highly time consuming and the allocation % proposed by the engineer would not be significantly different from the current approach.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		JEN has a comprehensive which underpins the maintenance costs disclosed in Appendix B of the RIN responses and previous RASs. Consistent with JEN's response to the AER's EDPR RIN in the last round of price reviews, for year 2010, adjustments were made to historical RAS expenditures in the Economic Benchmarking Opex template to ensure a proper reflection of the related party margins applicable for the period 1 Apr 10 to 31 Mar 12		
SCS DOPEX0106 (SCADA), **(CY2006 – CY2007)**	The RASs for CY06 and CY07 were completed on a June financial year end, a legacy process inherited from JEN's prior owner. However, JEN has previously converted this data to calendar years as part of its response to the RINs issued for the previous Electricity Distribution Price Review (**EDPR**). JEN has used those prior RIN responses as the basis for the data disclosure in this RIN.	Underlying monthly or quarterly data, where possible, or pro-rata calculation where not available.	The assumption is that the cost in the activities / networks / internal orders flowed evenly across the period so that prorated costs represent actual cost.	The EDPR submission has already been used by the AER in regulatory decisions. It is therefore best to use a consistent methodology.
SCS DOPEX0107	As above.	As above.	As above.	As above.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
(Others) **CY2006 – CY2007**				
SCS DOPEX0108 (Metering) **CY2006 – CY2007**	As above.	As above.	As above.	As above.
ACS DOPEX0109 (Public Lighting) **CY2006 – CY2007**	The RASs for CY06 and CY07 were completed on a June financial year end, a legacy process inherited from JEN's prior owner. However, JEN has previously converted this data to calendar years as part of its response to the RINs issued for the previous EDPR. JEN has used those prior RIN responses as the basis for the data disclosure in this RIN. However, neither the EDPR submission, nor the RAS had a separation of cost between "Maintenance" Public Lighting and "Activity" Public Lighting.	Underlying monthly or quarterly data, where possible, or pro-rata calculation where not available. The costs are collected into activities which align to the Public Lighting category. The average proportion of "Activity" Public Lighting cost to the total Public Lighting cost for the years CY2011 to CY2013 is used to split costs between "Maintenance Public Lighting" and the "activity" Public Lighting.	The assumption is that the cost in the activities / networks / internal orders flowed evenly across the period so that prorated costs represent actual cost. That average "Activity" and "Maintenance" proportions of the total costs over 2011-2013 accurately represent the proportional split over all prior years.	The EDPR submission has already been used by the AER in regulatory decisions. It is therefore best to use a consistent methodology. JEN is not aware of a superior estimation technique for splitting "Activity" and "Maintenance" costs.
ACS DOPEX0109 (Public Lighting)	Neither the EDPR submission, nor the RAS had a separation of cost between "Maintenance" Public Lighting and "Activity"	Sourced the information from the RAS submissions for the relevant years. The average proportion of "Activity" Public	That average "Activity" and "Maintenance" proportions of the total costs over 2011-2013 accurately represent the proportional split over all prior years.	JEN is not aware of a superior estimation technique for splitting "Activity" and "Maintenance" costs.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
CY2008 – CY2010	Public Lighting.	Lighting cost to the total Public Lighting cost for the years CY2011 to CY2013 is used to split costs between "Maintenance Public Lighting" and the "activity" Public Lighting.		
ACS DOPEX011 (Other ACS – Reserve Feeder) **CY2006-CY2010**	Reserve feeder costs are not captured with a unique cost collector that is directly verifiable within JEN's internal business records for years 2006-10. Therefore JEN's engineers provided their best estimate of the proportion of costs from various activities which relate to this service. Thereby the data relating to these variables is considered to be an estimate.	In order to estimate the cost associated with the reserve feeder service JEN adopted the following approach: 1. activity cost centres were identified in JEN's operational works program which are related to the provision of operational and maintenance ('O&M') service for distributing electricity to customers. This included reserve feeder service customers 2. these activities were proportioned for high voltage distribution, which is where reserve feeder services are normally provided 3. the high voltage distribution proportion is then applied to the costs of the activities to derive the estimated cost of the O&M service for high voltage distribution 4. these costs were then divided by the system demand forecast (in kW) to derive the estimated $ cost per kW unit for the O&M service for high voltage distribution 5. this $/kW rate was then multiplied by the billed demand (in kW) associated with customers receiving a reserve feeder service.	None.	This is JEN's best estimate because it is underpinned by as much 'actual information' as possible. The only element estimated was the proportion of maintenance activities that contribute to the cost for raw peak demand. This was provided by an experienced JEN engineer. Furthermore, JEN is not aware of a superior estimation technique.
SCS	The RASs for CY06 and CY07	Underlying monthly or quarterly data, where	The assumption is that the cost in the	The EDPR submission has

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPEX0112 – DOPEX0115 **CY2006 – CY2007**	were completed on a June financial year end, a legacy process inherited from JEN's prior owner. However, JEN has previously converted this data to calendar years as part of its response to the RINs issued for the previous EDPR. JEN has used those prior RIN responses as the basis for the data disclosure in this RIN.	possible, or pro-rata calculation where not available.	activities / networks / internal orders flowed evenly across the period so that prorated costs represent actual cost.	already been used by the AER in regulatory decisions. It is therefore best to use a consistent methodology.
SCS DOPEX0116 (Regulatory cost) **CY2006 – CY2007**	As above The Regulatory Cost included the Licence Fee.	As above. The Licence fee has been deducted from regulatory costs reported in the regulatory accounts where licence fee was not separately disclosed.	The assumption is that the cost in the activities / networks / internal orders flowed evenly across the period so that prorated costs represent actual cost. The balancing number left after deducting Licence Fees is Regulatory Cost.	As above.
SCS DOPEX0116 (Regulatory cost) **CY2008 – CY2009**	The Regulatory Cost included the Licence Fee.	"Activities" items disclosed in Appendix B of JEN's annual RIN responses and previous RAS' are sourced from SAP, the ERP system that JEN uses to capture its financial and some operational information. The amount is sourced directly from the RAS submitted and adjusted for the following: • The Licence fee has been deducted from regulatory costs reported in the regulatory accounts where licence fee was not	The balance cost left after deducting Licence Fees and Regulatory Reset costs is Regulatory Cost.	JEN is not aware of a superior estimation technique.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		separately disclosed. • The Regulatory Reset has been deducted from regulatory costs reported in the regulatory accounts where Regulatory Reset was not separately disclosed. Consistent with JEN's response to the AER's EDPR RIN in the last round of price reviews, for years 2009 and 2010, adjustments were made to historical RAS expenditures in the Economic Benchmarking Opex template to ensure a proper reflection of the related party margins applicable for the period 1 Apr 10 to 31 Mar 12 .		
SCS DOPEX0116 (Regulatory cost) **CY2010**	The Regulatory Cost included the Licence Fee.	"Activities" items disclosed in Appendix B of JEN's annual RIN responses and previous RAS' are sourced from SAP, the ERP system that JEN uses to capture its financial and some operational information. The "previous year" amount submitted in the RIN for CY2011 for Regulatory cost is adjusted for the Licence fee and regulatory reset cost which have been deducted as these were not separately disclosed.	The balance cost left after deducting Licence Fees and Regulatory Reset costs is Regulatory Cost.	As above.
SCS DOPEX0118 (IT cost)	IT costs are not captured in the JEN GL directly, but are allocated to JEN from a related party. Also, the RASs for CY06 and	Underlying monthly or quarterly data, where possible, or pro-rata calculation where not available, consistent with JEN's response to the previous EDPR RIN.	The proportion of ACS costs to the total costs for the years 2011 to 2013 is representative of the actual proportions for each year 2006 to 2008.	JEN is not aware of a superior estimation technique.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
CY2006 – CY2008	CY07 were completed on a June financial year end, a legacy process inherited from JEN's prior owner. However, JEN has previously converted this data to calendar years as part of its response to the RINs issued for the previous EDPR. JEN has used those prior RIN responses as the basis for the data disclosure in this RIN. The IT costs in the RAS were in total and not split between SCS and ACS.	The average proportion of ACS IT cost to total IT costs for the years CY2011 to CY2013 is used to estimate cost splits between SCS and ACS for 2006-2008.		
SCS DOPEX0118 (IT cost) **CY2009**	IT costs are not captured in the JEN GL directly, but are allocated to JEN from a related party. The IT costs in the RAS were in total and not split between SCS and ACS.	"Activities" items disclosed in Appendix B of JEN's RIN responses and previous RASs are sourced from SAP, the ERP system that JEN uses to capture its financial and some operational information. The average proportion of ACS IT cost to the total IT cost for the years CY2011 to CY2013 is used to estimate cost split between SCS and ACS.	The proportion of ACS costs to the total costs for the years 2011 to 2013 is representative of the actual proportions in the relevant prior year.	As above.
SCS DOPEX0118A(IT cost) **CY2010**	As above.	As above.	As above.	As above.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
SCS DOPEX0123 (Other SCS cost (a)) **CY2006 – CY2007**	The RASs for CY06 and CY07 were completed on a June financial year end, a legacy process inherited from JEN's prior owner. However, JEN has previously converted this data to calendar years as part of its response to the RINs issued for the previous EDPR. JEN has used those prior RIN responses as the basis for the data disclosure in this RIN.	Underlying monthly or quarterly data, where possible, or pro-rata calculation where not available.	The assumption is that the cost in the activities / networks / internal orders flowed evenly across the period so that prorated costs represent actual cost. The balance cost left after deducting IT cost is Other SCS Cost.	The EDPR submission has already been used by the AER in regulatory decisions. It is therefore best to use a consistent methodology.
SCS DOPEX0123 (Other SCS cost (a)) **CY2008 – CY2009**	The Other SCS costs included the IT costs.	"Activities" items disclosed in Appendix B of JEN's RIN responses and previous RASs are sourced from SAP, the ERP system that JEN uses to capture its financial and some operational information. The amount is sourced directly from the RAS submitted and adjusted for the following: The IT cost has been deducted from Other SCS costs reported in the regulatory accounts, where IT cost was not separately disclosed. Consistent with JEN's response to the AER's EDPR RIN in the last round of price reviews, for years 2009 and 2010, adjustments were made to historical RAS expenditures in the Economic Benchmarking Opex template to ensure a proper reflection of the related party margins applicable for the period 1 Apr	The balance cost left after deducting IT Costs is Other SCS Cost.	JEN is not aware of a superior estimation technique.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		10 to 31 Mar 12 .		
SCS DOPEX0123 (Other SCS cost (a)) **CY2010**	The Other SCS costs included the IT costs.	"Activities" items disclosed in Appendix B of JEN's RIN responses and previous RASs are sourced from SAP, the ERP system that JEN uses to capture its financial and some operational information. The "previous year" amount submitted in the RIN for CY2011 for IT cost disclosed here and adjusted for the following: The IT cost has been deducted from Other SCS costs reported in the regulatory accounts where IT cost was not separately disclosed.	As above.	As above.
SCS DOPEX0124 (Metering cost) **CY2006 – CY2007**	The RASs for CY06 and CY07 were completed on a June financial year end, a legacy process inherited from JEN's prior owner. However, JEN has previously converted this data to calendar years as part of its response to the RINs issued for the previous EDPR. JEN has used those prior RIN responses as the basis for the data disclosure in this RIN.	Underlying monthly or quarterly data, where possible, or pro-rata calculation where not available.	The assumption is that the cost in the activities / networks / internal orders flowed evenly across the period so that prorated costs represent actual cost.	The EDPR submission has already been used by the AER in regulatory decisions. It is therefore best to use a consistent methodology.
ACS DOPEX0118 (IT	IT costs are not captured in the JEN GL directly, but are allocated to JEN from a related party.	Underlying monthly or quarterly data, where possible, or pro-rata calculation where not available, consistent with JEN's response to	The proportion of ACS costs to the total costs for the years 2011 to 2013 is representative of the actual proportions	JEN is not aware of a superior estimation technique.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
cost) **CY2006 – CY2008**	Also, the RASs for CY06 and CY07 were completed on a June financial year end, a legacy process inherited from JEN's prior owner. However, JEN has previously converted this data to calendar years as part of its response to the RINs issued for the previous EDPR. JEN has used those prior RIN responses as the basis for the data disclosure in this RIN. The IT costs in the RAS were in total and not split between SCS and ACS.	the previous EDPR RIN. The average proportion of ACS IT cost to total IT costs for the years CY2011 to CY2013 is used to estimate cost splits between SCS and ACS for 2006-2008.	for each year 2006 to 2008.	
ACS DOPEX0118 (IT cost) **CY2009**	IT costs are not captured in the JEN GL directly, but are allocated to JEN from a related party. The IT costs in the RAS were in total and not split between SCS and ACS.	"Activities" items disclosed in Appendix B of JEN's RIN responses and previous RASs are sourced from SAP, the ERP system that JEN uses to capture its financial and some operational information. The average proportion of ACS IT cost to the total IT cost for the years Calendar Year (**CY**) 2011 to CY2013 is used to estimate cost split between SCS and ACS.	The proportion of ACS costs to the total costs for the years 2011 to 2013 is representative of the actual proportions in the relevant prior year.	As above.
ACS DOPEX0118 (IT cost) **CY2010**	As above.	As above.	As above.	As above.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
ACS DOPEX0125 (Public Lighting) **CY2006 – CY2007**	The RASs for CY06 and CY07 were completed on a June financial year end, a legacy process inherited from JEN's prior owner. However, JEN has previously converted this data to calendar years as part of its response to the RINs issued for the previous EDPR. JEN has used those prior RIN responses as the basis for the data disclosure in this RIN. However, neither the EDPR submission, nor the RAS had a separation of cost between "Maintenance" Public Lighting and "Activity" Public Lighting.	Underlying monthly or quarterly data, where possible, or pro-rata calculation where not available. The costs are collected into activities which align to the Public Lighting category. The average proportion of "Activity" Public Lighting cost to the total Public Lighting cost for the years CY2011 to CY2013 is used to split costs between "Maintenance Public Lighting" and the "activity" Public Lighting.	The assumption is that the cost in the activities / networks / internal orders flowed evenly across the period so that prorated costs represent actual cost. That average "Activity" and "Maintenance" proportions of the total costs over 2011-2013 accurately represent the proportional split over all prior years.	The EDPR submission has already been used by the AER in regulatory decisions. It is therefore best to use a consistent methodology. JEN is not aware of a superior estimation technique for splitting "Activity" and "Maintenance" costs.
ACS DOPEX0125 (Public Lighting) **CY2008 – CY2010**	Neither the EDPR submission, nor the RAS had a separation of cost between "Maintenance" Public Lighting and "Activity" Public Lighting.	Sourced the information from the RAS submissions for the relevant years. The average proportion of "Activity" Public Lighting cost to the total Public Lighting cost for the years CY2011 to CY2013 is used to split costs between "Maintenance Public Lighting" and the "activity" Public Lighting.	That average "Activity" and "Maintenance" proportions of the total costs over 2011-2013 accurately represent the proportional split over all prior years.	JEN is not aware of a superior estimation technique for splitting "Activity" and "Maintenance" costs.
ACS DOPEX0123 (Other SCS cost (a))	The RASs for CY06 and CY07 were completed on a June financial year end, a legacy process inherited from JEN's prior owner. However, JEN has previously converted this data to	Underlying monthly or quarterly data, where possible, or pro-rata calculation where not available. The costs are collected into activities which align to the Other SCS regulatory category.	The assumption is that the cost in the activities / networks / internal orders flowed evenly across the period so that prorated costs represent actual cost. The balance cost left after deducting IT cost and Reserve Feeder costs is Other	The EDPR submission has already been used by the AER in regulatory decisions. It is therefore best to use a consistent methodology. JEN is not aware of a superior

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
CY2006 – CY2007	calendar years as part of its response to the RINs issued for the previous EDPR. JEN has used those prior RIN responses as the basis for the data disclosure in this RIN.	The IT costs and Reserve Feeder costs that were included in this category have been removed.	SCS Cost.	estimation technique for splitting “Activity” and “Maintenance” costs.
ACS DOPEX0123 (Other SCS cost (a)) **CY2008 – CY2009**	The Other SCS costs included the IT costs.	“Activities” items disclosed in Appendix B of JEN’s RIN responses and previous RASs are sourced from SAP, the ERP system that JEN uses to capture its financial and some operational information. The amount is sourced directly from the RAS submitted and adjusted for the following: The IT cost has been deducted from Other SCS costs reported in the regulatory accounts, where IT cost was not separately disclosed. Consistent with JEN’s response to the AER’s EDPR RIN in the last round of price reviews, for years 2009 and 2010, adjustments were made to historical RAS expenditures in the Economic Benchmarking Opex template to ensure a proper reflection of the related party margins applicable for the period 1 Apr 10 to 31 Mar 12 .	The balance cost left after deducting IT Costs is Other SCS Cost.	JEN is not aware of a superior estimation technique.
ACS DOPEX0123	This information is considered to be an estimate as it cannot be directly drawn from JEN’s internal business records.	“Activities” items disclosed in Appendix B of JEN’s RIN responses and previous RASs are sourced from SAP, the ERP system that JEN uses to capture its financial and some	As above.	As above.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
(Other SCS cost (a)) **CY2010**		operational information. The “previous year” amount submitted in the RIN for CY2011 for IT cost disclosed here and adjusted for the following: The IT cost has been deducted from Other SCS costs reported in the regulatory accounts where IT cost was not separately disclosed.		

3.2 OPEX CONSISTENCY

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DOPEX0201 (Opex Network Services) (2006-2010)	DOPEX01 reduced by DOPEX0203 and DOPEX0204	N/A	N/A
DOPEX0201 (Opex Network Services) (2011-2013)	DOPEX01 reduced by DOPEX0203 (of Estimate information) and DOPEX0206 (of Estimate information)	N/A	Estimated costs of connection and estimated costs of transmission connection point planning are included within the total opex disclosed in DOPEX01
DOPEX0202 (Opex metering)	Sum of DOPEX0108 and DOPEX0124	N/A	N/A

Variable	Source and why actual	Methodology	Assumptions
DOPEX0203 (Opex for connection services)	Data extracted from JEN's 2011 annual RIN response submitted to the AER.	Shared costs allocated to the item.	N/A
DOPEX0204	Sum of DOPEX0109 and DOPEX0125	N/A	N/A

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPEX0201 (Opex Network Services) (2006-2010)	This is an estimate since it is a sum of estimates	DOPEX01 reduced by DOPEX0202, DOPEX0203 and DOPEX0204	N/A	N/A
DOPEX0202 (Opex for metering)	This is an estimate since it is a sum of estimates	Sum of DOPEX0124A and DOPEX0108A	N/A	N/A

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPEX0203 (Opex for connection services)	Connection service costs are not captured with a unique cost collector that is directly verifiable within JEN's internal business records for years 2006-12. Thereby the data relating to these variables is considered to be an estimate.	In order to estimate the cost associated with the connection service JEN adopted the following approach: 1. activity cost centres were identified in JEN's operational works program which are related to the provision of fault and emergency services. This included connection service 2. activity cost centres were identified in JEN's operational works program which are directly related to the provision of connection services for the period Apr'12 to Dec'13. This included fault & emergency service. 3. these costs were then divided by the total cost of fault & emergency services to derive estimated proportion of connection cost within fault and emergency cost. 4. the cost for fault & emergency was multiplied by this proportion to derive the connections cost for the periods till March'12.	The proportion for connection services within fault & emergency services from Apr'12 to Dec'13 represents the proportional split for all years.	This is JEN's best estimate because it is underpinned by as much 'actual information' as possible. The only element estimated was the proportion of connection activities that contribute to the cost for faults. This was calculated as the average obtained from activity costs for CY13 and 9 months of CY12. Furthermore, JEN is not aware of a superior estimation technique.
DOPEX0204	This is an estimate since it is a sum of estimates	Sum of DOPEX0109 and DOPEX0125	N/A	N/A

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPEX0206 (opex for transmission connection point planning)	This information is considered to be an estimate as it cannot be directly drawn from JEN's internal business records. Therefore JEN's engineers provided their best estimate of the proportion of costs from various activities which relate to this service.	The engineers provided their best estimate of the manhours required per annum for this activity. This was multiplied by the average cost per engineer in nominal dollars.	The average salary and oncosts of an engineer have been assumed. The average time spent by the engineer has been assumed. The average increase in cost of engineer is assumed.	JEN is not aware of a superior estimation technique.

JEN has blacked out cells in 3.2.1 opex consistency as JEN has made no material changes (over the course of the back cast time series) to its:

- Cost allocation approach, or
- Basis of preparation for its regulatory accounting statements, or
- Annual reporting requirements as they apply to information contained in ~~disclosure as it aligns with~~ table 3.2.2

3.3 PROVISIONS

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
All variables (DOPEX0301 – DOPEX0312)	JEN's accounting system	The data is considered actual as it is extracted from the relevant General Ledger. JEN has two provisions, i.e. Provision for Doubtful Debts and Claims/Compensation. When JEN incurs actual expenses in the form of Bad Debts by its customers, these are posted into the Profit and Loss (**P&L**) statement. JEN adjusts these provisions in accordance with its internal policies to ensure that the correct provisions are disclosed in its accounts. Due to the nature of provisions, expenses incurred are OPEX in nature. There is no impact to CAPEX, therefore no disclosure in the CAPEX subsections of Table 3.3	N/A

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
All variables DOPEX0313 to DOPEX0324 Claims from customers	JEN is unable to identify actual payments made to customers in its legacy systems, so it carries these amounts in variable DOPEX0315	As the payments are not clearly identified in JEN's cost centres, this provision increases or decreases against a database where the customer service manager tracks the claims. JEN believes that the amounts paid will naturally be in included in the variable "used (that is, incurred and charged against the provision) during the period"	Amounts paid are included in the variable DOPEX0315	JEN is not aware of a superior estimation technique.

Attachment 4 provides a reconciliation of the operating and maintenance expenditure in the RAS/annual RIN to that provided within this economic benchmarking RIN.

3.4 OPEX FOR HIGH VOLTAGE CUSTOMERS

ACTUAL INFORMATION

No actual information is provided.

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPEX0401 (high voltage customers)	This is an estimate as the costs are not incurred by JEN.	The engineering team provided an estimate of activities and their costs that may have been incurred over a bl ock of 4 years in 2013 nominal dollars. This cost is divided by 4 to arrive at an estimated cost per annum in 2013 nominal dollars. This estimated annual cost is back cast using a deflation factor.	The costs are incurred evenly across the years as the volume of high voltage customers is stable and work involved is cyclical. Customers would be at different stages of the cycle.	JEN is not aware of a superior estimation technique.

4. ASSETS (RAB) WORKSHEET

4.1 REGULATORY ASSET BASE VALUES

ACTUAL INFORMATION

No actual information is provided.

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DRAB0101 – DRAB0107	These variables are estimated as they are the summation of a series of estimated inputs.	Table 4.1 is the summation of the individual asset categories in table 4.2	None	This is JEN's best estimate as these variables are simply the summation of a series of JEN's best estimates of individual asset categories in table 4.2

4.2 ASSET VALUE ROLL FORWARD

ACTUAL INFORMATION

No actual information is provided.

ESTIMATED INFORMATION

For more detail relating to the variables explained below in section 4.2 Asset value roll forward and section 4.3 Total disaggregated RAB values, please refer to **Attachment 3—JEN EBT allocation model**.

Explain why the variable is estimated and why actual information could not be provided

JEN notes that the information relating to the regulatory asset base are estimates rather than actuals.

The variables are estimates rather than actual information for three main reasons:

1. The information relating to the RAB does not meet the AER's definition of actual because this information is not recorded within JEN's financial system and cannot be reconciled to it. JEN does not report this information in the normal course of business. As such, this information is not ~~is~~ consistent with the AER's definition of 'actual~~estimates~~' information.
2. JEN was unable to directly allocate the asset categories within the AER's approved RAB for JEN (hereafter referred to as **regulatory categories**) to the AER's economic benchmarking asset categories (hereafter referred to as **EBT categories**). Therefore, an allocation methodology was applied. Also note that JEN does not capture RAB data within its financial systems.
3. The AER has never approved a network services RAB and therefore it had to be estimated.

The sections below provide further detail.

Allocation of regulatory categories to EBT categories

The regulatory categories that were able to be directly allocated to EBT categories are set out in table A below.

Table A. Direct allocation of regulatory categories to EBT categories

Regulatory category	EBT category
Standard metering	Meters
Public lighting	Other assets with long lives
SCADA/Network control	Other assets with short lives

Regulatory category	EBT category
Non-network general assets - IT	Other assets with short lives

The regulatory categories that were allocated to a group of EBT categories are set out in table B below.

Table B. Allocation of regulatory categories to group of EBT categories

Regulatory category	Group of EBT categories
Sub-transmission	Overhead network assets 33kV and above (wires and towers / poles etc.)
	Underground network assets 33kV and above (cables, ducts etc.)
	Zone substations and transformers
Distribution system assets	Overhead network assets less than 33kV (wires and poles)
	Underground network assets less than 33kV (cables)
	Distribution substations including transformers
Non-network general assets - Other	Other assets with long lives
	Other assets with short lives

JEN does not capture data for easements. JEN did not report any values for easements and were intentionally left blank in the template.

Explain the basis upon which the estimate was made and the methodology used

JEN rolled forward its SCS RAB by applying the AER's RAB framework. For the regulatory years 2006 to 2010, the SCS RAB reconciles back to the AER's approved roll-forward model (**RFM**).[1] For the regulatory years 2011 to 2013, the AER has not yet approved JEN's RAB as this review process will occur during the next EDPR.

To roll-forward its SCS RAB for the most recent three years, JEN applied the AER's final decision relating to the RFM to be used by the distribution network service providers (**DNSPs**).[2]

In doing so, two adjustments were made to the RFM:

1. Adjustment made within the "*total actual RAB roll forward*" sheet to take into account the difference between forecast capex and actual capex for the regulatory year 2005 as well as the return on the difference.
2. Adjustment made within the "*Input*" sheet to amend the CPI index (one year lagged) to ensure the nominal capex spent in the regulatory year 2011 is deflated to real 2009-10 dollars using an index of 1.0279 (using a year on year Dec-quarter inflation of 2.79%) instead of 1.26%.

JEN rolled forward its ACS RAB in accordance to the AER's approved public lighting model

JEN's ACS RAB is made up of public lighting assets post 2001 only. The public lighting assets prior to 2001 are within the SCS RAB and are excluded from the NS RAB. To roll-forward its ACS RAB, JEN has applied the AER's final decision on its public lighting model.[3]

In doing so, two adjustments were made:

1. Adjustment made to replace forecast capex, capital contributions and asset disposals for the regulatory years 2010 to 2013, with actual data.
2. Adjustment made to replace forecast inflation with actual data.

[1] *AER, Jemena Electricity Networks (Victoria) Ltd, distribution determination, Pursuant to Orders of the Australian Competition Tribunal in Application by United Energy Distribution Pty Limited (No 2) [2012] ACompT 8, September 2012.*

[2] *AER, electricity distribution network service providers, roll forward model, June 2008.*

[3] *AER, Jemena Electricity Networks (Victoria) Ltd, distribution determination, Pursuant to Orders of the Australian Competition Tribunal in Application by United Energy Distribution Pty Limited (No 2) [2012] ACompT 8, September 2012*

This means that the ACS RAB reconciles back to the AER's approved RFM model for the regulatory years 2006 to 2009, and is consistent with the AER's methodology to roll the ACS RAB to 2013 using actual data instead of forecast. No adjustment was made for the compound return on the difference between actual and forecast net capex in 2010.

JEN adopted the AER's standard approach to disaggregate its RAB

JEN disaggregated its RAB into the EBT categories using the AER's prescribed standard approach, where JEN is required to allocate its RAB, in direct proportion to the relevant EBT category's share of either:

- total estimated depreciated replacement cost (**DRC**) for 2013, or
- total book value for the regulatory year 2013.

The DRC was used to estimate the following EBT categories:

- Overhead network assets less than 33kV (wires and poles)
- Underground network assets less than 33kV (cables)
- Distribution substations including transformers
- Overhead network assets 33kV and above (wires and towers / poles etc.)
- Underground network assets 33kV and above (cables, ducts etc.)
- Zone substations and transformers.

The book value within JEN's statutory asset register has been used to estimate the following EBT categories:

- Other assets with long lives
- Other assets with short lives.

The EBT category 'meters' was populated as a direct allocation from the RAB category 'standard metering'.

JEN has used estimated depreciated replacement costs to allocate its network assets

Consistent with the AER instructions, the DRC for each EBT Category was estimated by the following formula:

> ***DRC*** *= Estimated weighted average unit rate replacement costs x physical asset data x weighted average remaining asset lives (existing assets) / weighted average service lives (existing assets), where:*

- *The estimated weighted average unit rate replacement costs were estimated using best endeavours, based on most recent project estimates. Due to lack of information, the project sample includes both (a) partially completed and (b) completed projects. The projects within the sample were assigned physical characteristics such as (a) line length in kms and (b) capacity in MVA, based on engineering judgement. The estimated weighted average unit rate is then calculated as the project cost estimates ($) / length line (kms) x capacity (MVA). Importantly, JEN assumed that the same unit replacement costs for both overhead and underground network assets 33kV.*
- *Physical asset data is sourced from RIN sheet 6 (Physical assets).*
- *The weighted average remaining asset lives (existing assets) are sourced from table 4.4.2 of RIN sheet 4 (RAB assets).*
- *The weighted average service lives (existing assets) are based on the lives in table 4.4.1 of RIN sheet 4 (RAB assets), but amended to reflect the service lives of existing assets rather than new assets installed in the relevant year.*

The estimated DRCs for the regulatory year 2013 were used to allocate the RAB categories to EBT categories for the whole period (2006 to 2013), as per the AER's instructions.

Table C sets out the DRC that is calculated by applying the prescribed DRC formula. The estimated DRC is explicitly used to derive the percentage allocation fo the RAB, and is not indicative of the actual network replacement costs. **Table D** sets out the allocation of RAB categories to EBT Categories based on 2013 DRC.

Table C. 2013 depreciated replacement costs by EBT category

EBT Category	Unit	CY13
Overhead network assets less than 33kV (wires and poles)	$\$000/km^2/MVA$	9,152
Underground network assets less than 33kV (cables)	$\$000/km^2/MVA$	659
Distribution substations including transformers	$\$000/km/MVA^2$	495
Overhead network assets 33kV and above (wires and towers / poles etc.)	$\$000/km^2/MVA$	190

Underground network assets 33kV and above (cables, ducts etc.)	$000/km^2/MVA	7
Zone substations and transformers	$000/km/MVA^2	178

Table D. Percentage allocations of RAB categories to EBT categories based on 2013 DRC

RAB category	Allocation to EBT categories	
Sub transmission	Overhead network assets 33kV and above (wires and towers / poles etc.)	50.56%
	Underground network assets 33kV and above (cables, ducts etc.)	1.94%
	Zone substations and transformers	47.50%
	Total	**100.00%**
Distribution system assets	Overhead network assets less than 33kV (wires and poles)	88.81%
	Underground network assets less than 33kV (cables)	6.39%
	Distribution substations including transformers	4.80%
	Total	**100.00%**

JEN used the relative share of book value to allocate its non-network assets

JEN mapped each regulatory category to an EBT category. The relative share of book value was only used to allocate the regulatory category 'non-network general assets – other' to the two EBT categories 'other assets with short lives' and 'other assets with long lives'.

Table E sets out the resulting allocation of 2013 book value.

Table E. Percentage allocations of regulatory categories to EBT categories based on 2013 book value

Regulatory category	Allocation to EBT categories	
Non-network general assets - Other	Other assets with long lives	6.93%
	Other assets with short lives	93.07%

Regulatory category	Allocation to EBT categories	
	Total	**100.00%**

JEN estimated a network services RAB

The AER approved a SCS and ACS RAB for JEN during the 2010 electricity distribution price review, but did not approve network services (**NS**) or fee & quote based services (**FQ**) RABs.

JEN notes the AER's guidance that the NS RAB is a subset of the SCS RAB. The NS RAB was estimated by removing any portion of assets from the SCS RAB, which relate to the provision of:

- connection services
- standard metering
- public lighting
- fee & quoted based services.

JEN faced difficulties identifying assets related to connection services because—unlike standard metering and public lighting—JEN does not have a separate regulatory category for connection services assets.

Faced with this difficulty, JEN estimated the NS RAB by:

- step 1—estimating the proportion of total capital contributions related to connection services over 2010 to 2013, where data was available
- step 2—multiplying gross (net) demand connection capex over 2006 to 2013 by this proportion to estimate the gross (net) capex related to connection services
- step 3—using this net capex to estimate the share of the opening 2006 RAB related to connections.

No assets were deducted for fee and quote based services because the AER did not approve any FQ RAB.

Further detail follows.

Step 1. The approach starts with total capital contributions for the regulatory years 2010 to 2013 by activity (e.g. medium density housing, dual and multiple occupancy, business supply projects, etc.). Because JEN does not have a connection services RAB, it assumed that all contributions relating to business supply projects and low density & small business supplies <10kvA are associated with connection services.

This represents an average of 43% over the four years, calculated using the following:

Portion of connection services = (CC1 + CC2) / total capital contributions, where:

> ***CC1 =*** *capital contributions relating to business supply projects*
>
> ***CC2 =*** *capital contributions relating to low density & small business supplies <10kvA.*

Step 2. To then determine the gross capex and capital contributions amounts (relating to connection services) for the whole period (2006 to 2013), JEN applied the above percentage to the gross demand connection capex and total contributions to the regulatory years 2006 to 2009.

Step 3. JEN also identified an estimated portion of the opening distribution system assets RAB (2006), that relates to connection services based on the relative proportion of net connection services capex to net distribution system assets capex for the whole period.

The formula used is set out below:

Opening 2006 RAB (connection services) = Cp:Dp x opening 2006 RAB, where:

> ***Cp:Dp*** = *Ratio of net connection services capex to ratio of net distribution system assets capex*
>
> ***Net capex*** = *gross capex less capital contributions*
>
> ***Opening 2006 RAB*** = *AER approved 2006 opening RAB for distribution system assets.*

The identified opening connection services RAB was then rolled-forward in accordance with the AER's RAB framework, using connection services capex, customer contributions and asset disposals. The regulatory depreciation for the connection services net capex was assumed to be a portion (calculated above) of the regulatory depreciation for distribution system assets.

Explain the assumptions made when applying the chosen methodology

JEN interpreted the AER's guidance to use DRC for the regulatory year 2013 retrospectively

- When calculating depreciated replacement costs, JEN interprets the AER's instruction "*where disaggregation is required for the whole period then this will be the 2013 regulatory year*" to mean that the DRC estimates for the regulatory year 2013 are used to allocate the regulatory categories to the network-related EBT categories for the regulatory years 2006 to 2013. The same approach was used to allocate regulatory categories to non network-related EBT categories based book values.
- When calculating the DRC estimates, JEN applied the weighted average service lives of *existing assets*, rather than *new assets*.

JEN made assumptions to estimate a notional NS RAB

- The 2006 opening RAB for connection services was assumed to equal the historical (2006 to 2013) cumulative share of connection related net capex, multiplied by the opening RAB of distribution system assets.
- The proportion of capital contributions related to connection services over 2006 to 2009 equals the average proportion over 2010 to 2013.
- The activities that relate to connection services are assumed to be business supply projects and low density & small business projects <10kvA.
- The proportion of gross connection services capex over 2006 to 2013 related to connection services is the same as the equivalent proportion for capital contributions over this period.
- RAB escalation and straight line depreciation for connection services equals the equivalent value for the SCS RAB multiplied by the share of the opening SCS RAB related to connection services.

JEN made other general assumptions to estimate the RABs

- All information is presented in nominal dollars.
- All information is presented to the nearest thousand ($000), rounded to the nearest dollar.
- Straight line depreciation and regulatory depreciation are expressed as positive values.
- Actual additions are assumed to equal gross capex less customer contributions.

- The same allocation percentages were used to allocate RAB categories to EBT categories for each of the RABs (SCS, NS, ACS).
- The AER approved adjustments to the SCS RAB in the regulatory year 2010 (accounting for the difference between forecast and actual capex incurred in the regulatory year 2005) has been incorporated as an addition to the closing asset value in that year. This explains why the closing value does not equal the opening value plus actual additions less disposals less regulatory depreciation in the regulatory year 2010.

The assets that were added to the AER approved ACS RAB in 2010 was incorporated as an addition to the closing asset value in that year. This explains why the closing value does not equal the opening value plus actual additions less disposals less regulatory depreciation in the regulatory year 2010.

Explain why the estimate is JEN's best estimate given the information sought

JEN uses, where possible, data that are within its financial system, AER approved data and its best endeavours when estimating the relevant RABs.

JEN's best estimate follows, as close as possible, the AER's explanatory statement, instruction and definition document or the AER's preferred methodology for rolling forward RABs, such as:

- using ABS data to estimate actual CPI
- applying the RAB framework to roll-forward its RAB, and
- adopting the standard allocation approach to disaggregate its RAB.

4.3 TOTAL DISAGGREGATED RAB ASSET VALUES

ACTUAL INFORMATION

No actual information is provided.

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DRAB1201 - 1210	JEN considers these variables to be estimates as they are a function of estimated variables.	These variables are the summation of variables DRAB0201 – DRAB 1107	None	Refer to section 4.2
DRAB13	Refer to page 38 above 'JEN made assumptions to estimate a network services RAB'	Refer to page 38 above 'JEN made assumptions to estimate a network services RAB'	Refer to page 38 above 'JEN made assumptions to estimate a network services RAB'	Refer to page 38 above 'JEN made assumptions to estimate a network services RAB'

4.4 ASSET LIVES

ACTUAL INFORMATION

1. Assets applicable to ACS are public lightning and street lights only. These apply to the long asset lives category (DRAB1408, DRAB1508).

2. All assets for SCS have the same estimated service life for network services because connection fees in SCS does not affect the estimated average life of the assets, except for DRAB1401, DRAB 1402, DRAB1501, DRAB1502. Services assets apply to the category of DRAB1401, DRAB1402, DRAB 1501, DRAB1502 and are only included in SCS Section.

Variable	Source and why actual	Methodology	Assumptions
DRAB1401–DRAB1406 for 2011 to 2013	Asset Age Profile for its respective year JEN considers this information to be actual as it is captured in the following internal business records: **Asset Age Profile 2011**: RIN A 2011 Non-Financial – Section 3. Asset	1. Refer to Economic Benchmarking RIN – Instructions and Definitions 2. Refer to **Attachment 1** Procedure 4.4.1 Asset Lives – Estimated service life of new assets FEB 2014 3. JEN PR 0114 – Methodology to allocate unknowns	1. Assumption stated in the methodology document (refer to document JEN PR 0114, JEN PR 0506) 2. Assumption stated in the methodology document (refer to document JEN PR 0504) 3. It is assumed that the dollar capture for its respective year is JEN's total expenditure for

Variable	Source and why actual	Methodology	Assumptions
	Installation Methodology & Work Instruction can be found in: JEN PR 0114, JEN PR 0506. Data is sourced (or extracted) using internal IT Systems: SAP, BRIO, GIS. All extracted data is stored in the internal document management system - ECMS.**Asset Age Profile 2012**: RIN A 2012 Non-Financial – Section 3. Asset Installation Methodology & Work Instruction can be found in: JEN PR 0114, JEN PR 0506. Data is sourced (or extracted) using internal IT Systems: SAP, BRIO, GIS. All extracted data is stored in the internal document management system - ECMS. **Asset Age Profile 2013**: BRIO, Geospatial Information System (**GIS**), SAP (same methodology as RIN 2011, RIN 2012). Methodology & Work Instruction can be found in: JEN PR 0114, JEN PR 0506. Data is sourced (or extracted) using internal IT Systems: SAP, BRIO, GIS. All extracted data is stored in the internal document management system - ECMS. Assigned asset age: Assigned asset age has been derived in consultation with relevant technical experts at	4. JEN PR 0506 – RIN Asset Installation Reporting Procedure 5. JEN PR 0504 – AER Asset Replacement Unit Cost Reporting Procedure	replacing assets (in today's dollar) 4. Unit Cost 2013: Assumption stated in the methodology document (refer to document JEN PR 0504) - Unit cost for few assets can't be obtained from SAP due to the nature of the project and also due to time constraint. The approach taken for 2013 was based on unit cost 2012 + CPI (3%).

Variable	Source and why actual	Methodology	Assumptions
	Jemena. **Unit Cost for its respective year** Procedure and methodology can be found in JEN PR 0504 For 2011: RIN A 2011 For 2012: RIN A 2012 For 2013: SAP (same methodology as RIN 2011, RIN 2012) Total replacement expenditure by asset class for its respective year is obtained from JEN's finance team.		
DRAB1501-DRAB1506) for 2011 to 2013	See above.	1. Same as above as section (4.4.1) Refer to Attachment 2 Procedure 4.4.2 Asset Lives – Estimated residual service life FEB 2014	See above.

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DRAB1401 – DRAB 1406 for 2006 – 2010	Age Profile of all JEN Assets are not captured for the year 2006 – 2010 (as there was no RIN A submission in that period). JEN's systems only store current year's data.	From the data of 2011, 2012, 2013 (all actuals) average was obtained in finding proportion of each asset. The average proportion of each asset is used against the total replacement expenditure for its respective year to find the weighted average life. Weighted average life is calculated as per	The total replacement expenditure from the "Asset Class Dollar Cost per year sheet" is assumed to be how much JEN spent to replace its assets for its respective year.	This would be JEN's best estimate because JEN uses its total replacement expenditure for its respective year against the average data obtained from actuals.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		the formula stated in the Economic Benchmarking RIN – Instructions and Definitions for JEN (page 27).		
DRAB1501 – DRAB 1506 for 2006 - 2010	Age Profile of all JEN Assets are not captured for the year 2006 – 2010 (as there was no RIN A submission in that period). JEN's systems only store current year's data.	From the data of 2011, 2012, 2013 (all actuals) average was obtained in finding proportion of each asset. The average proportion of each asset is used against the total replacement expenditure for its respective year to find the weighted average life. As for residual lives, the asset lives are varied from 2011 – 2013 (actuals), therefore average is also obtained for each asset's lives. Weighted average life is calculated as per the formula stated in the Economic Benchmarking RIN – Instructions and Definitions for JEN (page 27).	The total replacement expenditure from the "Asset Class Dollar Cost per year sheet" is assumed to be how much JEN spent to replace its assets up until its respective year.	This would be JEN's best estimate because JEN uses its total replacement expenditure up to its respective year against the average data obtained from actuals.
DRAB1407 – DRAB 1409, DRAB1507 – DRAB 1509	The variables are estimates rather than actual information for two main reasons: JEN was unable to directly allocate the asset categories within the AER's approved RAB for JEN (hereafter referred to as regulatory categories) to the AER's economic benchmarking asset categories (hereafter referred to as EBT categories). Therefore, an allocation methodology was applied.	Step 1 – JEN has calculated implied remaining lives based on the AER's approved data JEN has initially rolled forward its SCS RAB by applying the AER's RAB framework. This is explained in detail in section 4.1 and 4.2 above. To estimate an implied remaining life for each regulatory category, JEN has used the following formula: **Implied estimated remaining life** = opening RAB / current year regulatory	All information is presented in nearest whole unit. Regulatory depreciation is equal to straight line depreciation – RAB indexation. The estimated standard and remaining service lives are assumed to be the same as economic lives. All information is presented in nearest whole unit. Regulatory depreciation is equal to straight line depreciation less RAB	The AER has approved JEN's RAB, making up the five regulatory categories, namely: - Sub transmission - Distribution system assets - SCADA/network control - Non network-IT - Non network-other The first two categories relate to network assets, and the asset lives have been estimated using a mixture of

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	2. JEN currently has a regulatory category 'non network-other', which includes both short lives and long lives assets. In order to disaggregate this category, it requires an estimation methodology.	depreciation, where: *Regulatory depreciation = straight line depreciation - RAB indexation* Step 2 – JEN determined the mix of short life to long life assets within its statutory asset base JEN mapped all its individual financial categories within its statutory asset base to the AER's EBT categories. This mapping highlights that the mix of short life to long life assets is approximately 93% and 7% respectively. This mix is assumed to apply for the 2006 to 2013 period. Step 3 – JEN calculated weighted average residual lives JEN assumed that the ratio of lives for short life assets to long life assets is 0.25. For example, a typical long-life asset is freehold building, which typically has a 40 year life span. A short life asset is then assumed to have an average of 10 year life span based on the above assumption. JEN used the implied remaining life for 'non network-other' asset from the AER approved data (step 1) to calculate a notional remaining life profile for both short life and long life assets. The formula is set out below: **Remaining life (long life asset)** = Implied remaining life (AER) / (Lp + S:L x Sp), where:	indexation. The estimated standard and remaining *service* lives are assumed to be the same as the estimate standard and remaining *economic* lives, respectively. The ratio of lives for short to long life assets is 0.25. The closing RAB is used to derive the relative weights to calculate a weighted average remaining life for '"Other" assets with short lives'. '"Other" assets with short lives' include the regulatory categories 'SCADA/network control', 'non network-IT' and 'non network-other'.	engineering judgement, statutory asset register and year on year capex additions. For the non network assets, especially with non network-other assets, where they include both short and long life assets, JEN developed a methodology to (a) meet the AER's definition of a short life asset being one which has an asset life of 10 years or less, and (b) support a correlation between the RAB build up and the asset lives. JEN considers that this approach is its best estimate as it used a mixture of information source, ranging from statutory asset register to AER's approved data, while meeting the two objectives above. Importantly, JEN notes that this approach results in the standard service lives for "Other" assets with short lives to be greater than 10 years for the regulatory years 2011 to 2013. The reason is because the AER approved a standard life of 19.9 years for the period 2011 to 2015 compared to 9.2

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		Lp = portion of long life assets, *S:L = assumed ratio of short life to long life assets, and* *Sp = portion of short life assets.* By applying the asset mix calculated from step 2, JEN has estimated a weighted average residual life profile for both '"Other" assets with long lives' and '"Other" assets with short lives', by using the closing RAB as the driver to estimate the relative weights. The formula used to derive the weighted average remaining life for short life assets is: **Weighted remaining life (short life asset)** = (W1 x L1) + (W2 x L2) + (W3 x L3), where: *W1 & L1 = relative weight and implied remaining life for SCADA/network control assets* *W2 & L2 = relative weight and implied remaining life for non network-IT assets* *W3 & L3 = relative weight and implied remaining life for non network-other assets* JEN did not have to calculate a weighted remaining life for long life assets because the regulatory category 'non network-other' only includes one EBT category, namely '"Other" assets with long lives'. This is calculated in the formula above. Step 4 – JEN applied the same methodology to estimate standard service lives To estimate the standard service lives, JEN		years in the period 2006 to 2010 (approved by ESC).

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		applied the same methodology. Instead of using the implied remaining lives, JEN used the AER's approved standard lives for the regulatory years 2006 to 2010 and 2011 to 2013. The formula is set out below: **Standard service life (short life asset) =** (W1 x L1) + (W2 x L2) + (W3 x L3), where: *W1 & L1 = relative weight and standard service life for SCADA/network control assets* *W2 & L2 = relative weight and standard service life for non network-IT assets* *W3 & L3 = relative weight and standard service life for non network-other assets*		
Network services and alternative control services DRAB 1401-DRAB1409 DRAB1501-1509	JEN has intentionally left variables DRAB1407 and DRAB1507 blank. This is consistent with the AER's explanatory statement where network services are defined as a subset of standard control services—i.e. network services excludes metering, connection services, public lighting and fee based and quoted services. Consequently, JEN has excluded metering asset service and residual lives from the network services section and included asset service and residual lives for public lighting within the ACS section (under the category "Other" assets with long lives—DRAB1508). JEN has also not reported any asset service and residual asset lives for the following variables (DRAB1401-DRAB1406, DRAB1409 and DRAB1501-DRAB1506, DRAB1509) within the ACS section because the only asset that resides within JEN's ACS RAB is public lighting.			

5. OPERATIONAL DATA WORKSHEET

5.1 ENERGY DELIVERY

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DOPED01	The data is sourced from JEN's two billing systems. The data is then captured in the LCYYYY.xls on a monthly basis and is summed in worksheet Year to date. The information obtained in the reports is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in the LCYYYY.xls on a monthly basis and is summed in worksheet Year to date.	N/A
DOPED0201 – DOPED0206	As above	As above	N/A
DOPED0501-DOPED0505	As above	As above	N/A

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPED0301 - DOPED0304	The TNSP data obtained by JEN is a monthly value; this value is	The estimate is made upon the following basis:	The estimate is based on the assumption that the proportion (percentage) of peak	It is JEN's best estimate as we believe it is reasonable to

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	not split between peak, shoulder or off peak energy. For this reason it is only the allocation between peak and off peak that is an estimate and not the total value.	Total TNSP data for each calendar year is allocated to the following peak and off peak percentages. 2006 – 2013: Total energy delivered (excluding tariffs A100, A200, and A10x shoulder period only) Total Peak energy (excluding A100 and A200) Total Off Peak Energy Peak percentage is equal to; Total peak energy for each calendar year / total energy delivered for each calendar year. Off Peak percentage is equal to; Total Off peak energy for each calendar year / total energy delivered for each calendar year. DNSP is actual data obtained from monthly invoices sent / received to other distribution businesses. This information is split between peak and off peak. The TNSP peak energy and DNSP peak energy are added to obtain total peak	and off peak Transmission Network Service Provider (**TNSP**) energy is the same as the energy delivered as reported to the business.	assume that JEN's output energy peak and off peak profile should correlate with the input energy profile—which is the energy received from TNSP.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		energy. The TNSP off peak energy and DNSP off peak energy are added to obtain total off peak energy.		
DOPED0401 to DOPED0403	JEN does not record data for variables (DOPED0401- DOPED0403) . The energy received from Embedded Generation on an accumulation basis is provided under the variable DOPED0404.			
DOPED0404	JEN considers this information an estimate as energy received into JEN from embedded generation is available in financial year data, however not by calendar year. JEN had to therefore calendarise the information.	The data is derived from interval energy meter readings which are extracted from the JEN system called Interval Meter Store (**IMS**). The calendar year data is derived by taking the average of 2 consecutive financial year data entries. For example energy received from embedded generation in CY 2006 is calculated as the average of energy received from embedded generation in FY 2005/06 and 2006/07. $$EG_{CY} = \frac{EG_{(CY-1)/CY} + EG_{CY/(CY+1)}}{2}$$ where: EG = Embedded generation in GWh CY = Calendar year $EG_{(CY-1)/CY}\ or\ EG_{CY/(CY+1)}$ = Financial year embedded generation data in GWh.	The Financial Year (**FY**) 2013/14 data (used to derive CY 2013 year data) is forecast as the average of the data for 2006/07 to 2012/13. The data is generation data only, it does not include the energy consumed by embedded generation. The data provided is the energy received from non-residential embedded generation with capacity greater than 1 MW on an accumulation basis. The embedded generators included are: APM Fairfield (installed 1991) Austin Hospital (installed 1991) Bioscience Research Centre (Installed 2011) EDL – Bolinda Landfill (installed 1993) EDL – Brooklyn Landfill (installed 2002) LaTrobe University (installed early 1990s) Preston Mini Hydro (installed 2008) Visy (installed 2012)	The estimate is reasonable given the availability of data and as JEN is not aware of a superior estimation technique.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
			Embedded generators excluded are: Somerton Power Station (installed 2002)	

5.2 CUSTOMER NUMBERS

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DOPCN0105	Jemena's Customer Information System (**CIS**) and SAP ISU systems are the source of actual data for customer numbers. The data is extracted from the system by raising Cognos reports.	The methodology used is to extract the customer numbers from the CIS and SAP ISU systems and to add them together to provide the total customer numbers. CIS provides the number of customers with non-smart meters and the number of unmetered customers. SAP ISU provides the number of customers with a smart meter.	No assumptions have been made.

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPCN0101 - DOPCN0104, DOPCN0106	Although the total number of customers is known and can be provided, the actual split of the customer numbers by tariff type is not specifically recorded.	The methodology used was to multiply the total customer numbers by the percentage split of tariff type categories.	The percentage split between the categories DOPCN0101 - DOPCN0104, DOPCN0106 is based on the average number of active National Meter Identifiers (**NMI's**) as reported during the relevant Regulatory year. The number of deenergised NMIs has been evenly distributed according to the same proportion as active NMIs.	JEN's estimate is considered to be the best estimate as it uses the actual total number of customers and the best estimate of the customer split by tariff type.
DOPCN0201 - DOPCN0203	JEN's CIS and SAP ISU systems are the source of actual data for customer numbers. The definition of rural short and urban feeders has been used to determine the categorisation of each feeder. The GIS is a live model of the network and represents the network at the current point in time. This means that a snap shot of the GIS network model or data is not made at the end of each year. Therefore it is not possible to report the number of customers for rural and urban feeders historically.	The methodology that JEN has applied is based on the definition of short rural and urban feeders that was in place in the specific year. JEN has determined the number of customers on rural and urban feeders using a ratio of customer numbers. The customer numbers excludes unmetered customers.	No assumptions have been made in providing this information.	JEN's estimate is considered to be the best estimate as it uses the actual total number of customers and the ratio of customers on rural and urban feeders. JEN is not aware of a superior estimation technique.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPCN0201and DOPCN0204	JEN has no customers of this type on its network and is therefore not applicable.			

5.3 SYSTEM DEMAND

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DOPSD0101	JEN considers this information is actual as it can be directly drawn from the internal business records. The information is obtained from historical SCADA metering data. Throughout the JEN network there is a significant number of measurements (voltage and current), predominantly at JEN zone sub-stations, being provided to the Real Time Systems. All historical SCADA data (2008 onwards) can be interrogated using PI (user interface developed by OSIsoft) JEN has referred to the following reports to obtain the data. EDPR RIN 2010 Revised template – worksheet Demand (6.3) and JEN maximum demand forecast excel spread sheet model Note: PI is the proprietary software developed by OSIsoft. The historical SCADA data can be interrogated using PI.	This is derived from metered actual zone substation data, adjusted for abnormal changes—un-anticipated temporary load changes due to transfers, interruption caused for network contingencies—but excludes any embedded generation. $$MD_x = \sum_{1}^{n} MD_{ZSSn}$$ Where MD_x = non-coincident summed raw unadjusted annual maximum demand at ZSS level (MW) in year x n = number of JEN zone substations MD_{ZSSn} = non-coincident raw unadjusted annual maximum demand at ZSS n (Mega Watts (**MW**)) in year x	The data includes JEN owned zone substations only i.e it does not include the customer substation and other DNSP owned zone substations.

<table>
<tr><th>Variable</th><th>Source and why actual</th><th>Methodology</th><th>Assumptions</th></tr>
<tr><td>DOPSD0104</td><td>JEN considers this information is actual as it can be directly drawn from the internal business records.

The source of actual information is PI system which stores the historical SCADA metering data.

JEN has referred to the following reports to obtain the data.

EDPR RIN 2010 Revised template – worksheet Demand (6.3) and JEN maximum demand forecast excel spread sheet model</td><td>The historic coincident maximum demand data for each zone substation is extracted from PI at the time of coincident system peak demand at the transmission network connection points each year and provided the summation.

The approach explained above (to retrieve the data from PI) was adopted for information from 2008-2013.

$$MD_x = \sum_{1}^{n} MD_{ZSSnt}$$

Where

MD_x = coincident summated raw system annual maximum demand at Zone Substation level (MW) in year x

n = number of JEN Zone Substations

t = time of system coincident maximum demand as determined at the transmission connection point level.

MD_{ZSSnt} = coincident raw unadjusted annual maximum demand at Zone Substation n (MW) in year x at time t.</td><td>JEN assumed that the summation of actual raw demands for the zone substation is the greatest at the time of coincident peak system demand.

Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible.</td></tr>
</table>

Variable	Source and why actual	Methodology	Assumptions
DOPSD0107	Data source 2006-2009 - EDPR 2010 Revised RIN template – worksheet Demand (6.3) Table 16 - Historical non coincident unadjusted/raw maximum demand measured at the transmission network connection points. JEN considers this information is actual as it can be directly drawn from the internal business records listed above.	This is derived from metered actual (transmission network connection point 15 min- data excluding any embedded generation adjustment. $$MD_x = \sum_{1}^{n} MD_{TCPn}$$ Where MD_x = non-coincident summed raw system annual maximum demand at Transmission Connection Point level (MW) in year x n = number of JEN Transmission Connection Points MD_{TCPn} = non-coincident raw unadjusted annual maximum demand at Transmission Connection Point n (MW) in year x	This includes JEN load flowing on JEN's subtransmission network only. E.g. Thomastown Terminal (**TT**) station load is excluded as TT load is supplied by non-JEN subtransmission lines.

Variable	Source and why actual	Methodology	Assumptions
DOPSD0110	Supporting data source 2006-2009 EDPR 2010 Revised RIN template – worksheet Demand (6.3) Table 9 - Historical system coincident unadjusted/raw maximum demand measured at the transmission network connection points. JEN considers this information is actual as it can be directly drawn from the internal business records listed above.	Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. This is the actual, unadjusted (i.e. not weather normalised) summation of actual raw demands for the transmission connection points at the time when this summation is greatest. The Maximum Demand (**MD**) does not include Embedded Generation. $$MD_x = \sum_{1}^{n} MD_{TCPnt}$$ Where MD_x = coincident summed raw system annual maximum demand at Transmission Connection Point level (MW) in year x n = number of JEN Transmission Connection Points t = time of system coincident maximum demand as determined at the transmission connection point level. MD_{TCPnt} = coincident raw unadjusted annual maximum demand at Transmission Connection Point n (MW) in year x at time t	This includes JEN load flowing on JEN subtransmission network only. E.g. TT station load is excluded as TT load is supplied by non-JEN subtransmission lines.

Variable	Source and why actual	Methodology	Assumptions
DOPSD0201	JEN considers this information is actual as it is calculated from historic actual metered MW MD and MVAr drawn from the internal business records. The source of actual information is PI system which stores the historical SCADA metering data.	The MVA MD is calculated from MW MD and MVAr at the time of MW MD. Therefore, MVA MD is the same date and time as MW MD. $$MD_x = \sum_{1}^{n} MD_{ZSSn}$$ Where MD_x = non-coincident summated raw system annual maximum demand at Zone Substation level (MVA) in year x n = number of JEN Zone Substations MD_{ZSSn} = non-coincident raw unadjusted annual maximum demand at Zone Substation n (MVA) in year x The MVA MD is calculated from MW MD and MVAr via the Pythagorean Theorem: $$MVA = \sqrt{(MW^2 + MVAr^2)}$$ The source of MW and MVAr information is PI system and JEN maximum demand forecast excel spread sheet model	The MVAr comes after the application of power factor correction measures at zone substation (e.g. capacitor bank), where applicable. The data includes JEN owned zone substations only i.e it does not include the customer substation and other DNSP owned zone substations.

<table>
<tr><th>Variable</th><th>Source and why actual</th><th>Methodology</th><th>Assumptions</th></tr>
<tr><td>DOPSDO204 (2008-2013)</td><td>JEN considers this information is actual as it is calculated from historic actual metered MW MD and MVAr drawn from the internal business records.

The source of actual information is PI system which stores the historical SCADA metering data.</td><td>The historic for zone substation MW MD and MVAr from PI at the time of system peak are utilised to estimate the data as per the definition of this variable.

The MVA MD is calculated from MW MD and MVAr at the time of MW MD. Therefore, MVA MD is the same date and time as MW MD.

$$MD_x = \sum_{1}^{n} MD_{ZSSnt}$$

Where

MD_x = coincident summed raw system annual maximum demand at ZSS level (MVA) in year x

n = number of JEN zone substations

t = time of system coincident maximum demand at transmission connection point level

MD_{ZSSnt} = coincident raw annual maximum demand at ZSS n (MW) in year x at time t

The MVA MD is calculated from MW MD and MVAr via the Pythagorean Theorem:

$$MVA = \sqrt{(MW^2 + MVAr^2)}$$</td><td>JEN assumed that the summation of actual raw demands for the zone substation is the greatest at the time of coincident peak system demand.

Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible.</td></tr>
</table>

Variable	Source and why actual	Methodology	Assumptions
DOPSD0207	JEN considers this information is actual as it is calculated from historic actual metered MW MD and MVAr drawn from the internal business records. Wholesale market meter data and JEN maximum demand forecast excel spread sheet model are the sources of actual data.	The MVA MD is calculated from metered actual (transmission connection point 15 min- data) MW MD and MVAr at the time of MW MD. Therefore, MVA MD is the same date and time as MW MD. $$MD_x = \sum_{1}^{n} MD_{TCPn}$$ Where MD_x = non-coincident summed raw system annual maximum demand at Transmission Connection Point level (MVA) in year x n = number of JEN Transmission Connection Points MD_{TCPn} = non-coincident raw unadjusted annual maximum demand at Transmission Connection Point n (MVA) in year x The MVA MD is calculated from MW MD and MVAr via the Pythagorean Theorem: $$MVA = \sqrt{(MW^2 + MVAr^2)}$$ Wholesale market meter data and JEN maximum demand forecast excel spread sheet model are the sources of MW and	Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible. MVA MD is assumed to occur at the same date and time as MW MD

Variable	Source and why actual	Methodology	Assumptions
DOPSD0210	JEN considers this information is actual as it is calculated from historic actual metered MW MD and MVAr drawn from the internal business records. Wholesale market meter data and JEN maximum demand forecast excel spread sheet model are the sources of actual data.	MW MD is derived by summation of metered actual raw demands for the transmission connection points (terminal station average 15-min data) at the time when this summation is greatest. The MVA MD is calculated from metered actual of MW MD and MVAr at the time of MW MD therefore MVA MD is the same date and time as MW MD. $$MD_x = \sum_{1}^{n} MD_{TCPnt}$$ Where MD_x = coincident summated raw system annual maximum demand at Transmission Connection Point level (MVA) in year x n = number of JEN transmission connection points t = time of system coincident maximum demand as determined at the transmission connection point level. MD_{TCPnt} = coincident raw unadjusted annual maximum demand at Transmission Connection Point n (MVA) in year x at time t The MVA MD is calculated from MW MD and MVAr via the Pythagorean Theorem: $$MVA = \sqrt{(MW^2 + MVAr^2)}$$ Wholesale market meter data and JEN maximum demand forecast excel spread sheet model are the sources of MW and MVAr data.	Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible. MVA MD is assumed to occur at the same date and time as MW MD.

Variable	Source and why actual	Methodology	Assumptions
DOPSD0301	JEN considers this information is actual as it is calculated from historic actual metered MW MD and MVAr drawn from the internal business records. Wholesale market meter data is the sources of actual data.	As per RIN B definition of power factor $\text{The average overall network power factor} = \frac{\sum_{x=1}^{x=n} MW_x}{\sum_{x=1}^{x=n} MVA_x}$ MW_x =Sum of MW measured in every 15 minute average interval by wholesale market meters in JEN sub transmission connection points MVA_x= Sum of MVA calculated from MW_x and corresponding average MVAr measured in every 15 minute average interval by wholesale market meters in JEN sub transmission connection points	None.
DOPSD0307	JEN considers this information is actual as it is calculated from historic actual metered MW MD and MVAr drawn from the internal business records. Wholesale market meter data is the sources of actual data.	As per RIN B definition of power factor $\text{The average overall network power factor} = \frac{\sum_{x=1}^{x=n} MW_x}{\sum_{x=1}^{x=n} MVA_x}$ MW_x =Sum of MW measured in every 15 minute average interval by wholesale market meters in JEN 66kV sub transmission connection points MVA_x= Sum of MVA calculated from MW_x and corresponding average MVAr measured in every 15 minute average interval by wholesale market meters in JEN 66kVsub transmission connection points	The data for this variable is different from DOPSD0301 as DOPSD0301 includes both 66kV and 22kV sub transmission connection points.
DOPSD0401	JEN's billing is based on measured maximum demand, not on an assumed contracted rate. JEN can therefore not currently provide this information.		

Variable	Source and why actual	Methodology	Assumptions
DOPSD0402	The data is sourced from JEN's two billing systems. The data is then captured in the LCYYYY.xls on a monthly basis and is summed in worksheet Year to date. The information obtained in the reports is actual information as it is consistent with the AER's definition of actual information as per section 2.2.2 of the Better Regulation Explanatory Statement: regulatory information notices to collect information for economic benchmarking November 2013.	The data is obtained from JEN's billing systems where a monthly report is produced from each billing system to record quantities and revenue by tariff component. The data is then captured in the LCYYYY.xls on a monthly basis and is summed in worksheet Year to date.	The tariff codes listed below are incorporated in JEN's approved annual tariffs which are published by the AER.
DOPSD0403-DOPSD0404	JEN does not currently record maximum demand not recorded as MVA.		

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPSD0104	JEN has estimated the data for 2006 and 2007 for this variable because it is calculated and is not an actual, measured value.	The average diversity factor is calculated from the non-coincident summed raw system maximum demand and coincident system maximum demand at zone substation level from the 2008-2013 data. The non-coincident system maximum demands for 2006 & 2007 are then multiplied by the average diversity factor (2008-2013) to get the coincident maximum demand.	JEN assumed that the summation of actual raw demands for the zone substation is the greatest at the time of coincident peak system demand. Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that	This approach is the most reasonable given the availability of data. JEN is not aware of a superior technique, given the data availability constraints.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		$$Coincident\ MD_x = Non - coincident\ MD_x \times \frac{1}{6} \times \times \sum_{n=2008}^{n=2013} DF_n$$ Where: $DF_n = \frac{Coincident\ MD_n}{\mathrm{Non - Coincident\ MD}_n}$ x = 2006 or 2007 $Coincident\ MD_n$ = coincident raw system annual maximum demand at the zone substation level in year n (MW) $\mathrm{Non - Coincident\ MD}_n$= non-coincident raw system annual maximum demand at the zone substation level in year n (MW) $Coincident\ MD_x$ = coincident raw system annual maximum demand at the zone substation level in year x (MW) $\mathrm{Non - Coincident\ MD}_x$= non-coincident raw system annual maximum demand at the zone substation level in year x (MW). The data includes JEN owned zone substations only i.e it does not include the customer substation and other DNSP owned zone substations.	the difference in demand between the 15 minute interval and the precise time of the MD is negligible.	
DOPSD0204 (2006,2007)	JEN has estimated the data for 2006 and 2007 for this variable because it is calculated and is not an	The historic for zone substation MW MD and MVAr from PI at the time of system peak are utilised to estimate the data as per the definition of this variable.	Due to the nonexistence of the PI system before 2008, the same methodology used for 2008-2013 data could not be applied to estimate	This approach is the most reasonable given the availability of data. JEN is not aware of a superior technique, given the data

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	actual, measured value.	The MVA MD is calculated from MW MD and MVAr at the time of MW MD. Therefore, MVA MD is the same date and time as MW MD. $$MD_x = \sum_{1}^{n} MD_{ZSSnt}$$ Where MD_x = coincident summed raw system annual maximum demand at ZSS level (MVA) in year x n = number of JEN zone substations t = time of system coincident maximum demand at transmission connection point level MD_{ZSSnt} = coincident raw annual maximum demand at ZSS n (MW) in year x at time t The MVA MD is calculated from MW MD and MVAr at the time of MW MD via the Pythagorean Theorem: $$MVA = \sqrt{(MW^2 + MVAr^2)}$$ The data for 2006-2007 : The average diversity factor is calculated from the non-coincident summed raw system maximum demand and coincident system maximum demand at zone substation level from the 2008-2013 data. The non-coincident system maximum demands for 2006 & 2007 are then multiplied by the average diversity factor to get the coincident maximum demand.	the data for 2006 & 2007. JEN assumed that the summation of actual raw demands for the zone substation is the greatest at the time of coincident peak system demand determined at the transmission connection points. The MVAr comes after the application of power factor correction measures at zone substation (e.g. Capacitor bank) where applicable. Time of system coincident maximum demand is recorded in average 15 minute intervals using wholesale market meters. It is assumed that the difference in demand between the 15 minute interval and the precise time of the MD is negligible.	availability constraints. The method applied to calculate the MVA MD is well established engineering practice.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOPSD0302,	The variable is estimated due to the assumptions made and that it could not be directly drawn from JEN's internal business records.	Recently measured MW and MVA data for 8 distribution substations (6 commercial, and industrial and 2 domestic loads) are utilised to estimate this variable. The data were captured via power quality meters in every 1 minute interval for around 7 days in each substation. The power quality meters were installed at different dates and time. Due to this reason all the MW and MVA data for different substations are not added together. $$\text{The average power factor for the LV network} = \frac{1}{n}\sum_{x=1}^{n}\frac{MW_x}{MVA_x}$$ MW_x =Sum of MW measured in every 1 minute for a week in substation x. MVA_x= Sum of MVA measured in every intervals as MW measured in substation x	In normal course of business JEN does not record power factor of each individual LV lines. JEN LV load distribution is around 25% Domestic, 75% Commercial and industrial. So the average power factor of this sample of 8 distribution substation (2 domestic, 6 Commercial and industrial loads) gives fair estimate of LV power factor. Due to unavailability of historical data the average power factor of the LV distribution line is assumed to be same from 2006-2013.	This approach is the most reasonable given the availability of data. JEN is not aware of a superior technique, given the data availability constraints.
DOPSD0304, DOPSD0306, DOPSD0308	JEN does not currently have any SWER lines and so cannot populate information for this variable. Historically JEN never had SWER line originating from zone substations and covering the full length of the feeder. In this case, JEN is not able to make an estimate. JEN does not have any 33kV or 132kV lines, therefore no data can be provided for these variables.			
DOPSD0303, DOPSD0305, DOPSD0309	The variable is estimated due to the assumptions made and that it could not be directly drawn from JEN's internal business records.	As per RIN requirement the Total MW and MVA are calculated as below. $$\text{Total MVA} = \sum_{x=t1}^{tn} a_x + \cdots \sum_{x=t1}^{tn} n_x$$	The data provided excludes customer substations and other DNSP owned zone substations for	This approach is the most reasonable given the availability of data. JEN is not aware of a superior technique, given the data availability constraints.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		Where t1 … tn are 15 minute time intervals from 1 January to 31 December. The feeder currents are recorded in every 15 minute interval in OSI PI. $a_x \ldots n_x$= Feeder MVA at time interval x =$\sqrt{3}$ X nominal voltage of the feeder X Feeder current at time interval $\text{Total MW} = \sum_{x=t1}^{tn} A_x + \cdots \sum_{x=t1}^{tn} N_x$ Where, $A_x \ldots N_x$= Feeder MW at time interval x Average power factor = $\frac{\text{Total MW}}{\text{Total MVA}} = \frac{\sum_{x=t1}^{tn} a_x + \cdots \sum_{x=t1}^{tn} n_x}{\sum_{x=t1}^{tn} A_x + \cdots \sum_{x=t1}^{tn} N_x}$ Since only the historical interval data for zone substation MW and Feeder currents are available, the above equation is simplified as below by dividing the numerator and denominator by the number of time intervals Average power factor = $\frac{\text{Total MW}}{\text{Total MVA}} = \frac{\text{Average MW of zone substation 1} + \cdots + \text{Average MW of zone substation N}}{\text{Average MVA of Feeder 1} + \cdots + \text{Average MVA of feeder N}}$ The zone substations and the feeders in above equation are at same voltage level	HV feeders	

6. PHYSICAL ASSETS WORKSHEET

6.1 NETWORK CAPACITIES VARIABLES

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DPA0101-DPA0108	JEN's Geographical Information System (**GIS**) is the single source of actual data for network length. The data is extracted directly from the GIS. The GIS is a live model of the network and represents the network at the current point in time. This means that a snap shot of the GIS network model or data is not made at the end of each year. Therefore it is not possible to report the length of overhead conductors historically. The network length has however been routinely reported from the GIS at the end of each year and we have referred to these reports.	The GIS is the single source of the network connectivity model. The overhead conductors have the voltage and length as attributes and therefore we are able to allocate the conductors into the required categories. The actual data was obtained by running a report directly from GIS at the end of each individual year. 22kV subtransmission has been included in the Overhead 22kV categorisation.	No assumptions have been made in providing this information.

Variable	Source and why actual	Methodology	Assumptions
DPA0201-DPA0208	As above.	The GIS is the single source of the network connectivity model. The underground cables have the voltage and length as attributes and therefore we are able to allocate the conductors into the required categories. The actual data was obtained by running a report directly from GIS. 22kV subtransmission has been included in the Overhead 22kV categorisation.	As above

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DPA0105,DPA0107, DPA0204, DPA0206	JEN does not have any 33kV or 132kV lines, therefore no data can be provided.			
DPA0301	JEN has estimated the data for this variable because it is calculated and is not an actual, measured value.	$Weighted\ average\ Capacity\ of\ LV\ OH\ \ line\ in\ year\ X = \frac{\sum_1^n (s_n l_n)}{\sum_1^n (l_n)}$ Where: n = number of sections of LV conductor existing on JEN network in year X s_n= MVA rating of section n of LVOH conductor l_n= length of section n of LVOH conductor JEN has referred JEN's Geographical Information System (**GIS**), Jemena Planning manual, Jemena Construction Manuals and VESI Manuals (Historical construction and design manuals used by SECV) to populate this variable.	For the ratings of LV lines, current and historical construction and design manuals used by JEN/its predecessors and current standards have been used. Majority of "date constructed" for LV OH conductor is found date = NULL in GIS. This is legacy data and was captured prior to the date field being made mandatory within the GIS Data Model circa 2010. For the purposes of the weighted average MVA calculation, if the construction date is NULL in GIS, it is assumed that these were constructed	This approach is the most reasonable given the availability of data. JEN is not aware of a superior technique, given the data availability constraints.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
			prior 2006. The unknown type and cross section of conductors are not included in the calculations. The data provided covers more than 61% of total length (as of 31/12/2013) of OH LV recorded in GIS. It is assumed that this sample is a fair representation of the population of LV conductors on the JEN. When a conductor is replaced the date constructed, cross sectional area, conductor material fields etc. are overwritten in the GIS. Therefore, where conductors have been replaced, the previous data cannot be included in the calculation for years prior to the reconductoring. Single phase and 2 phase lines are not included in the calculation. Conductor ratings in manuals/standards are given in Amps, therefore nominal voltage of the line is used to convert to MVA. As JEN is summer peaking network, the summer ratings of OH conductors have been utilised to calculate the MVA capacity.	
DPA0303,	JEN does not currently have any SWER lines. JEN does not have sufficient record of historic SWER lines,	$SWER\ MVA\ Capacity = 12.7kV \times 28\ A \times .001$ Where 12.7kV is the SWER line voltage and 28A is the rating of 3/2.75 SC/GZ for design temperature of 50/25^{0}C.	All the SWER lines assumed to be constructed with the standard size of galvanized steel conductor 3/2.75 SC/GZ	This approach is the most reasonable given the availability of data.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	therefore the information is estimated.		The rating of 3/2.75 SC/GZ is taken as 28A for design temperature of 50/25 ^{0}C.	
DPA0305, DPA0307	JEN does not have any 33kV or 132kV lines, therefore no data is provided.			

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DPA0306	JEN has estimated this variable as it does not currently capture weighted average MVA capacity for sub transmission lines in the normal course of business. As the data is not directly available from JEN's internal business records, a suitable estimate is provided.	$$Weighted\ average\ Capacity\ of\ subtransmission\ OH\ \ line\ in\ year\ X\ = \frac{\sum_1^n (s_n l_n)}{\sum_1^n (l_n)}$$ Where: n = number of sections of 66kV conductor existing on JEN network in year X s_n= Summer MVA rating of limiting section of subtransmission line which section n belongs to, regardless of whether limiting section is overhead or underground l_n= length of section n of 66kV OH conductor JEN has referred JEN's Geographical Information System (**GIS**), Circuit data sheets Jemena Planning manual and historical Distribution System Planning Reports to populate this variable.	As it is extremely time consuming to locate the rating and length of every section of line from circuit data sheets for all subtransmission line CDS , the summer rating of limiting section of individual subtransmission line is included in the calculation. Only JEN owned subtransmission are included in the calculation. There can be small differences in line length records between CDS and GIS. The length from GIS has been applied in the calculation. For legacy data migrated from the SECV DMS2 GIS System the date = 01/01/1970 is used in records that had NO DATE (Unknown) prior to the implementation of the Solaris GIS in 1995, this is a default date programmatically populated. For the purposes of the weighted average MVA calculation, if the construction date is NULL it is assumed that these were constructed prior to 2006. When a conductor is replaced with higher rating or thermally uprated the date constructed, cross sectional area, conductor material fields etc. are	This approach is the most reasonable given the availability of data.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
			overwritten in the GIS. Conductor ratings in CDS are given in Amps, therefore nominal voltage of the line is used to convert to MVA. As JEN is summer peaking network, the summer ratings of OH conductors have been utilised to calculate the MVA capacity.	
DPA0302, DPA0304, DPA0308	JEN has estimated this variable as it does not currently capture the weighted average MVA capacity for HV OH lines in the normal course of business. As the data is not directly available from JEN's internal business records, a suitable estimate is provided.	$Weighted\ average\ Capacity\ of\ HV\ OH\ \ line\ in\ year\ X = \frac{\sum_1^n (s_n l_n)}{\sum_1^n (l_n)}$ Where: n = number of sections of HV conductor existing on JEN network in year X s_n= MVA rating of section n of HV OH conductor l_n= length of section n of HV OH conductor JEN has referred JEN's Geographical Information System (**GIS**), Jemena Planning manual / construction manuals JEN SCADA, SECV conductor rating practices to populate this variable.	In business as usual activities JEN has records of overall nominal ratings of the feeders which are calculated as below. Generally, the capacity of a feeder is limited by the current carrying capacity of the overhead or underground sections on the main backbone. The limiting section of a backbone is likely to be close to the zone substation. The overall nominal rating of a feeder is defined as the limiting backbone section of conductor (overhead or underground) where the capacity utilisation is the greatest. The weighted average capacity calculation methodology used does not account for capacity which cannot be utilised due to upstream limitations. Majority of 'date constructed' for HV OH conductor is found date = NULL in GIS. This is legacy data and was captured prior to the date field being made mandatory within the GIS data	This approach is the most reasonable given the availability of data. JEN is not aware of a superior estimation technique, given the data availability constraints.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
			model, circa 2010. For the purposes of the weighted average MVA calculation, if the construction date is NULL it is assumed that these were constructed prior to 2006. The unknown type and cross section of conductors are not included in the calculations. So the data provided covers more than 90% of total length (as of 31/12/2013) of OH HV recorded in GIS. It is assumed that this sample is a fair representation of the population of HV OH conductors on the JEN. When a conductor is replaced with higher rating or thermally uprated, the date constructed, cross sectional area, conductor material fields etc. are overwritten in the GIS. Therefore, where conductors have been replaced or thermally uprated, the previous data cannot be included in the calculation for years prior to the cable replacement. Single phase lines are assumed to be 3 phase for the purpose of the calculation. Conductor ratings in manuals/standards are given in Amps, therefore nominal voltage of the line is used to convert to MVA.	

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
			Variable DPA0304 also includes the data for 22kV OH sub transmission. As JEN is summer peaking network, the summer ratings of OH conductors have been utilised to calculate the MVA capacity.	
DPA0401	JEN has estimated the data for this variable because it is calculated and is not an actual, measured value.	The basis of JEN's estimate is set out in the formula below: $Weighted\ average\ Capacity\ of\ LV\ UG\ \ line\ in\ year\ X = \frac{\sum_1^n (s_n l_n)}{\sum_1^n (l_n)}$ Where: n = number of sections of LV cable existing on JEN network in year X s_n= MVA rating of section n of LVUG cable l_n= length of section n of LV UG cable JEN has referred JEN's Geographical Information System (**GIS**), Jemena Planning manual, Jemena Construction Manuals and VESI Manuals (Historical construction and design manuals used by SECV) to populate this variable.	For the ratings of LV Underground (**UG**) cables, current and historical construction and design manuals used by JEN/its predecessors and current standards have been used. Ratings are based on standard design depth, temperature, proximity to other cables etc and do not allow for any variations from this which may exist in the field. This is due to the absence of this data in GIS. Majority of 'date constructed' for LV UG cable is found date = NULL in GIS. This is legacy data and was captured prior to the date field being made mandatory within the GIS Data Model Circa 2010. For the purposes of the weighted average MVA calculation, if the construction date is NULL it is assumed that these were constructed prior to 2006. The unknown type and cross section of conductors are not included in the calculations. The data provided	This approach is the most reasonable given the availability of data. JEN is not aware of a superior estimation technique, given the data availability constraints.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
			covers almost 60% of total length (as at 31/12/2013) of LV UG recorded in GIS. It is assumed that this sample is a fair representation of the population of LV UG cables on the JEN. When a conductor is replaced the date constructed, cross sectional area, conductor material etc. fields are overwritten in the GIS. Therefore, where cables have been replaced, the previous data cannot be included in the calculation for years prior to the cable replacement. Only 3 core and 4 core cables are included in the calculation. Underground service cables are not included in the calculation.	
DPA0402, DPA0403, DPA0408	JEN has estimated this variable as it does not currently capture the weighted average MVA capacity for HV underground network in the normal course of business. As the data is not directly available from JEN's internal business records, a suitable estimate is provided.	The basis for JEN's estimate is set out in the formula below: $Weighted\ average\ Capacity\ of\ HV\ UG\ \ line\ in\ year\ X = \frac{\sum_1^n (s_n l_n)}{\sum_1^n (l_n)}$ Where: n = number of sections of HV cable existing on JEN network in year X s_n= MVA rating of section n of HV UG cable l_n= length of section n of HV UG cable JEN has referred JEN's Geographical Information System (**GIS**), current and historical construction and	In business as usual activities JEN has records of overall nominal ratings of the feeders which are calculated as below. Generally, the capacity of a feeder is limited by the current carrying capacity of the overhead or underground sections on the main backbone. The limiting section of a backbone is likely to be close to the zone substation. The overall nominal rating of a feeder is defined as the limiting backbone section of conductor (overhead or underground) where the capacity utilisation is the greatest. The	This approach is the most reasonable given the availability of data. JEN is not aware of a superior estimation technique, given the data availability constraints.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		design manuals used by JEN/its predecessors and current standards have been used.	weighted average capacity calculation methodology used does not account for capacity which cannot be utilised due to upstream limitations. Ratings are based on standard design depth, temperature, proximity to other cables etc and do not allow for any variations from this which may exist in the field. This is due to the absence of this data in GIS. Majority of 'date constructed' for HV UG cable is found date = NULL in GIS. This is legacy data and was captured prior to the date field being made mandatory within the GIS data model, circa 2010. For the purposes of the weighted average MVA calculation, if the construction date is NULL it is assumed that these were constructed prior to 2006. The unknown type and cross section of conductors are not included in the calculations. So the data provided is covers more than 98% of total length (as of 31/12/2013) of HV UG recorded in GIS. It is assumed that this sample is a fair representation of the population of HV UG cables on the JEN network. When a cable is replaced with higher rating the date constructed, cross	

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
			sectional area, conductor material etc. fields are overwritten in the GIS. Therefore, where cables have been replaced, the previous data cannot be included in the calculation for years prior to the cable replacement. Variable DPA0403 also includes the data for 22kV UG subtransmission.	
DPA0405	JEN has estimated this variable as it does not currently calculate weighted average MVA capacity for sub transmission lines in the normal course of business. In business as usual activities JEN has record of subtransmission lines ratings stored in Drawbridge as pdf circuit data sheets. Overall nominal rating of sub transmission lines, which is the lowest current carrying capacity of overhead or underground sections along the line, are readily available in Excel format. To calculate weighted average from individual sections of each line would be an unnecessarily burdensome manual process particularly given the availability of a	The basis of JEN's estimate is set out in the formula below: $$Weighted\ average\ Capacity\ of\ subtransmission\ UG\ line\ in\ year\ X = \frac{\sum_1^n (s_n l_n)}{\sum_1^n (l_n)}$$ Where: n = number of sections of 66kV cable existing on JEN network in year X s_n= Summer MVA rating of limiting section of subtransmission line which section n belongs to, regardless of whether limiting section is overhead or underground l_n= length of section n of 66kV UG cable JEN has referred JEN's Geographical Information System (**GIS**), Circuit data sheets Jemena Planning manual and historical Distribution System Planning Reports to populate this variable.	As it is time consuming to get the rating and length of every section from circuit data sheet for all subtransmission line CDS , the summer rating of limiting section of individual subtransmission line is included in the calculation. Only JEN owned subtransmission are included in the calculation. There might be small difference in the length of the lines in CDS and GIS. The length from GIS is taken into account for calculation. For legacy data migrated from the SECV DMS2 GIS System the date = 01/01/1970 is used in records that had NO DATE (Unknown) prior to the implementation of the Solaris GIS in 1995, this is a default date programmatically populated. For the purposes of the weighted average MVA calculation, if the	This approach is the most reasonable given the availability of data. JEN is not aware of a superior estimation technique, given the data availability constraints.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	suitable estimate.		construction date is NULL it is assumed that these were constructed prior to 2006. When a UG cable is replaced with higher rating, the date constructed, cross sectional area, conductor material fields etc. are overwritten in the GIS. Cable ratings in CDS are given in Amps, therefore nominal voltage of the line is used to convert to MVA.	
DPA0404, DPA0406	JEN does not have any 33kV or 132kV lines and has therefore not provided any information relating to these variables.			
DPA0407	JEN does not currently have any SWER lines. JEN does not have sufficient record of historic SWER lines, therefore the information is estimated.	$Underground\ SWER\ MVA\ Capacity = 12.7kV \times 145\ A \times .001$ Where 12.7kV is the SWER line voltage and 145A is the rating of 35mm for design temperature of 50/25^{0}C.	All the underground SWER is assumed to be constructed with the standard size of 35mm 22kV 1 core XLPE cable. The design rating of 35mm 22kV 1 core XLPE cable in conduit is taken as 145A.	This approach is the most reasonable given the availability of data.

6.2 TRANSFORMER CAPACITIES VARIABLES

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DPA0501	The information was sourced from GIS and is considered actual information as GIS is a direct source of actual information.	The distribution transformer capacity is a characteristic of each of the distribution transformers. We have been required to report this figure each year and so it is an actual.	There are no assumptions.
DPA0601, DPA0602	JEN does not have any two-step transformations and has therefore provided no information relating to these variables.		
DPA0603, DPA0604	JEN considers this information to be actual information as it can be directly drawn from JEN's internal business records and regulatory submissions. JEN has referred to previous regulatory submissions and historical Distribution System Planning Reports to populate this variable.	This is the summation of normal assigned continuous capacity / rating (with forced cooling or other capacity improving factors included if relevant). Assigned rating may be nameplate rating, or rating determined from results of temperature rise calculations from testing. This rating is the lower of the thermal capacity of transformers or the zone substation exit feeder capacity.	This does not include the customer substation and other DNSP owned zone substations supplying JEN customers.
DPA0605	JEN does not have any cold spare zone substation transformers, as per JEN policy. Therefore no information is provided in relation to this variable.		

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DPA0502	As per the AER RIN explanatory statement where this information is not available to	The maximum demand for HV customers was extracted from JEN's billing systems for the period 2008 to 2013. This MD information is maintained	The average JEN HV customer maximum demand is greater than 2MVA, therefore a power factor of 0.9	This approach is the most reasonable given the availability of data. JEN is

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	the NSP, it is to report a summation of non-coincident individual maximum demands of each such directly connected customer whenever they occur (ie the summation of a single annual MD for each customer) as a proxy for capacity within the customer's installation. The variable should be the sum of the direct information where this is available and of the proxy MVA measure where the direct measure is not available. JEN does not currently record the distribution transformer capacity owned by high voltage customers and has therefore provided a suitable estimate.	in kW in JEN's billing system—not MVA. The (2008-2013) information is thereby converted to MVA using the methodology detailed below. An assumed power factor of 0.9 lagging, as per Electricity Distribution Code Clause 4.3 Table 2, is used to convert the kW MD to KVA MD of individual HV customer. Data 2006-2007:This data is estimated by the following method: Non-coincident high voltage customer demand (MW) at 2006 = average ratio (2008-2013) of non-coincident HV customer demand to the system non-coincident maximum demand at the zone substation level, multiplied by the 2006 non-coincident system MW maximum demand at the zone substation level. $Customer\ MD_x = System\ MD_x \times \frac{1}{6} \times \times \sum_{n=2008}^{n=2013} \frac{Customer\ MD_n}{\text{System MD}_n}$ Where: x = 2006 or 2007 $Customer\ MD_n$ = sum of non-coincident HV customer MDs in year n in MW System MD_n=non-coincident system MD at the zone substation level in year n in MW System MD_x=non-coincident system MD at the zone substation level in year x in MW	lagging is assumed to be reasonable as this is the minimum power factor that customers with maximum demand greater than 2MVA must (as per Electricity Distribution Code clause 4.3 table 2). JEN has applied the definition of 'high voltage' applied in its EDPR RIN 2010. Ie—Assets that distribute electricity at voltage levels between the sub transmission and LV sections of the network. The connection boundaries are the outgoing terminals of the HV circuit breakers at the zone substations to the LV terminals of the HV to LV distribution transformers The data provided does not include the sub transmission customers as per the above HV definition.	not aware of a superior estimation technique, given the data availability constraints.
DPA0503	JEN did not record the actual	The cold spare capacity for 2007 has been	JEN has applied the assumption that	This is considered the best

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	cold spare capacity for 2007 and is unable to calculate this figure retrospectively.	estimated. It is the average of the 2006 and 2008 actual numbers.	only the capacity that is held in emergency stock should be classified as cold spare capacity. Capacity that is held as stock which is reserved for construction projects has not been classified as cold spare capacity.	estimate on the basis that an average fits the trend over the 2006 to 2011 period.

6.3 PUBLIC LIGHTING

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DPA0701	JEN's GIS is the single source of actual data for the public lighting inventory. The data is extracted directly from the GIS and is therefore considered to be actual information. The GIS is a live model of the network and represents that network at the current point in time. This means that a snap shot of the GIS network model or data is not made at the end of each year. Therefore it is not possible to report the number of luminaires historically. The number of luminaires has however been routinely reported from the GIS at the end of each year and we have referred to these reports.	The GIS is the single source of the public lighting physical inventory, therefore JEN are able to count the number of luminaires. The actual data was obtained by running a report directly from GIS at the end of each individual year.	No assumptions have been made in providing this information.

Variable	Source and why actual	Methodology	Assumptions
DPA0702	JEN's GIS is the single source of actual data for the public lighting inventory. The data is extracted directly from the GIS and is therefore considered to be actual information.	The number of public lighting poles has been reported in the 2011 and 2012 annual RIN and we have referred to these sources. The number of public lighting poles for 2013 has been reported directly from GIS. Therefore the numbers for 2011, 2012 and 2013 are actuals. The GIS records the pole classification, installation date for new poles and the removal date for removed poles. For the purpose of this RIN, JEN has calculated the number of poles for the end of each year for 2006-2010. For example, to calculate the number of poles at the end of 2010, we have taken the number of poles reported in 2011 (actual), subtracted the number of poles installed in 2011 (actual) and added the number of poles removed in 2011 (actual)	In applying this methodology, it has been assumed that the pole installation and pole removal dates have been accurately recorded in GIS for 2006 to 2010.

ESTIMATED INFORMATION

No estimated information is provided.

7. QUALITY OF SERVICE

7.1 RELIABILITY

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DQS0101-DQS0108	JEN considers this information to be actual information as it is maintained directly within its Outage Management System (**OMS**). JEN's OMS is the repository for all outage information, including outage dates and times, the number of customer affected, restoration dates and times and restoration stages.	The data used to calculate the reliability variables (Key Performance Indicators (**KPI**)) is extracted from the OMS at the end of each month and is validated and cleansed to correct data errors. The cleansed data is loaded into the Customer Minutes Off Supply (**CMOS**) database. The reliability KPI's are then calculated. The reliability variables (KPI's) have been routinely reported from the CMOS database at the end of each month and we have referred to these reports. The reliability variables (KPI's) are consistent with those that have been previously reported to regulatory authorities.	No assumptions have been made in providing this information.

ESTIMATED INFORMATION

No estimated information is provided.

7.2 ENERGY NOT SUPPLIED

ACTUAL INFORMATION

No actual information is provided.

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DQS0201-DQS0202	JEN has estimated these variables because it is calculated and is not an actual, measured value. The energy not supplied has been routinely reported by JEN at the end of each year. JEN has referred to these reports to populate these variables. The feeder maximum demand , load factor and number of customers are calculated using data from JEN's core asset management systems.	The methodology that has been used is the fourth option, outlined on page 37 of "Economic benchmarking RIN for distribution network service providers – Instructions and Definitions (November 2013)" That is, JEN has used the average feeder demand derived from feeder maximum demand and estimated load factor, divided by the number of customers on the feeder. Planned energy not supplied is increasing over the period due to increasing capital expenditure on the network. The proportion of capex spent on the distribution network (contribution to planned energy not supplied) has increased compared to zone substation capex (no contribution to planned energy not supplied) in the later years of the period. Generally, zone substation projects have little requirement for planned interruptions to customers and therefore little to no contribution to planned energy not supplied. Distribution projects are the dominant	The planned energy not supplied has been consistently calculated with a factor of 0.3 since 1997. The assumption has considered that customers have given notice 4 days before the outage, energy usage would just be diverted to times when supply is available and the actual energy not supplied would only be the base continuous consumption such as operating a fridge. The assumption and the adjustment factor was communicated to the Regulator (Office of the Regulator General (**ORG**)) before the 1997 annual report was submitted. There has been no instruction from the Regulator since indicating that the assumption should not be applied. JEN has used the average feeder demand derived from feeder maximum demand and estimated load factor, divided by the number of customers on the feeder.	JEN has adopted the fourth estimation option for average customer demand because all inputs to calculate average customer demand on a feeder are readily available. To report using options 1-3 would require multiple IT system enhancements to merge the information from various sources.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		contributors to planned energy not supplied. The variation is also dependent on the scope of the projects. Unplanned energy not supplied is dependent on the number of unplanned outages and the nature/damage/date/time/network topology/available capacity etc. of the outages defined the duration of the outages. Unplanned energy not supplied is function of unplanned customer-minutes-off-supply. As the RIN unplanned energy not supplied definition required the exclusion of excluded outages, the profile is closely aligned with DQS0102 - Whole of network unplanned SAIDI excluding excluded outages. The spike was due to the biggest Major Event Day (**MED**) since industry privatisation. It was a severe storm day on 2 April 2008 (daily unplanned SAIDI of 48.19 minutes).		

7.3 SYSTEM LOSSES

ACTUAL INFORMATION

No actual information is provided.

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DQS03	JEN has estimated this variable as system loss data is captured internally in financial years (i.e. 1 July to 30 March), not in calendar years. JEN had to therefore convert the data to calendar years (using some assumptions). JEN cannot therefore claim the variable to be actual information.	JEN has adopted the methodology published by the Essential Services Commission (**ESC**) in February 2007 for the determination of distribution loss factors. This methodology is based on the methodology jointly developed by the Victorian distribution businesses, having regard to the principles of clause 3.6.3 (h) of the NER. The calendar year data is derived by taking the average of 2 consecutive financial year system losses. For example system loss for CY 2006 is the average of system losses in FY 2005/06 and 2006/07. $DLF_{CY} = \frac{DLF_{(CY-1)/CY} + DLF_{CY/(CY+1)}}{2}$ where: DLF = Distribution loss factor (%) CY = Calendar year $DLF_{(CY-1)/CY}\ or\ DLF_{CY/(CY+1)}$ = Financial year distribution loss factor (%) Wholesale market meter data, embedded generation data, billing system and cross boundary flow energy meter data are the sources for historical energy import and export data.	The FY 2013/14 data (used to derive CY 2013 year data) is forecast based on forecast energy sales (i.e. electricity delivered) because forecast energy purchase (i.e. electricity imported) data for FY 2013/14 is not yet available. Energy received from solar PV is included in the calculation from FY 2011/12 onwards.	This approach is the most reasonable given the current methodology used to calculate Distribution Loss Factor (**DLF**) and definition of the variable.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate

7.4 CAPACITY UTILISATION

ACTUAL INFORMATION

No actual information is provided.

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DQS04	JEN has estimated this variable as it requires a calculation of both actual and estimated source data, and could not be directly drawn from internal business records. The zone substation transformer MVA capacity is actual data as per source of DPA0604 Zone substation raw actual maximum demand (MVA) is estimated from MW and MVAr data at the time of MW MD as per DOPSD0201 Zone substation utilisation is calculated based on the actual and estimated data above.	The overall utilisation for JEN owned zone substations is calculated each year by dividing the sum of non-coincident maximum demand at the zone substation level by summation of zone substation thermal capacity. $U_{ave} = \frac{MD_{ZSS}}{C_{ZSS}}$ Where: U_{ave} = Overall utilisation of JEN zone substations in year X MD = sum of non-coincident Maximum Demand (MVA) at the zone substation level (only JEN owned zone substations). This is equal to variable DOPSD0201. C_{ZSS} = summation of JEN owned zone substation thermal capacity. This is calculated as DPA0604 minus DPA0605.	Capacity utilisation is a measure of the capacity of zone substation transformers that is utilized each year. The zone substation MVA MD is taken after the application of power factor correction e.g capacitor banks This does not include the customer substation and other DNSP owned zone substations. Not all capacities of zone substations are the nameplate ratings of the transformers. Some are de-rated due to limiting capacity of zone substation exit feeder capacity, some due to voltage drop limitation etc.	JEN considers this to be its best estimate as the method applied to calculate the overall capacity is as per the RIN definition of the variable.

8. OPERATING ENVIRONMENT FACTORS WORKSHEET

8.1 DENSITY FACTORS

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DOEF0102	JEN considers this variable to be actual information as the data is calculated from the variable code DOPED01, which is total energy delivered, and variable code DOPCN01, which is total customer numbers—both directly reconcilable with JEN's internal business records.	DOEF0102 is derived as follows: variable DOPED01 is converted to MWh and divided by variable DOPCN01. Formula: (DOPED01*1000)/DOPCNO1	As per variable codes DOPED01 and DOPCN01.

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOEF0101	JEN has estimated this variable as the data is calculated from the variable code DOEF0301, which is estimated route line length, and variable code DOPCN01, which is total customer numbers. As one of the key inputs is estimated information, JEN considers this variable to also be an estimate.	The data is calculated by dividing the variable code DOEF0301, which is estimated route line length, by the variable code DOPCN01, which is total customer numbers.	As per variable codes DOEP0103 and DOPCN01	This approach is the most reasonable given the availability of data. JEN is not aware of a superior estimation technique, given the data availability constraints.
DOEF0103	JEN has estimated this variable as the data is calculated from the variable_code DOPSD0201,	The basis for this estimate is calculated as per the definition of variable i.e. kVA non-coincident Maximum demand (at zone	As per variable codes DOPSD0201 and DOPCN01	This approach is the most reasonable given the availability of data. JEN is not

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
	which is estimated information of MVA non-coincident maximum demand at zone substation level, and variable code DOPCN01, which is total customer numbers. As one of the key inputs is estimated information, JEN considers this variable to also be an estimate.	substation level)/ no of customers $$DF_x = \frac{MD_x}{C_x}$$ Where: DF_x = Density Factor for year x MD = non-coincident maximum demand at zone substation level (kVA) in year x as per variable_code DOPSD0201 / 1000 C = total number of customers on JEN network in year x as per variable code DOPCN01		aware of a superior estimation technique, given the data availability constraints.

8.2 TERRAIN FACTORS

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DOEF0202 - DOEF0204 and DOEF0214	The source of the information is the Vegetation Management System (**VMS**). The data is collected in the field and entered into data collection devices and is then loaded into the VMS. Reports are run directly from the VMS. JEN thereby considers these variables to be actual	The data collected in the field and loaded into the VMS includes the feeder that the span is connected to (thus it is possible to determine whether the feeder is in the rural or urban area and whether it is in a bushfire risk area as defined by the Country Fire Authority (**CFA**)).	No assumptions have been made in providing this information.

Variable	Source and why actual	Methodology	Assumptions
	information as they can be directly drawn from JEN's internal business records.		
DOEF0205	JEN's GIS is the single source of actual data for the pole inventory. The data is extracted directly from the GIS and is therefore considered actual information. The GIS is a live model of the network and represents that network at the current point in time. This means that a snap shot of the GIS network model or data is not made at the end of each year. Therefore it is not possible to report the number of poles historically. The number of poles has however been reported in the 2009 and 2010 JEN Asset Management Plans whilst for 2011 and 2012 the number of poles have been reported in the annual RIN and we have referred to these sources. The number of poles for 2013 has been reported directly from GIS.	Jemena records the number of poles and does not record the number of spans. The total number of spans is the total number of poles less one.	The assumption has been made that public lighting poles are to be included in the total pole number because there are public lighting poles that are serviced overhead as well as underground. The public lighting poles that are serviced underground also receive management to clear vegetation from around poles.
DOEF0210	JEN considers this variable to be actual information as the average number of defects per vegetation maintenance span is extracted from process data captured in the VMS. All information can be directly verified via VMS.	The average number of Defects per vegetation Maintenance Span is calculated by dividing the number of Defects (action spans) with maintenance spans at the end of each calendar year. JEN refers to this average as the "find rate" for a given year.	A "defect" is defined as any span which requires cutting (pruning or removal) in the year in question and is known as an "action span" in the VMS.
DOEF0211	As above.	As above.	As above.

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOEF0201	This is an actual number for 2013. Because a snapshot of the line length was not recorded for the rural feeders (in fact any feeders) in previous years they were estimated based on the Rural to Total feeder length proportion calculated for the 2013 year. This proportion was then applied to known total feeder lengths of years 2009 to 2012 inclusive.	An actual number is provided for 2013. Prior years are estimated based on the rural to total feeder length ratio calculated for the 2013 year. This ration was then applied to known total feeder lengths of years 2009 to 2012 inclusive.	The proportions of line lengths between rural and urban have remained relatively constant.	JEN considers this to be its best estimate given that the total line length for each year is an actual figure. Thereby the total feeder length proportion is a function of actual information.
DOEF0206 - DOEF0207	The source of the information is the annual Jemena Electric Line Clearance Management Plans for these years, which document the actual vegetation maintenance span cycles applied to each of the respective years.	The methodology that has been used is to determine the optimum cycle which is compliant with Electric Line Clearance Regulations 2006 and more recently 2010. Note: the maintenance span cycle is 1, 2 or 3 years, no rounding has been used.	No assumptions have been made in providing this information.	JEN considers this to be its best estimate because the methodology that has been used (to determine the optimum cycle) is compliant with Electric Line Clearance Regulations 2006 and more recently 2010.
DOEF0208	The Vegetation Management System (**VMS**) does not record the number of trees actually requiring maintenance. The VMS records the number of maintenance spans but not the number of trees per maintenance span. Therefore JEN provided an estimate for this information.	Average number of trees obtained from a physical survey of 150 urban spans conducted in Jan 2014.	Based on local knowledge the spans selected for survey were assumed to be representative of all urban maintenance spans. It is assumed that Jan 2014 survey results are held constant over the period 2009 to 2013. If a tree was likely to require pruning within the next 5 years it was counted as	The estimate is JEN's best estimate because the methodology is representative and provides reasonable accuracy. Other photographic data sources such as NDVI and NVIS do not lend themselves to accurate estimations numbers of trees per maintenance span.

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
			a tree in that span. Locations for the survey were chosen on experience so as not to overstate or understate the average number of trees per span. Spans without trees were also counted giving a result representative of the total number of trees managed in the urban area.	Also these systems require significant resource and time allocation to apply.
DOEF0209	As above.	Average number of trees obtained from a physical survey of 100 rural spans conducted in Jan 2014.	Based on local knowledge the spans selected for survey were assumed to be representative of all rural maintenance spans. It is assumed that Jan 2014 survey results are held constant over the period 2009 to 2013. If a tree was likely to require pruning within the next 5 years it was counted as a tree in that span. Locations for the survey were chosen on experience so as not to overstate or understate the average number of trees per span.	As above.
DOEF0213	JEN has estimated this information because this variable is not recorded in the GIS as a characteristic against each pole.	The estimate is made based on local knowledge and relevant safety legislation e.g. CFA Act which states that petrol powered vehicles are not to be driven where their exhaust systems may contact	To arrive at a number which is the most realistic, the following assumptions were made: 1. All poles in the urban areas can be accessed by standard vehicles, therefore	JEN considers this to be its best estimate as the basis of the estimate is robust, and furthermore, the JEN area is relatively flat and most poles

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
		vegetation such as grass, during the declared fire danger period (approximately 6 months in any 12 month period). Methodology used is as follows: 1. An average HV and ST span in the rural area is calculated based on the total length of HV and ST conductor length and the number of all poles supporting these conductors in this area. Some poles may be counted twice in order to estimate a realistic span length. 2. The GIS is used to find all poles located on private property in rural areas. These poles are filtered such that only poles supporting HV or ST are counted and each pole is only counted once. 3. The inaccessible line length is calculated by multiplying item 1 and 2 above. 4. The accessible line length is calculated by subtracting item 3 above from the total JEN circuit length for all voltages.	poles/lines in rural areas only are considered for this variable. 2. All poles supporting LV in the rural areas are accessible by standard vehicles. 3. All private poles in the rural areas are accessible by standard vehicles. 4. Only JEN owned poles need to be accessed. 5. All poles not accessible by standard vehicle are accessible in a straight line along the span. 6. Due to the weight of equipment being carried this estimate does not apply to asset inspection and work crew vehicles. 7. A standard vehicle is reference to a two wheel drive sedan/hatch type vehicle predominantly for the use by office based staff for auditing, scoping, event investigation or similar purposes. 8. Only poles supporting HV or ST lines which are not on a road reserve are inaccessible by standard vehicle due to the designed route of these lines.	are accessible within 10km on foot from the nearest road or path accessible by standard vehicle. The use of non-standard vehicles allows for better and more timely information capture for auditing or job scoping purposes. Whilst some LV only poles are inaccessible by standard vehicles the majority are in relative close proximity to dwellings (assumed to be accessible by standard vehicle). Conversely poles supporting HV lines were generally designed to take the shortest route and most do not have defined paths leading to or near them. It is JEN's experience that none of these poles are accessible in a straight line from pole to pole but because the location and length of paths (route to the pole) is not recorded and not wishing to overstate the distance to a pole (only the portion inaccessible to a standard vehicle) JEN chose to represent 100% of the distance

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
				between poles off road.

8.3 SERVICE AREA FACTORS

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DOEF0301 (2013 only)	JEN considers this variable to be actual information as the information was sourced from GIS.	A program was written to determine the route line length at the end of 2013.	No assumptions made.

ESTIMATED INFORMATION

Variable	Why estimate, not actual	Basis for estimate	Assumptions	Why best estimate
DOEF0301 (2006 – 2012)	JEN's GIS does not maintain a snap shot of the network model at the end of each year, and due to the fact that JEN have not been required to report route length in the past, JEN cannot provide the route length for 2006-2012 with actual information—it must be estimated. JEN's GIS is a live model of the network and represents that network at the current point in time. This means that a snap shot of the GIS network model or data is not made at the end of each year. Therefore it is not possible to report the route line length historically. The route line length has however been determined from the GIS at the end of 2013.	The basis of JEN's estimate is that JEN assumed that the route length varied each year in proportion to the change in the overhead network line length. So, the route length was estimated based on the change in the overhead line length each year. A program has been developed within the GIS to determine the route length of the network. The methodology used was to determine where there were single circuits between poles and where there were multiple circuits between poles. Where there are multiple circuits the span length between poles has only been included once. The spans length of the single circuits has then been added to determine the total route length.	Assumption made was that only overhead conductor route length was to be considered, that is underground cable route length was excluded. Length of overhead services from poles to premises was excluded from the route length calculation.	This is the best estimate because it has been calculated using a programmed methodology that is able to be repeated and is considered to provide an accurate result.

8.4 WEATHER STATIONS

ACTUAL INFORMATION

Variable	Source and why actual	Methodology	Assumptions
DOEF04001 - DOEF04032	The source of the information for the Weather Stations was the Bureau of Meteorology (**BOM**). The data was sourced in early 2014 and is considered to be accurate. JEN considers this weather information to be actual information. Note: although the weather station details are actual data, the data that these provide (e.g. rainfall) are estimates. For instance, a rain gauge at a weather station measures how much rain is collected for that gauge. Although an actual measure for that gauge, it is an estimate of how much rain fell in a particular area or post code.	Weather stations that are located within the JEN territory have been included in this section.	The assumption that has been made is that the details of the weather stations that have been sourced from the BOM are accurate and up to date. Weather stations that were provided by the BOM and are outside the JEN territory have been excluded as they are not considered to be relevant to the management of the JEN network. Weather stations that have not recorded any weather data since January 2013 are not considered operational and therefore are unable to provide data that is relevant to the management of the JEN network.

ESTIMATED INFORMATION

No estimated information is provided.

1. ATTACHMENT 1

1.1 PROCEDURE 4.4.1 ASSET LIVES – ESTIMATED SERVICE LIFE OF NEW ASSETS FEB 2014

Procedure: 4.4.1. Asset Lives - Estimated Service Life of New Assets
For Category 1 – Overhead network assets less than 33kV (wires and poles)

The assets are (as per RAB):

1. HV Poles and Pole Tops
   - Staked wooden poles HV
   - Wooden poles HV
   - Concrete poles HV
   - Steel poles HV
   - Wooden cross arm HV
   - Steel cross arm HV
2. HV OH Conductor
   - Conductor HV (ABC)
   - Conductor HV (Bare)
3. LV Poles and Pole Tops
   - Staked wooden poles LV
   - Wooden poles LV
   - Concrete poles LV
   - Steel poles LV
   - Wooden cross arm LV
4. LV OH Conductor
   - Conductor LV (ABC)
   - Conductor LV (Bare)

5. Above Ground Services
   - Conductor LV service

Estimated Age	HV Poles and Poles Tops	Unit Cost Replacement	Total Installed in 2012	Unit Cost * Total Installed in 2012
80	Staked wooden poles HV	[redacted]	0	[redacted]
54	Wooden Poles HV	[redacted]	266	[redacted]
70	Concrete Poles HV	[redacted]	58	[redacted]
40	Steel Poles HV	[redacted]	0	[redacted]
45	Wooden Cross arm HV	[redacted]	0	[redacted]
70	Steel Cross arm HV	[redacted]	1384	[redacted]

SUM [c-i-c [redacted]]

1. Find $ proportion for each asset:
   Wooden Poles HV = (Unit Cost * Total Installed in 2012) / SUM of total Spent
   = [c-i-c [redacted]][4]

2. From the Asset Dollar Class by Year Sheet, Total Expenditure in 2012 for replacing HV Poles and Pole Tops was $3,328,272.

[4] JEN's unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.

Wooden Poles HV = Proportion obtained in No.1 * Total Expenditure in 2012 for HV Poles & Pole tops
= 0.38 * $3,328,272
= $1,262,743

3. Find weighted average life for each asset:

   Wooden Poles HV =
   (Total $value for Wooden Poles HV / Total Expenditure in 2012 for HV Poles & Pole Tops replacement) * Estimated Age
   = $1,262,743 / $3,328,272 * 54
   = 20.68
   Do the same for other assets: : Staked Wooden Poles HV, Concrete Poles HV, Steel Poles HV, Wooden Cross Arm HV, Steel Cross Arm HV

4. Sum all Weighted Avg life for this RAB type to get this RAB type Weighted Avg Life

HV Poles n Pole Tops	Individual weighted avg life
Staked wooden poles HV	0
Wooden poles HV	20.68
Concrete poles HV	5.84
Steel poles HV	0
Wooden cross arm HV	0
Steel cross arm HV	37.33

Weighted AVG life for HV Poles and Pole Tops = **63.87 years**

5. Proceed Step 1 – 6 for the other assets type as per RAB:
   - HV OH Conductor
   - LV Poles and Pole Tops
   - LV OH Conductor
   - Above ground services

6. Obtain weighted average life for this category:

		Average life per type	Weighted Average Life
Total Replacement Expenditure HV Pole & Pole Tops$ in 2012	$3,328,272	63.87	22.26408698
Total Replacement Expenditure HV OH Conductor in 2012	$1,859,190	60	11.68308702
Total Replacement Expenditure LV POLES AND POLE TOPS in 2012	$597,359	48.28	3.021079888
Total Replacement Expenditure LV OH Conductor in 2012	$2,723,319	60	17.1132444
Total Replacement Expenditure Above Ground	$1,039,971	60	6.535142557

Services in 2012			

SUM $ for this category	$9,548,110		
Total Weighted Average Life			60.61 years

2. ATTACHMENT 2

2.1 PROCEDURE 4.4.2 ASSET LIVES – ESTIMATED RESIDUAL SERVICE LIFE FEB 2014

Procedure: 4.4.2. Asset Lives - Estimated Residual Service (for SCS – services included)
For Category 1 – Overhead network assets less than 33kV (wires and poles)

The assets are (as per RAB):

6. HV Poles and Pole Tops
   - Staked wooden poles HV
   - Wooden poles HV
   - Concrete poles HV
   - Steel poles HV
   - Wooden cross arm HV
   - Steel cross arm HV
7. HV OH Conductor
   - Conductor HV (ABC)
   - Conductor HV (Bare)
8. LV Poles and Pole Tops
   - Staked wooden poles LV
   - Wooden poles LV
   - Concrete poles LV
   - Steel poles LV
   - Wooden cross arm LV
9. OH Conductor
   - Conductor LV (ABC)
   - Conductor LV (Bare)
10. Assets Above Ground
    - Conductor LV service

1. HV Poles and Pole Tops

   Find weighted average life for each of the component in this type.

   Staked wooden poles HV

   Estimated Age Life: 80 years
   Total installed from 1910 – 2012: 2,211

2. From 1910 – 2012, for each year
   Calculate: Remaining Years * Total installed

[redacted]

	2014	2014	2014	2014	2014
	1998	1999	2000	2001	2002
	15	14	13	12	11
	3	7	7	3	1
Total Installed Each Year	3	7	7	3	1
	80	80	80	80	80
Remaining Years	65	66	67	68	69
Total Installed * Remaining Years	195	462	469	204	69

3. From 1910 – 2012, for each year
   Sum from 1910 to 2012: Total installed * remaining years

4. Weighted average life for staked wooden poles HV:
   = Sum of (total installed * staked wooden poles HV) / Total asset installed
   = 77,777 / 2,211
   = 35 years

5. Repeat step 1 – 4 for other component in this type to get the weighted average life :
   - Wooden poles HV: 20 years
   - Concrete poles HV: 46 years
   - Steel poles HV: 13 years
   - Wooden cross arm HV: 7 years
   - Steel cross arm HV: 55 years

1. HV Poles and Pole Tops = $ 131,625,328

Remaining lives (obtained from above)	HV Poles and Poles Tops	Unit Cost Replacement	Total Installed up to 2012	Unit Cost * Total Installed up to 2012
35	Staked wooden poles HV	[redacted]	2,211	[redacted]
20	Wooden Poles HV	[redacted]	23,254	[redacted]
46	Concrete Poles HV	[redacted]	6,590	[redacted]
13	Steel Poles HV	[redacted]	12	[redacted]
7	Wooden Cross arm HV	[redacted]	23,852	[redacted]

Remaining lives (obtained from above)	HV Poles and Poles Tops	Unit Cost Replacement	Total Installed up to 2012	Unit Cost * Total Installed up to 2012
				[redacted]
55	Steel Cross arm HV	[c-i-c [redacted]]	25,521	[c-i-c [redacted]]

SUM = [c-i-c [redacted]][5]

7. Find $ proportion for each type:
   Staked Wooden Poles HV=[c-i-c [redacted]]

8. Find each asset $ value from each type from HV Poles and Pole Tops from Total Replacement Expenditure Up to 2012 = $131,625,328

   Staked Wooden Poles HV = 0.048 * $131,625,328
   = $6,427,101

   Do the same for other assets: Wooden Poles HV, Concrete Poles HV, Steel Poles HV, Wooden Cross Arm HV, Steel Cross Arm HV

9. Find weighted average life for each asset:

   For example in Type A
   Staked Wooden Poles HV =
   (Total $value for Wooden Poles HV / Total RAB Value) * Assigned Age
   = $ 6,427,101 / $ 131,625,328 * 35
   = 1.70
   Do the same for other assets: : Wooden Poles HV, Concrete Poles HV, Steel Poles HV, Wooden Cross Arm HV, Steel Cross Arm HV

10. Sum all Weighted Avg life for this RAB type to get this RAB type Weighted Avg Life

[5] JEN's unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.

HV Poles n Pole Tops	Individual weighted avg life
Staked wooden poles HV	1.7090
Wooden poles HV	10.2710
Concrete poles HV	6.6946
Steel poles HV	0.00344
Wooden cross arm HV	0.9868
Steel cross arm HV	8.2962

Weighted Average remaining lives for this type = 27.96 years

11. Proceed Step 1 – 6 for the other assets type as per RAB:
    - HV OH Conductor
    - LV Poles and Pole Tops
    - LV OH Conductor
    - Above ground services

		Average life per type	Weighted Average Life
Total RAB HV Pole & Pole Tops$	$131,625,328	27.96126996	11.52745792
Total RAB HV OH Conductor	$50,602,498	51	8.083125451
Total RAB LV POLES AND POLE TOPS	$62,926,291	20.35217636	4.01125414
Total RAB LV OH Conductor	$74,119,339	33.8042392	7.847654786
Total RAB Above Ground Services	$10,596,751	29	0.931596041

SUM $ for this category	$319,273,456		
Total Weighted Residual Service Life for DRAB1501			31.46 years

12. Obtain weighted average life for this category:

3. ATTACHMENT 3

See attached Microsoft Excel spreadsheet titled: ***JEN – EBT allocation model – FINAL – 30 Apr 14 – AER***

Jemena Electricity Networks (Vic) Ltd

Response to the economic benchmarking Regulatory Information Notice for the 2006-13 regulatory years

Annexure 4

Financial audit opinion and review report

Confidential

30 April 2014

Jemena Electricity Networks (Vic) Ltd

Response to the economic benchmarking Regulatory Information Notice for the 2006-13 regulatory years

Annexure 5

Non-financial audit report

Public

30 April 2014

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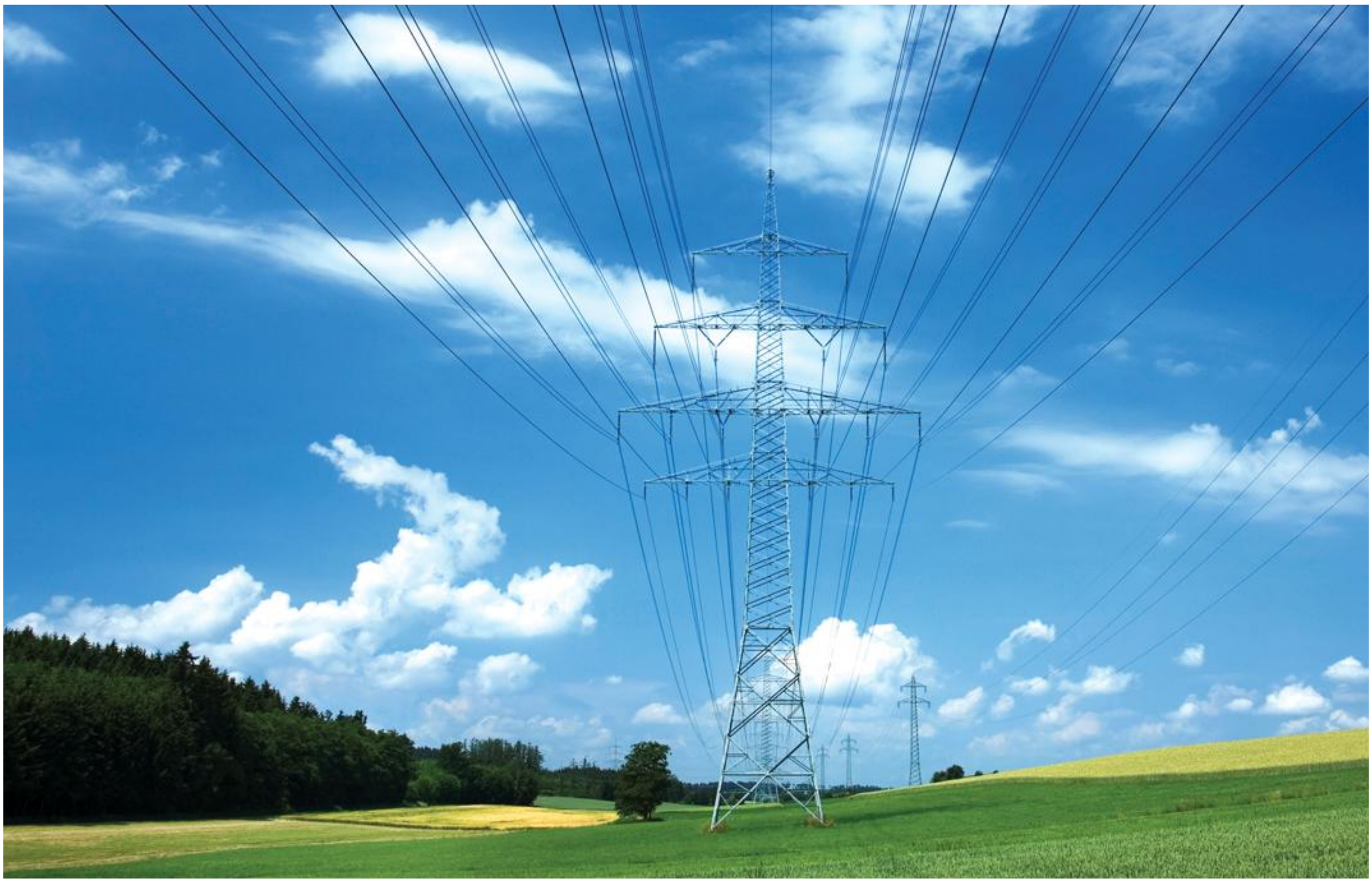
Jemena Electricity Networks

Review of Economic Benchmarking Non-financial Information

2 April 2014



PARSONS BRINCKERHOFF

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PARSONS BRINCKERHOFF

Reviewer's Statement

Parsons Brinckerhoff reviewed the Economic Benchmarking Regulatory Information Notice (RIN) non-financial information and Basis of Preparation prepared by Jemena Electricity Networks Pty Ltd for the Australian Energy Regulator for the regulatory years 2009 to 2013.

Parsons Brinckerhoff meets the requirements of "Class of person to conduct the audit" as outlined in Appendix D, paragraph 2.2 of the RIN.

This report has been prepared in accordance with the requirements outlined in Appendix D of the RIN. The review was undertaken as a 'Limited Assurance Audit' as required by the RIN and described in ASAE3000.

The reviewer's responsibility is to assess whether the non-financial information has been presented fairly in accordance with the requirements of the RIN and Jemena's Basis of Preparation. In doing this, the reviewer performed procedures to obtain evidence about the information. The procedures used depended on the reviewer's judgment, including the assessment of the risks of material misstatement at the disclosure level, whether due to fraud or error. In making the risk assessments, the auditor considered internal controls, system controls relating to the preparation and fair presentation of the estimates and disclosures made in the RIN in order to design review procedures that are appropriate in the circumstances.

The reviewer concludes that nothing has come to the reviewers' attention that causes it to believe that the historical non-financial information is not, in all material respects, presented fairly and in accordance with the requirement of the RIN and Jemena's Basis of Preparation.

Yours sincerely

Peter Walshe
Principal Consultant
Parsons Brinckerhoff Australia Pty Limited

Contents

Abbreviations

ACS	Alternative Control Services
BoP	Basis of Preparation document
DNSP	Distribution Network Service Provider
JEN	Jemena Electricity Networks (Vic) Ltd
MED	Major Event Day
NMI	National Meter Identifier
NSP	Network Service Provider
OMS	Outage Management System
Pf	Power factor
PV	Photovoltaic (with regard to embedded energy generation)
RAB	Regulated Asset Base
RIN	Regulatory Information Notice
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
TMED	Threshold Major Event Day
TNSP	Transmission Network Service Provider (e.g. SP AusNet)
TOU	Time of Use
ZSS	Zone Substation

1. Introduction

The Australian Energy Regulatory (AER) issued a Regulatory Information Notice (RIN) to Jemena Electricity Networks (Vic) Ltd (JEN) on the 28 November 2013. The RIN requires JEN to submit information set out in Appendix A of the RIN (the Economic Benchmarking templates) and prepared according to the instructions and definitions set out in Appendix B of the RIN ("Economic benchmarking RIN for distribution network service providers – Instructions and Definitions).

The non-financial information submitted by JEN is required to be reviewed by an independent party who meets the requirements set out in Appendix D of the RIN. Parsons Brinckerhoff satisfies the requirements of Section 2.2 of Appendix D of the RIN and was engaged by JEN to undertake a review of the non-financial information.

1.1 Scope of review

Parsons Brinckerhoff undertook the review of the Economic Benchmarking (EB) RIN non-financial information for the regulatory years 2009 to 2013[1], in accordance with appendix D of the RIN. The review was undertaken as a 'Limited Assurance Audit' as required by the RIN and described in ASAE3000. This included:

i. A review of the Basis of Preparation document required to be prepared under the RIN.

ii. An review of non-financial information in worksheets titled[2]:
   - 4. Assets (RAB)
   - 5. Operational data
   - 6. Physical assets
   - 7. Quality of services
   - 8. Operating environment

iii. Providing a conclusion as to whether or not anything has come to the Auditor's attention that causes it to believe that the historical non-financial information is not, in all material respects, presented fairly in accordance with the requirements of the RIN and JEN's Basis of Preparation.

1.2 Our approach

To achieve the outcome required by the RIN, Parsons Brinckerhoff's undertook this review in two parts:

- a desktop review to assess whether the NSP's Basis of Preparation accords with the RIN Instructions and Definitions[3]

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1 NB: Information contained within all RIN worksheets for regulatory years 2006, 2007 and 2008 are out of scope for the purposed of this review.

2 Parsons Brinckerhoff noted that worksheets 2. Revenue and 3. Opex do not contain any non-financial information and hence were excluded from this review scope

3 AER, 2013, Economic benchmarking RIN for distribution network service providers Instructions and Definitions

- an onsite review (including interviews) to assess whether the non-financial information contained in the worksheets was prepared in a manner that was consistent with the Basis of Preparation.

The desktop review involved:

- assessing whether or not definitions in the Basis of Preparation aligned to the definitions set out in the RIN
- assessing whether or not the methodology described in the Basis of Preparation aligned with the instructions set out in the RIN
- examining the excel spreadsheet templates for inconsistencies in data and/or trends, and whether those inconsistencies reflected the methodology set out in the Basis of Preparation.

The onsite review involved:

- clarification with key staff of the findings of the desktop review to determine if the data was generated in accordance with the RIN Instructions and Definitions
- discussion of any non-financial information that was estimated
- limited sampling of data in JEN's systems to confirm that the non-financial information is consistent with information held in those systems.

This also enabled verification that the data was prepared in a manner that was consistent with the Basis of Preparation. Data sources sighted are listed in section 2 of this document. The Parsons Brinckerhoff review team also sighted the numerous spreadsheets and databases which are identified within the Basis of Presentation document and which were used by the interviewees to derive the RIN data. The most important of these are identified in Table 2.1 and Table 2.2 of this report.

Parsons Brinckerhoff's audit approach and subsequent report complied with the requirements outlined in the Economic Benchmarking RIN and complied with the requirements of ASAE 3000[4] for a limited assurance audit review.

1.3 Information provided for review

Initial and revised information was presented as shown in Table 1.1. Initial review findings were basis on an assessment of the initial information. Jemena subsequently revised the information. The final review findings reflect the revised information.

[4] Assurance Engagements Other than Audits or Reviews of Historical Financial Information

Table 1.1 Information provided

Document
Initial
Basis of preparation for actual information, V0.1 24 February 2014 draft
Basis of preparation for estimated information, V0.1 24 February 2014 draft
RIN B - Final RIN B DNSP template - Estimated information HK 19 FEB 14.xlsx
RIN B - Final RIN B DNSP template - Actual information HK 19 FEB 14.xlsx
RIN B - Final RIN B DNSP template - Consolidated information HK 19 FEB 14.xlsx
Revised
Response to CY2013 economic benchmarking Regulatory Information Notice, Basis of Preparation, Information CY2006 to CY2013, 3 March 2014
Final JEN economic benchmarking RIN - Estimated information 3Mar14.xlsx
Final JEN economic benchmarking RIN - Actual information 3Mar14.xlsx
Final JEN economic benchmarking RIN - Consolidated information 3Mar14.xlsx

2. Information sources

JEN used a number of business systems and planning reports as a basis for gathering information and converting it into the format required by the RIN. During the review, Parsons Brinckerhoff identified the following suite of information systems and documentation that were relied upon by JEN.

The scope of the review did not include reviewing the systems and procedures, so accordingly Parsons Brinckerhoff undertook the review on the assumption that the information contained in these systems was fit for purpose and the review concentrated on the use of correct definitions and the assumptions and estimates used to close information gaps. Our reviewers also sought to ascertain, where possible within the constraints of the review process, whether the source information was the most appropriate information to use to derive the information to populate the RIN tables.

Data sources - Information systems

Table 2.1 Information systems relevant to this review

JEN information system	Function
COGNOS	A front-end reporting tool/application used to extract data from OMS, using prewritten filters/scripts to produce defined report formats, and output the data into various formats including PDF, Excel and text files. COGNOS is not a database and therefore does not store data.
Customer Information System (CIS)	Source of customer number data, including customer geographical locations and network connection points that is input into the Network Model and used by OMS to calculate the number of customers affected by each outage.
Geographical Information System (GIS)	A live model of the network and represents the network at the current point in time.
Interval Meter Store (IMS)	A system that captures the data from wholesale meters and aggregates the information.
OSI Pi	Proprietary software name of a data collection system used by JEN
Outage Management System (OMS)	Repository for all outage information, including outage dates and times, the number of customers affected, restoration dates and times and restoration stages. It records switching data directly from SCADA and receives data from non-telemetered devices from operators changing status of switches. Customer numbers are built into OMS via the Network Model. Complex switching records can be cancelled and recreated (if corrections are required) and logs of all corrections are retained.
SAP ISU	Source of customer number data, including customer geographical locations and network connection points that is input into the Network Model and used by OMS to calculate the number of customers affected by each outage. SAP is the database of customers having smart meters installed as part of the Advanced Metering Infrastructure program.
Vegetation management system (VMS)	Data is collected in the field and entered into data collection devices and is then loaded into the VMS. The VMS records the number of maintenance spans but not the number of trees per maintenance span.

Other data sources provided for review

Table 2.2 Other data sources relevant to this review sighted by the reviewers

Template number	File names
Template 4	Documents JEN PR 0114, JEN PR 0506, JEN Asset Lives – FINAL – 18 Feb 14. xlsx
Template 5	Spreadsheet “Support Customer Numbers RIN B_Table 5.2.`.xlsx” AER email “Customer numbers - economic benchmarking RIN” dated 21/2/14
Template 6	
Template 7	Audit Report “2193222A-RPT0001 – RIN Audit 2012 FINAL” Spreadsheet “MED 2006-2012 based on 2013 MED threshold.xlsx”
Template 8	

3. Our findings

This section sets out each table/template and the information required by the RIN. We detail the issues we found and whether or not we consider them to be material.

The methodology used to assess the data is described in section 1.2 and the information sources and documents we reviewed are described in section 2.

3.1 Template 4 - Assets RAB

Table 4.4 Asset Lives

Variable Code	Table 4.4 Asset lives	Unit
	Table 4.4.1 Asset Lives – estimated service life of new assets	
DRAB1401	Overhead network assets less than 33kV (wires and poles)	years
DRAB1402	Underground network assets less than 33kV (cables)	years
DRAB1403	Distribution substations including transformers	years
DRAB1404	Overhead network assets 33kV and above (wires and towers / poles etc)	years
DRAB1405	Underground network assets 33kV and above(cables, ducts etc)	years
DRAB1406	Zone substations and transformers	years
DRAB1407	Meters	years
DRAB1408	“Other” assets with long lives	years
DRAB1409	“Other” assets with short lives	years
	Table 4.4.2 Asset Lives – estimated residual service life	
DRAB1501	Overhead network assets less than 33kV (wires and poles)	years
DRAB1502	Underground network assets less than 33kV (cables)	years
DRAB1503	Distribution substations including transformers	years
DRAB1504	Overhead network assets 33kV and above (wires and towers / poles etc)	years
DRAB1505	Underground network assets 33kV and above (cables, ducts etc)	years
DRAB1506	Zone substations and transformers	years
DRAB1507	Meters	years
DRAB1508	“Other” assets with long lives	years
DRAB1509	“Other” assets with short lives	years

Key RIN requirements for this table:

1. Report asset lives for all RAB assets in accordance with variables shown above.
2. Table 4.4.1 - Report service lives of new assets as the estimated period after installation during which the asset is capable of delivering the same effective service as it could at its installation date.
3. Table 4.4.2 - Report a current estimation of the weighted average remaining time expected that an asset class (as per DRAB1401 to DRAB1409 incl.) will deliver the same effective service as that asset class did at its installation date.

4. When completing the templates for regulatory years prior to the 2013 Regulatory Year, if JEN can provide Actual Information[5] for the life of new assets it must do so; otherwise provide Estimated Information[6].

Initial review findings:

1. Definitions need to be consistent with the RIN:
    a) In tables 4.4.1 and 4.4.1 for ACS, JEN reported information against DRAB1401/DRAB1501 Overhead network assets less than 33kV (wires and poles), DRAB1402/DRAB1502 Underground network assets less than 33kV (cables) and DRAB1408/DRAB1508 “Other” assets with long lives. The latter is for public lighting, which is correctly classified as an ACS. The first two are the same values as reported for SCS. JEN was unable to ascertain whether any new ACS had actually been installed in the years 2009 to 2013, such as back-up feeders, but considered it unlikely. Therefore all other items under ACS other than for public lighting should be 0. As such the following variables are considered to be non-compliant for ACS:
        i) DRAB1401 and DRAB1402
        ii) DRAB1501 and DRAB1502
    b) According to the RIN definition, Network services excludes connection services. Attachments 1 and 2 of JENs BoP indicated that Conductor LV service has been included in the Network Service data. As such, the following variables are considered to be non-compliant for Network services:
        i) DRAB1401 and DRAB1402
        ii) DRAB1501 and DRAB1502
2. The BoP defines the source of the data for 2011 and 2012 as RIN A, which is correct in that these RINs are the only place the information is currently recorded. They are however, not the “source”. As the BoP has not appropriately defined the source of the data, it is considered non-compliant.

Final review findings:

1. All initial review findings were addressed in the revised documents.
2. We did not find reason to believe that the data contained in RIN tables 4.4.1 and 4.4.2 has not been presented fairly in all material respects.
3. We did not find reason to believe that the Basis of Preparation for Tables 4.4.1 and 4.4.2 has not been presented fairly in all material respects.

[5] As per RIN Definition p42

[6] As per RIN Definition p42

3.2 Template 5 - Operational Data

Table 5.1 Energy Delivery

Variable Code	Table 5.1 Energy delivery	Units
DOPED01	***Total energy delivered***	GWh
	Table 5.1.1 Energy grouping - delivery by chargeable quantity	
DOPED0201	Energy Delivery where time of use is not a determinant	GWh
DOPED0202	Energy Delivery at On-peak times	GWh
DOPED0203	Energy Delivery at Shoulder times	GWh
DOPED0204	Energy Delivery at Off-peak times	GWh
DOPED0205	Controlled load energy deliveries	GWh
DOPED0206	Energy Delivery to unmetered supplies	GWh
	Table 5.1.2 Energy - received from TNSP and other DNSPs by time of receipt	
DOPED0301	Energy into DNSP network at On-peak times	GWh
DOPED0302	Energy into DNSP network at Shoulder times	GWh
DOPED0303	Energy into DNSP network at Off-peak times	GWh
DOPED0304	Energy received from TNSP and other DNSPs not included in the above categories	GWh
	Table 5.1.3 Energy - received into DNSP system from embedded generation by time of receipt	
DOPED0401	Energy into DNSP network at On-peak times from non-residential embedded generation	GWh
DOPED0402	Energy into DNSP network at Shoulder times from non-residential embedded generation	GWh
DOPED0403	Energy into DNSP network at Off-peak times from non-residential embedded generation	GWh
DOPED0404	Energy received from embedded generation not included in above categories from non-residential embedded generation	GWh
DOPED0405	Energy into DNSP network at On-peak times from residential embedded generation	GWh
DOPED0406	Energy into DNSP network at Shoulder times from residential embedded generation	GWh
DOPED0407	Energy into DNSP network at Off-peak times from residential embedded generation	GWh
DOPED0408	Energy received from embedded generation not included in above categories from residential embedded generation	GWh
	Table 5.1.4 Energy grouping - customer type or class	
DOPED0501	Residential customers energy deliveries	GWh
DOPED0502	Non-residential customers not on demand tariffs energy deliveries	GWh
DOPED0503	Non-residential low voltage demand tariff customers energy deliveries	GWh
DOPED0504	Non-residential high voltage demand tariff customers energy deliveries	GWh
DOPED0505	Other Customer Class Energy Deliveries	GWh

Key RIN requirements for this table:

1. Report the energy transported out of JEN’s network in accordance with variables shown above.
2. Energy reported must be the actual energy delivered as metered or estimated at the customer charging location rather than the import location from the TNSP.
3. Where Actual Information is unavailable for the most recent reporting period, energy delivery data for that period may be reported on an accrual basis.

Initial review findings:

1. In Table 5.1.3 JEN has not provided information for variables DOPED0401, DOPED0402 and DOPED0403, marking these cells as 0. JEN state that they do not have tariffs for embedded generation that include on-peak, shoulder or off-peak components; hence they do not record this information. The reviewer notes that the definition is unclear whether the periods are in respect of tariffs for embedded generators or for the period specified in other tariffs. The reviewer accepts JEN's interpretation that the former applies.
2. Parsons Brinkerhoff notes that the Instructions and Definitions (p.29) state that JEN must only report energy against DOPED0404 where it is not possible to allocate the energy received into on-peak, shoulder and off-peak time. The reviewer notes that the definition is unclear whether the periods are in respect of tariffs for embedded generators or for the period specified in other tariffs. The reviewer accepts JEN's interpretation that the former applies.

Final review findings:

1. We did not find reason to believe that the data in the RIN tables 5.1.1, 5.1.2, 5.1.3 and 5.1.4 has not been presented fairly in all material respects.
2. We did not find reason to believe that the Basis of Preparation for tables 5.1.1, 5.1.2, 5.1.3 and 5.1.4 has not been presented fairly in all material respects.

Table 5.2 Customer Numbers

Variable Code	5.2 Customer numbers	Units
	Table 5.2.1 Distribution customer numbers by customer type or class	
DOPCN0101	Residential customer numbers	number
DOPCN0102	Non-residential customers not on demand tariff customer numbers	number
DOPCN0103	Low voltage demand tariff customer numbers	number
DOPCN0104	High voltage demand tariff customer numbers	number
DOPCN0105	Unmetered Customer Numbers	number
DOPCN0106	Other Customer Numbers	number
DOPCN01	***Total customer numbers***	number
	Table 5.2.2 Distribution customer numbers by location on the network	
DOPCN0201	Customers on CBD network	number
DOPCN0202	Customers on Urban network	number
DOPCN0203	Customers on Short rural network	number
DOPCN0204	Customers on Long rural network	number
DOPCN02	***Total customer numbers***	number

Key RIN requirements for this table:

1. Report the average number of active NMIs (except for Unmetered Customer Numbers) in JEN's network in that year. Each NMI is to be counted as a separate customer.
2. The average is to be calculated as an average of the number of customers on the first day of the Regulatory Year and the last day of the Regulatory Year, counting both energised and de-energised customers but excluding extinct NMIs.
3. For unmetered customers the Customer Numbers reported shall be the sum of connections (excluding Public lighting) in JEN's network that do not have an NMI and the energy usage shall be calculated using an assumed load profile (e.g. bus shelters).

Initial review findings:

1. In Table 5.2.1 JEN has estimated the values of DOPCN0101 to DOPCN0104 based on the percentage split across tariff classes for active NMIs only. An assumption has been made that the number of de-energised NMIs would be evenly distributed according to the same proportion as active NMIs. Though this assumption is questionable given that most de-energised NMIs could be expected to be associated with move-in/move-out of residential customers, Parsons Brinckerhoff tested the sensitivity of assigning the same proportion for de-energised and found it to be immaterial. The BoP does not include the assumption regarding the split by active NMIs, which should be included.
2. In table 5.2.2, JEN's data shows that DOPCN02 = DOPCN01 – DOPCN0105, that is JEN has taken the view that DOPCN02 doesn't include unmetered supplies. Similarly variables DOPCN0201 to DOPCN0204 do not include unmetered supplies. This does not align with the definitions in the RIN, which includes the words "customers of all types and classes". Hence variables DOPCN0201 to DOPCN0204 and DOPCN02 are non-compliant with the RIN.

Final review findings:

1. All initial review findings were addressed in the revised documents.
2. We did not find reason to believe that the data in the RIN tables 5.2.1 has not been presented fairly in all material respects.
3. We did not find reason to believe that the Basis of Preparation for tables 5.2.1 and 5.2.2 has not been presented fairly in all material respects.

Table 5.3 System Demand

Variable Code	5.3 System demand	Units
	Table 5.3.1 Annual system maximum demand characteristics at the zone substation level – MW measure	
DOPSD0101	Non-coincident Summated Raw System Annual Maximum Demand	MW
DOPSD0102	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	MW
DOPSD0103	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	MW
DOPSD0104	Coincident Raw System Annual Maximum Demand	MW
DOPSD0105	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	MW
DOPSD0106	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	MW
	Table 5.3.2 Annual system maximum demand characteristics at the transmission connection point – MW measure	
DOPSD0107	Non-coincident Summated Raw System Annual Maximum Demand	MW
DOPSD0108	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	MW
DOPSD0109	Non-coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	MW
DOPSD0110	Coincident Raw System Annual Maximum Demand	MW
DOPSD0111	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	MW
DOPSD0112	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	MW
	Table 5.3.3 Annual system maximum demand characteristics at the zone substation level – MVA measure	
DOPSD0201	Non–coincident Summated Raw System Annual Maximum Demand	MVA
DOPSD0202	Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	MVA
DOPSD0203	Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50%	MVA

	POE	
DOPSD0204	Coincident Raw System Annual Maximum Demand	MVA
DOPSD0205	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	MVA
DOPSD0206	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	MVA
	Table 5.3.4 Annual system maximum demand characteristics at the transmission connection point – MVA measure	
DOPSD0207	Non–coincident Summated Raw System Annual Maximum Demand	MVA
DOPSD0208	Non–coincident Summated Weather Adjusted System Annual Maximum Demand 10% POE	MVA
DOPSD0209	Non–coincident Summated Weather Adjusted System Annual Maximum Demand 50% POE	MVA
DOPSD0210	Coincident Raw System Annual Maximum Demand	MVA
DOPSD0211	Coincident Weather Adjusted System Annual Maximum Demand 10% POE	MVA
DOPSD0212	Coincident Weather Adjusted System Annual Maximum Demand 50% POE	MVA
	Table 5.3.5 Power factor conversion between MVA and MW	
DOPSD0301	Average overall network power factor conversion between MVA and MW	Factor
DOPSD0302	Average power factor conversion for low voltage distribution lines	Factor
DOPSD0303	Average power factor conversion for 11 kV lines	Factor
DOPSD0304	Average power factor conversion for SWER lines	Factor
DOPSD0305	Average power factor conversion for 22 kV lines	Factor
DOPSD0306	Average power factor conversion for 33 kV lines	Factor
DOPSD0307	Average power factor conversion for 66 kV lines	Factor
DOPSD0308	Average power factor conversion for 132 kV lines	Factor
DOPSD0309	Average power factor conversion for 110 kV lines	Factor
	Table 5.3.6 Demand supplied (for customers charged on this basis) – MW measure	
DOPSD0401	Summated Chargeable Contracted Maximum Demand	MW
DOPSD0402	Summated Chargeable Measured Maximum Demand	MW
	Table 5.3.7 Demand supplied (for customers charged on this basis) – MVA measure	
DOPSD0403	Summated Chargeable Contracted Maximum Demand	MVA
DOPSD0404	Summated Chargeable Measured Maximum Demand	MVA

Key RIN requirements for this table:

1. Provide back cast system demand data in accordance with the instructions and definitions in Chapters 5 and 9 of the RIN Instructions and Definitions sufficient to populate the RIN tables shown above.

Initial review findings:

1. Some estimated data should be entered as ACTUAL data:
    a) For years 2008-2013 DOPSD0104 is actual data extracted from JEN's information systems, however the time of the coincident maximum demand at zone substations is assumed to occur at the same time as the coincident maximum demand at transmission connection points. This is a reasonable assumption and should be included in the BoP.
    b) JEN does not record MVA and hence DOPSD0201, DOPSD0204, DOPSD0207 and DOPSD0210 are calculations made by multiplying MW by power factor (Pf). As both MW and Pf are actual data, these variables should be considered ACTUAL data.
2. DOPSD0201 BoP assumptions terminology is misleading. 'MVAr MD' should be 'MVAr at the time of MW MD'.

3. In table 5.3.5, when providing data for DOPS0301 “Average overall network power factor conversion between MVA and MW”, and DOPS0303, DOPS0305 and DOPS0307 being the power factors for 11kV, 22kV and 66kV respectively, JEN notes that it has provided the power factor at the time of system coincident peak demand at transmission connection points (DOPS0301 and DOPS0307) or at the time of non-coincident MW MD, measured at secondary voltage at the zone substation (DOPS0303 and DOPS0305). Hence the data does not represent the average overall network power factor as in all instances it is at the time of maximum demand.
4. Additionally for DOPS0301, the data provided is calculated from actual values of MW and MVAr, with an assumption about the value of capacitor banks in operation at the time. As such, the data should be considered ACTUAL data, and the assumption recorded in the BoP. All other data is properly classified as ESTIMATED.
5. In checking that the power factors provided at DOPS0301 represent MVA dived by MW, we found that the value provided for 2009 was 0.93 rather than 0.94. The data was recorded in the spreadsheet to 15 significant figures. Divergence was noted in the 3rd significant figure for other years, indicating a difference in underlying data rather than in rounding errors.
6. JEN does not record data that could be used to provide an estimate of the value of DOPS0302 “Average power factor conversion for low voltage distribution lines”. The power factor is assumed to be 0.8 lagging as per the limit specified in the distribution code for customers supply voltage less than 6.6kV. As this represents a lower limit rather than an estimate, the values provided for DOPS0302 are considered to not comply with the RIN definition.
7. As a result of points 3, 4, 5 and 6 above, we find that there is reason to believe that the data contained in tables 5.3.5 may contain a material difference to actual data.

Final review findings:

1. All initial review findings were addressed in the revised documents.
2. We did not find reason to believe that the data in the tables 5.3.1, 5.3.2, 5.3.3, 5.3.4, 5.3.5, 5.3.6 and 5.3.7 has not been presented fairly in all material respects.
3. We did not find reason to believe that the Basis of Preparation for tables 5.3.1, 5.3.2, 5.3.3, 5.3.4, 5.3.5, 5.3.5, 5.3.6 and 5.3.7 has not been presented fairly in all material respects.

3.3 Template 6 - Physical Assets

Table 6.1 Network Capacities Variables

Variable Code	Table 6.1 Network Capacities Variables	Unit
	Circuit length	
	Table 6.1.1 Overhead network length of circuit at each voltage	
DPA0101	Overhead low voltage distribution	km
DPA0102	Overhead 11 kV	km
DPA0103	Overhead SWER	km
DPA0104	Overhead 22 kV	km
DPA0105	Overhead 33 kV	km
DPA0106	Overhead 66 kV	km
DPA0107	Overhead 132 kV	km
DPA0108	Other overhead voltages	km
DPA01	***Total overhead circuit km***	km
	Table 6.1.2 Underground network circuit length at each voltage	
DPA0201	Underground low voltage distribution	km
DPA0202	Underground 11 kV	km
DPA0203	Underground 22 kV	km
DPA0204	Underground 33 kV	km
DPA0205	Underground 66 kV	km
DPA0206	Underground 132 kV	km
DPA0207	Other underground voltages	km
DPA02	***Total underground circuit km***	km
	Circuit Capacity MVA	
	Table 6.1.3 Estimated overhead network weighted average MVA capacity by voltage class	
DPA0301	Overhead low voltage distribution	MVA
DPA0302	Overhead 11 kV	MVA
DPA0303	Overhead SWER	MVA
DPA0304	Overhead 22 kV	MVA
DPA0305	Overhead 33 kV	MVA
DPA0306	Overhead 66 kV	MVA
DPA0307	Overhead 132 kV	MVA
DPA0308	Other overhead voltages	MVA
	Table 6.1.4 Estimated underground network weighted average MVA capacity by voltage class	
DPA0401	Underground low voltage distribution	MVA
DPA0402	Underground 11 kV	MVA
DPA0403	Underground 22 kV	MVA
DPA0404	Underground 33 kV	MVA
DPA0405	Underground 66 kV	MVA
DPA0406	Underground 132 kV	MVA
DPA0407	Underground SWER	MVA
DPA0408	Other underground voltages	MVA

Key RIN requirements for this table:

1. Report against the capacity variables for the entire network as defined by the RIN Instructions and Definitions, which includes quantities and capacities of physical assets.

Initial review findings:

1. JEN has not provided data for variable DPA0303 “Estimated overhead network weighted average MVA capacity – Overhead SWER”. As this variable is coded “yellow”, a non-zero value should have been estimated for 2009 to 2013, when all SWER was removed. It is Parsons Brinkerhoff’s opinion that the design rating of the SWER could be used to provide an estimate of the required values. Hence DPA0303 is considered non-compliant with the RIN on the basis that no data is inserted.
2. When providing data for table 6.1.4, JEN assumed that all two-core underground cables, i.e. single phase cables, provide connection services and are therefore not included in the data. This assumption appears reasonable and should be noted in the BoP.

Final review findings:

1. All initial review findings were addressed in the revised documents.
2. We did not find reason to believe that the data in the RIN tables 6.1.1, 6.1.2, 6.1.3 and 6.1.4 has not been presented fairly in all material respects.
3. We did not find reason to believe that the Basis of Preparation for tables 6.1.1, 6.1.2, 6.1.3 and 6.1.4 has not been presented fairly in all material respects.

Table 6.2 Transformer Capacities Variables

Variable Code	6.2 Transformer Capacities Variables	Unit
	Table 6.2.1 Distribution transformer total installed capacity	
DPA0501	Distribution transformer capacity owned by utility	MVA
DPA0502	Distribution transformer capacity owned by High Voltage Customers	MVA
DPA0503	Cold spare capacity included in DPA0501	MVA
	Table 6.2.2 Zone substation transformer capacity	
DPA0601	Total installed capacity for first step transformation where there are two steps to reach distribution voltage	MVA
DPA0602	Total installed capacity for second step transformation where there are two steps to reach distribution voltage	MVA
DPA0603	Total zone substation transformer capacity where there is only a single step transformation to reach distribution voltage	MVA
DPA0604	Total zone substation transformer capacity	MVA
DPA0605	Cold spare capacity of zone substation transformers included in DPA0604	MVA

Key RIN requirements for this table:

1. Report the total installed transformer capacity in the final level of voltage transformation, excluding intermediate voltage transformation capacity (e.g. 132 kV or 66 kV to 22 kV or 11 kV).
2. The capacity measure is the normal nameplate continuous capacity / rating (including forced capacity or other factors used to improve capacity).

3. Cold spare capacity is the number of transformers owned by JEN but not in use, incorporating both spare capacity and cold capacity.

Initial review findings:

1. For variable DPA0502, the BoP includes an inconsistency in the power factor used, 0.85 and 0.9 both stated.
2. When providing data for DPA0503, JEN has not included spare capacity (which includes spare assets, on site, or in the store, where physical movement and / or making of connections would require manual intervention at the site of use). This also impacts on the reported Variable DPA0501. Hence, DPA0501 and DPA0503 are considered non-compliant with the RIN. JEN confirm that they do not have spare ZSS transformers and hence the same issue does not apply to DPA0601 and DPA0605, which are consider compliant.
3. For all variables in Table 6.2.2, the BoP has not appropriately defined the source of the data for ACTUAL and is considered non-compliant with the RIN.

Final review findings:

1. All initial review findings were addressed in the revised documents.
2. We did not find reason to believe that the data in the RIN tables 6.2.1 and 6.2.2 has not been presented fairly in all material respects.
3. We did not find reason to believe that the Basis of Preparation for tables 6.2.1 and 6.2.2 has not been presented fairly in all material respects.

Table 6.3 Public Lighting

Variable Code	6.3 Public lighting	Unit
DPA0701	Public lighting luminaires	Number
DPA0702	Public lighting poles	Number

Key RIN requirements for this table:

1. Report the total number of public lighting luminaires and public lighting poles, including both assets owned by JEN and assets operated and maintained on behalf of other owners.
2. Pole counts are only to include poles used exclusively for public lighting.

Initial review findings:

1. In providing estimated data for DPA0702 “Public lighting poles” for 2008 to 2010, JEN has used actual information about the number of new installations and removals to calculate the number of poles. Because the calculation uses actual data, the values provided for DPA0702 should also be considered as ACTUAL data.

Final review findings:

2. We did not find reason to believe that the Basis of Preparation and data for table 6.3 has not been presented fairly in all material respects.

3.4 Template 7 – Quality of Service

Table 7.1 Reliability

Variable Code	Table 7.1 Reliability	Unit
	Table 7.1.1 Inclusive of MEDs	
DQS0101	Whole of network unplanned SAIDI	minutes/customer
DQS0102	Whole of network unplanned SAIDI excluding excluded outages	minutes/customer
DQS0103	Whole of network unplanned SAIFI	interruptions/customer
DQS0104	Whole of network unplanned SAIFI excluding excluded outages	interruptions/customer
	Table 7.1.2 Exclusive of MEDs	
DQS0105	Whole of network unplanned SAIDI	minutes/customer
DQS0106	Whole of network unplanned SAIDI excluding excluded outages	minutes/customer
DQS0107	Whole of network unplanned SAIFI	interruptions/customer
DQS0108	Whole of network unplanned SAIFI excluding excluded outages	interruptions/customer

Key RIN requirements for this table:

1. Report reliability data in accordance with the definitions provided in the AER's STPIS unless otherwise specified.
2. For the purposes of calculating reliability, an interruption is any loss of electricity supply to a customer associated with an outage of any part of the electricity supply network, including generation facilities and transmission networks, of more than 0.5 seconds, including outages affecting a single premises.
3. The customer interruption starts when recorded by equipment such as SCADA or, where such equipment does not exist, at the time of the first customer call relating to the network outage.
4. An interruption may be planned or unplanned, momentary or sustained. Subsequent interruptions caused by network switching during fault finding are not to be included.
5. An interruption ends when supply is again generally available to the customer.
6. An unplanned interruption is an interruption due to an unplanned event. An unplanned event is an event that causes an interruption where the customer has not been given the required Notice for the interruption or where the customer has not requested the outage.
7. Reliability information in tables 7.1.1 and 7.1.2 is only to be reported for unplanned interruptions.
8. Unplanned interruptions are as defined in the STPIS.
9. Whole of network SAIDI and SAIFI is the system-wide SAIDI and SAIFI. SAIDI and SAIFI for individual feeder categories is not required.
10. The MED threshold must be calculated for the 2013 Regulatory Year in accordance with the requirements in the STPIS. The MED threshold calculated for 2013 must then be applied as the MED threshold for Regulatory Years prior to 2013 for the purpose of calculating SAIDI and SAIFI exclusive of MEDs as per the STPIS.

Initial review findings:

1. In reviewing tables 7.1.1 and 7.1.2, we relied on the 2013 annual performance audit conducted by Parsons Brinckerhoff as it related to definitions, systems and processes.
2. No issues were found.

Final review findings:

1. We did not find reason to believe that the data in the RIN tables 7.1.1 and 7.1.2 has not been presented fairly in all material respects.
2. We did not find reason to believe that the Basis of Preparation for tables 7.1.1 and 7.1.2 has not been presented fairly in all material respects.

Table 7.2 Energy Not Supplied

Variable Code	Table 7.2 Energy not supplied	Unit
DQS0201	Energy Not Supplied (planned)	GWh
DQS0202	Energy Not Supplied (unplanned)	GWh
DQS02	Energy Not Supplied - Total	GWh

Key RIN requirements for this table:

1. Energy not supplied is an estimate of the energy that was not supplied as a result of customer interruptions.
2. JEN must estimate the raw (not normalized) energy not supplied due to unplanned customer interruptions based on average customer demand (multiplied by the number of customers interrupted and the duration of the interruption). Average customer demand must be determined from (in order of preference):
   a) average consumption of the customers interrupted based on their billing history
   b) feeder demand at the time of the interruption divided by the number of customers on the feeder
   c) average consumption of customers on the feeder based on their billing history
   d) average feeder demand derived from feeder Maximum Demand and estimated load factor divided by the number of customers on the feeder
3. Energy not supplied should be reported exclusive of the effect of Excluded Outages as defined in the RIN Instructions and Definitions.
4. When completing the templates for Regulatory Years subsequent to the 2013 Regulatory Year, if JEN can provide Actual Information for energy not supplied it must do so; otherwise JEN must provide Estimated Information.

Initial review findings:

1. For table 7.2, the BoP states that no assumption has been made; however JEN also states that the methodology includes an assumed load factor “calculated from ‘(feeder) average demand’ divided by (Feeder) Maximum Demand for the 12 month period as sourced from OSI Pi”. JEN to include this assumption in the BoP.
2. JEN also assumed that customers notified of a planned outage would shift 70% of their load to another time when supply was available. A factor of 0.3 was therefore applied to energy not supplied due to planned interruptions. This assumption does not appear unreasonable and should be included in the BoP.

Final review findings:

1. All initial review findings were addressed in the revised documents.

2. We did not find reason to believe that the data in the table 7.2 has not been presented fairly in all material respects.
3. We did not find reason to believe that the Basis of Preparation for table 7.2 has not been presented fairly in all material respects.

Table 7.3 System Losses

Variable Code	Table 7.3 System losses	Unit
DQS03	System losses	%

Key RIN requirements for this table:

1. System losses is the proportion of energy that is lost in distribution of electricity from the transmission network to JEN customers.
2. JEN must report distribution losses calculated as per the equation below.
3. Calculation of system losses:

$$system\ losses = \frac{\text{electricity imported} - \text{electricity delivered}}{\text{electricity delivered}} \times 100$$

4. Where:
   a) Electricity imported is the total electricity inflow into JEN's distribution network (including from Embedded Generation) minus the total electricity outflow into the networks of the adjacent connected distribution network service providers or the transmission network(s).
   b) Electricity delivered is the amount of electricity transported out of JEN's network to its customers as metered (or otherwise calculated) at the customer's connection. (This is a system wide figure not a feeder level figure).

Initial review findings:

1. No issues were found.

Final review findings:

1. We did not find reason to believe that the data in the RIN table 7.3 has not been presented fairly in all material respects.
2. We did not find reason to believe that the Basis of Preparation for table 7.3 has not been presented fairly in all material respects.

Table 7.4 Capacity Utilisation

Variable Code	Table 7.4 Capacity utilisation	Unit
DQS04	Overall utilisation	%

Key RIN requirements for this table:

1. Capacity utilisation is a measure of the capacity of zone substation transformers that is utilized each year.

2. JEN must report the sum of non-coincident Maximum Demand at the zone substation level divided by summation of zone substation thermal capacity.
3. For the purpose of this measure, thermal capacity is the rated continuous load capacity of the zone substation (with forced cooling or other capacity improving factors included if relevant). This must be the lowest of either the transformer capacity or feeder exit capacity of the zone substation. Feeder exit capacity should similarly be the continuous rating.

Initial review findings:

1. The data in table 7.4 DQS04 does not appear to be equal to the “Sum of non-coincident demand at the zone substation level (DOPSD0201) divided by the summation of zone substation thermal capacity (DPA0604 minus DPA0605)”. As DQS04 appears to not have been derived in accordance with the RIN instructions and definitions; we therefore cannot state that the data has been presented fairly in all material respects.
2. The BoP states that DQS04 is equal to the “Sum of non-coincident demand at the zone substation level (DOPSD0201) divided by the summation of zone substation thermal capacity (DPA0604)”. Although the cold spare capacity at DPA0605 is 0, the BoP should note that the correct value for zone substation thermal capacity is DPA0604 minus DPA0605.

Final review findings:

1. All initial review findings were addressed in the revised documents.
2. We did not find reason to believe that the data in the RIN tables 7.4 has not been presented fairly in all material respects.
3. We did not find reason to believe that the Basis of Preparation for table 7.4 has not been presented fairly in all material respects.

3.5 Template 8 - Operating Environment

Table 8.1 Density Factors

Variable Code	Table 8.1 Density factors	Unit
DOEF0101	Customer density	Customer / km
DOEF0102	Energy density	MWh/customer
DOEF0103	Demand density	kVA / customer

Key RIN requirements for this table:

1. Provide data in accordance with the following definitions:
   a) Customer density is the total number of customers divided by the route line length of the network.
   b) Energy density is the total MWh divided by the total number of customers of the network.
   c) Demand density is the kVA non-coincident maximum demand (at ZSS level) divided by the total number of customers of the network.

Initial review findings:

1. No issues were found.

Final review findings:

1. We did not find reason to believe that the data in the RIN table 8.1 has not been presented fairly in all material respects.
2. We did not find reason to believe that the Basis of Preparation for table 8.1 has not been presented fairly in all material respects.

Table 8.2 Terrain Factors

Variable Code	Table 8.2 Terrain factors	Unit
DOEF0201	Rural proportion	km
DOEF0202	Urban and CBD vegetation maintenance spans	Number of spans
DOEF0203	Rural vegetation maintenance spans	Number of spans
DOEF0204	Total vegetation maintenance spans	Number of spans
DOEF0205	Total number of spans	Number of spans
DOEF0206	Average urban and CBD vegetation maintenance span cycle	Years
DOEF0207	Average rural vegetation maintenance span cycle	Years
DOEF0208	Average number of trees per urban and CBD vegetation maintenance span	Trees
DOEF0209	Average number of trees per rural vegetation maintenance span	Trees
DOEF0210	Average number of defects per urban and CBD vegetation maintenance span	Defects
DOEF0211	Average number of defects per rural vegetation maintenance span	Defects
DOEF0212	Tropical proportion	Number of spans
DOEF0213	Standard vehicle access	km
DOEF0214	Bushfire risk	Number of spans

Key RIN requirements for this table:

1. Complete table in accordance with RIN definitions provided.
2. If JEN has Actual Information, it must report all years of available data. If JEN does not have Actual Information on the variables above, it must estimate data for the most recent Regulatory Year.
3. Where no data is available for DOEF0206 and DOEF0207 JEN is required to estimate five years of back cast data.
4. The average vegetation Maintenance Span Cycle can be calculated based on a simple average of all Maintenance Span Cycles.
5. Data for variables DOEF0208 to DOEF0214 inclusive is to be provided using the processes described in the RIN Instructions and Definitions.

Initial review findings:

1. The average number of trees per maintenance span is defined in the RIN as the "estimated average number of trees within JEN's vegetation Maintenance Spans which includes only trees that require active vegetation management to meet its vegetation management obligations. This EXCLUDES trees that only require inspections and no other vegetation management activities...". JEN indicated that the survey undertaken may have included trees that require inspection only. This is inconsistent with the definition and therefore DOEF0209 and DOEF0210 are considered non-compliant with the RIN.

Final review findings:

1. All initial review findings were addressed in the revised documents.
2. We did not find reason to believe that the data in table 8.2 has not been presented fairly in all material respects.
3. We did not find reason to believe that the Basis of Preparation for table 8.2 has not been presented fairly in all material respects.

Table 8.3 Service Area Factors

Variable Code	Table 8.3 Service area factors	Unit
DOEF0301	Route Line length	km

Key RIN requirements for this table:

1. The Route Line Length shall be calculated based on the distance between line segments not including sag or vertical components.
2. The Route Line Length does not necessarily equate to circuit length as the circuit length may include multiple circuits.

Initial review findings:

1. No issues were found.

Final review findings:

1. We did not find reason to believe that the data in the RIN table 8.3 has not been presented fairly in all material respects.
2. We did not find reason to believe that the Basis of Preparation for table 8.2 has not been presented fairly in all material respects.

Table 8.4 Weather Stations

Variable Code	Table 8.4 Weather stations	Post code	Suburb	Materiality
DOEF04001 to DOEF04032				

Key RIN requirements for this table:

1. The AER requires information for all weather stations in the service area in accordance with the variables provided in Table 8.4.
2. Where JEN considers that weather data from a weather station is not relevant to the management of its network a no must be recorded in the materiality column and further evidence provided in the Basis of Preparation document as to why the weather station is not relevant.

Initial review findings:

1. JEN considers that a station is not operational if it hasn't recorded data since January 2013. This assumption appears reasonable and should be included in the BoP.

Final review findings:

1. All initial review findings were addressed in the revised documents.
2. We did not find reason to believe that the data in the RIN table 8.4 has not been presented fairly in all material respects.
3. We did not find reason to believe that the Basis of Preparation for table 8.4 has not been presented fairly in all material respects.

Appendix A

Interviewees

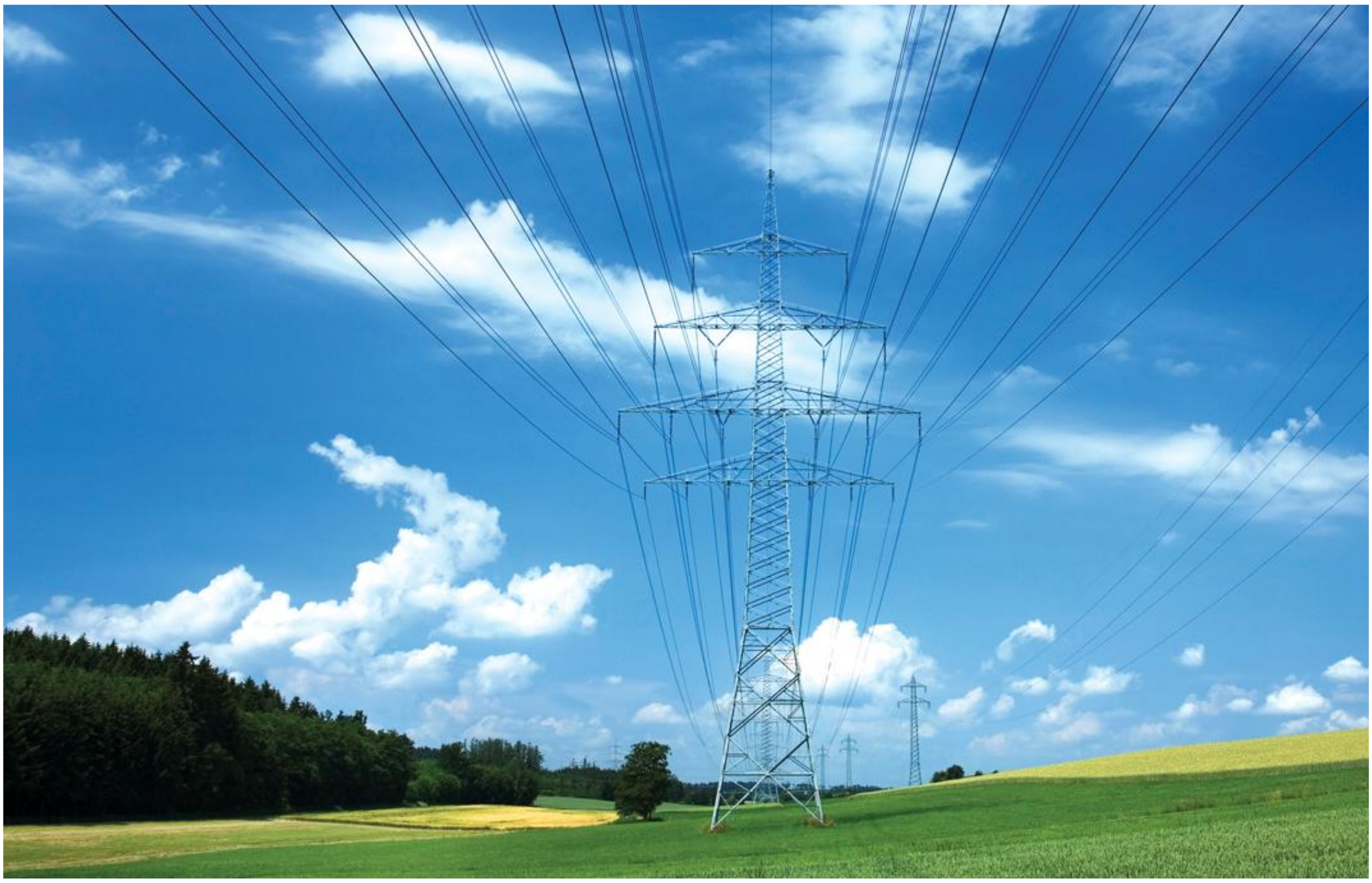

Table A–1: JEN's interviewees

Date	Name	Title	RIN Template
26 Feb 2014	Graeme Wirges	Manager Primary plant & Distribution Systems	Table 4.4
26 Feb 2014	Fatimah Husan	Asset Performance Engineer	Table 4.4
26 Feb 2014	Jonathan Chan	Senior Analyst – Regulatory Analysis & Strategy	Table 4.4
26 Feb 2014	Catherine Lee	Senior Asset Performance Engineer	Table 5.2, 6.1, 6.2, 6.3, 7.1,7.2,
26 Feb 2014	David Speirs	Network Performance Manager	Table 5.2, 6.1, 6.3
26 Feb 2014	Ashley Loyd	Network Capacity and Development Manager	Table 5.1, 5.3, 6.1, 6.2, 7.3, 7.4, 8.1
26 Feb 2014	Manoj Ghimire	Network Planning Engineer	Table 5.1, 5.3, 6.1, 6.2, 7.3, 7.4, 8.1
27 Feb 2014	Yvonne Spiteri	Electricity Revenue Manager	Table 5.2
27 Feb 2014	Tom Ruzeu	Senior Asset Performance & Bushfire Mitigation Engineer	Table 8.2, 8.3, 8.4

Jemena Electricity Networks (Vic) Ltd

Response to the economic benchmarking Regulatory Information Notice for the 2006-13 regulatory years

Annexure 6

Statutory declaration

Public

30 April 2014

Jemena
Vital Service. Vital Planet.

State of Victoria

STATUTORY DECLARATION

I, Paul John Adams of 321 Ferntree Gully Road, Mt Waverley 3149 in the State of Victoria, do solemnly and sincerely declare that:

1. I am an officer, for the purposes of the *National Electricity (Victoria) Law* (**NEL**), of Jemena Electricity Networks (Vic) Limited (ABN 82 064 651 083) (**JEN**), a regulated network service provider for the purposes of section 28D of the NEL. I am authorised by JEN to make this statutory declaration as part of the response of JEN to the Regulatory Information Notice dated 28 November 2013 (**Notice**) served on JEN by the Australian Energy Regulator (**AER**).

2. Having had regard to the Notice, I say that the actual information provided in JEN's response to the Notice is, to the best of my information, knowledge and belief:

   a) in accordance with the requirements of the Notice;

   b) in the case of actual information, is true and an accurate reflection of JEN's internal records used in the normal course of business.

3. Where it is not possible to provide actual information to comply with the Notice, JEN has, to the best of my information, knowledge and belief, for the purposes of complying with the Notice:

   a) provided JEN's best estimate of the information in accordance with the requirements of the Notice; and

   b) provided the basis for each estimate, including assumptions made and reasons why the estimate is the best estimate, given the information sought in the Notice.

I acknowledge that this declaration is true and correct, and I make it with the understanding and belief that a person who makes a false declaration is liable to the penalties of perjury.

Declared at MELBOURNE in the State of Victoria

this 28TH day of APRIL 2014

Signature of person making declaration

Before me: ALEXANDER JOHN MARRIOT-SMITH

Signature of authorised witness 321 Ferntree Gully Road, Mt. Waverley, VIC 3149

An Australian Legal Practitioner

(within the meaning of the *Legal Profession Act* 2004)

The authorised witness must print or stamp his or her name, address and title under section 107A of the *Evidence (Miscellaneous Provisions) Act 1958* (as if 1 January 2010), (previously Evidence Act 1958), (eg. Justice of the Peace, Pharmacist, Police Officer, Court Registrar, Bank Manager, Medical Practitioner, Dentist)