30 April 2014

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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

Confidential

Dear Chris

Jemena Electricity Networks (Vic) Ltd: 2013 Regulatory Information Notice

Jemena Electricity Networks (Vic) Ltd (**JEN**) is pleased to submit its response to the annual Regulatory Information Notice (**RIN**) that the Australian Energy Regulator (**AER**) served on JEN on 4 June 2012.

JEN's response includes the:

- Managing Director's statutory declaration
- extract of JEN board minutes
- audit reports relating to the financial and operational performance of JEN
- RIN schedule 1, and
- RIN excel templates.

Under the AER's instruction[1], JEN has provided a null response to the following Excel templates in its response to the annual RIN for the 2013 regulatory year:

(a) balance sheet
(b) cash flows
(c) changes in equity
(d) fixed assets
(e) depreciation
(f) written down values
(g) opex step changes
(h) cost of debt
(i) demand; and
(j) asset installations.

JEN provides two copies of its response to the annual RIN for the 2013 regulatory year: a confidential version with identified areas of content that is commercial-in-confidence, and a second public version with that content redacted.

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

[1] Email from Scott Haig (AER) to Robert McMillan (JEN), '*Jemena Annual Reporting RIN 2014-15*', 18 December 2013.

confidentiality claims for the 2013 regulatory year are consistent with confidentiality claims for the 2012 regulatory year.

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
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Copies:

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Attachment 1 – Claims for commercial-in-confidence

Attachment 1 - Jemena Electricity Networks (Vic) Ltd CY2012 RIN
Claims for commercial-in-confidence

The following table sets out specific sections of JEN's 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**	**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**
Schedule 1	Page 19 – 23, Table 3-1 Shared cost allocation. The expenditure quantum and allocators of shared costs.	The quantum of expenditure and associated allocators can be used to calculate the apportionment of overheads to different service groups. Expenditure overheads allocated to service groups are commercially confidential as they could jeopardise JEN's commercial position in future negotiations with prospective service providers.	Yes	Yes
Schedule 1	Page 25, paragraph 72 and 73.	The details relating to JEN's related party outsourcing arrangements (including structure and activity scope) are commercially confidential to JEN and could harm JEN's and its related parties' legitimate business interests if published. Public disclosure of this information may prejudice future tender processes between JEN and its service providers, as well as commercial negotiations between JEN's related parties and their unrelated customers.	Yes	Yes

Document containing confidential information	Page and paragraph number of the document which contains confidential information	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
Schedule 1	Page 26, Table 4-1 Related party transactions	The values of JEN's related party outsourcing transactions are commercially confidential to JEN and could harm JEN's and its related parties' legitimate business interests if published. Public disclosure of this information may prejudice future tender processes between JEN and its service providers, as well as commercial negotiations between JEN's related parties and their unrelated customers.	Yes	Yes
Schedule 1	Page 26-27, paragraphs 79-82 and Table 4-2 Actual cost determination	The details relating to JEN's related party outsourcing transactions are commercially confidential to JEN and could harm JEN's and its related parties' legitimate business interests if published. Public disclosure of this information may prejudice future tender processes between JEN and its service providers, as well as commercial negotiations between JEN's related parties and their unrelated customers.	Yes	Yes
Schedule 1	Pages 29-30, Table 4-5 Allocating related party costs. The allocator and basis.	The allocator and basis by which JEN allocates related party costs are commercially confidential to JEN and could harm JEN's legitimate business interests if published. Public disclosure of this information may prejudice future tender processes between JEN and its service providers.	Yes	Yes
Schedule 1	Page 42, Table 8-4 Actual unit costs Vs forecast unit costs	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 43, Table 8-5: Planned non-preferred service replacements	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes

Document containing confidential information	Page and paragraph number of the document which contains confidential information	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
Schedule 1	Page 43, paragraph 162 and 163 'unit cost variances'	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 44, Table 8-6 Planned replacement of non-preferred service due to height	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 44, paragraph 168 'Unit cost variance'	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 45, Table 8-7: Public lighting switch wire removal	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 45, Table 8-8: Replacement existing SWER lines with 22kV overhead bare conductor	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 46, Table 8-9: Replacing crossarms – based on age and condition	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 47, Table 8-10: Replacing poles - based on age and condition	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes

Document containing confidential information	Page and paragraph number of the document which contains confidential information	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
Schedule 1	Page 48, Table 8-11: Stake poles - based on age and condition	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 49, Table 8-12: Replacing undersized poles	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 49, Table 8-13: Stake undersized poles	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 50, Table 8-14: Replacing overhead conductor – mainly steel	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 50, Table 8-15: Service line clearance – overhead services requiring relocation	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 51, Table 8-16: Service line clearance – overhead services requiring undergrounding	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Table 52, Table 8-17: Vibration dampers and armour rods	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published.	Yes	Yes
Schedule 1	Page 53, Table 8-19: Zone substation earth grid replacements	The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests if published.	Yes	Yes

Document containing confidential information	Page and paragraph number of the document which contains confidential information	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
Appendix 1-1 JEN CY2013 RAS	Excel template 20. Demand and revenue. Cells within Table 1 and Table 2	Tables 1 and 2: where the customer number associated with a given tariff is less than 5, the data is classified as c-i-c in order to prevent the individual customer's details being identified. These instances relate to large customers, with supply to those customers being potentially subject to competition from other providers. Disclosing exact revenues received from those customers would provide an unfair advantage to JEN's potential competitors. Also, disclosing these customers' confidential usage data to the market could prejudice their energy purchase arrangements.	Yes	Yes
Appendix 1-1 JEN CY2013 RAS	Excel template 26. Related party. Cells within Table 1 and JEN's explanatory notes.	Table 1 (and JEN's explanatory notes) includes details relating to JEN's related party outsourcing transactions. These details are commercially confidential to JEN and could harm JEN's and its related parties' legitimate business interests if published. Public disclosure of this information may prejudice future tender processes between JEN and its service providers, as well as commercial negotiations between JEN's related parties and their unrelated customers.	Yes	Yes
Appendix 1-1 JEN CY2013 RAS	Excel template 27. Safety and bushfire. Cells within Table 8 and Table 9	Unit rate information (both AER determination and actual) is confidential to JEN because public disclosure could jeopardise JEN's commercial position in future negotiations with prospective service providers. This applies to all unit rate data.	Yes	Yes

Document containing confidential information	Page and paragraph number of the document which contains confidential information	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
Appendix 1-1 JEN CY2013 RAS	Excel template 30. Actual t-2 distribution tariff revenue.	Where the customer number associated with a given tariff is less than 5, the data is classified as c-i-c in order to prevent the individual customer's details being identified. These instances relate to large customers, with supply to those customers being potentially subject to competition from other providers. Disclosing exact revenues received from those customers would provide an unfair advantage to JEN's potential competitors. Also, disclosing these customers' confidential usage data to the market could prejudice their energy purchase arrangements.	Yes	Yes
Appendix 1-1 JEN CY2013 RAS	Excel template 31. Actual t-2 transmission tariff revenue.	Where the customer number associated with a given tariff is less than 5, the data is classified as c-i-c in order to prevent the individual customer's details being identified. These instances relate to large customers, with supply to those customers being potentially subject to competition from other providers. Disclosing exact revenues received from those customers would provide an unfair advantage to JEN's potential competitors. Also, disclosing these customers' confidential usage data to the market could prejudice their energy purchase arrangements.	Yes	Yes
Appendix 1-1 JEN CY2013 RAS	Excel template 32. TUoS Cost audit t-2	JEN's payments to embedded generators have been commercially negotiated and are commercial-in-confidence. Their publication could jeopardise future negotiated embedded generation network support outcomes.	Yes	Yes

Document containing confidential information	Page and paragraph number of the document which contains confidential information	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
Appendix 1-1 JEN CY2013 RAS	Excel template 33. Actual t-2 jurisdictional scheme tariff revenue	Where the customer number associated with a given tariff is less than 5, the data is classified as c-i-c in order to prevent the individual customer's details being identified. These instances relate to large customers, with supply to those customers being potentially subject to competition from other providers. Disclosing exact revenues received from those customers would provide an unfair advantage to JEN's potential competitors. Also, disclosing these customers' confidential usage data to the market could prejudice their energy purchase arrangements.	Yes	Yes
Appendix 1-5 Jemena capitalisation policy	The entire document	JEN maintains that its internal capitalisation policy is [c-i-c] because if businesses have the detail of each other's capitalisation policies they can tailor their own policies to influence benchmarking outcomes in their own favour, which in turn could have a flow on effect on prices.	No. The entire document is commercially confidential	No. The entire document is commercially confidential

Document containing confidential information	Page and paragraph number of the document which contains confidential information	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
Appendix 1-7: Special purpose financial report	The entire document	JEN's Special purpose financial report 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. As KPMG explained in a recent letter to the AER[2], such a situation could also create liability for KPMG.	No. The entire document is commercially confidential	No. The entire document is commercially confidential

[2] Attachment 2 (Letter from James P McClelland of KPMG) to email from Anton Murashev (JEN) to Kaye Johnston (AER), '*Jemena 2011 and 2012 Annual Reporting RIN response*', 14 April 2014

Jemena Electricity Networks (Vic) Ltd

Response to the annual Regulatory Information Notice for the 2013 regulatory year

Public

30 April 2014

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JEN's response to the annual Regulatory Information Notice for the 2013 regulatory year, 30 April 2014

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GLOSSARY

ABS	Australian Bureau of Statistics
ACS	Alternate Control Services
ACT	Australian Competition Tribunal
AER	Australian Energy Regulator
AMA	Asset Management Agreement
AMI	Advanced Metering Infrastructure
CAM	Cost Allocation Method
capex	Capital expenditure
Clearance Regulations	Electricity Safety (Electric Line Clearance) Regulations 2010
CPI	Consumer Price Index
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Providers
EDPR	Electricity Distribution Price Review
EMS	Emergency Management System
ES&L	Environmental, Safety and Legal Obligations
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
FTE	Full Time Equivalent
FY	Financial Year
GFN	Ground Fault Neutraliser
GSL	Guaranteed Service Levels
HV	High Voltage
JAM	Jemena Asset Management Pty Ltd
JEM	Jemena Ltd
JEN	Jemena Electricity Networks (VIC) Ltd
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MED	Major Event Day
NEL	National Electricity (Victoria) Law
NER	National Electricity Rules
O&M	Operating and Maintenance Costs
opex	Operating expenditure
RAS	Regulatory Accounting Statements

RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test for Distribution
RQM	Reliability and Quality Maintained
Safety Regulations	Electricity Safety (Network Assets) Regulations 1999
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SP AusNet	SP Australia Networks (Distribution) Ltd
SPI	Singapore Power International
SPIAA	SPI (Australia) Assets Pty Ltd
ST	Subtransmission
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
TNSP	Transmission Network Service Providers
UED	United Energy Distribution
Zinfra Contracting	Zinfra Contracting Pty Ltd
ZNX2	Zinfra Contracting Services

1. INTRODUCTION

1.1 SUBMISSION PURPOSE

1. This submission is the Jemena Electricity Networks (Vic) Ltd (**JEN**) response to the Regulatory Information Notice (**RIN**) that the Australian Energy Regulator (**AER**) issued to JEN on 4 June 2012 under Division 4 of Part 3 of the National Electricity (Victoria) Law (**NEL**). This response covers the regulatory year 2013 ending on 31 December 2013.

2. The RIN requires JEN to provide and prepare certain information for the AER to use for performance or exercise of its functions or powers conferred on it under the NEL or the National Electricity Rules (**NER**), namely for the purposes of:

- monitoring JEN's compliance with the AER's Final Jemena Electricity Networks (Victoria) Ltd Distribution determination 2011–2015 (the **2011-2015 Distribution Determination**)
- publishing reports on JEN's financial or operating performance, and
- preparing for the 2016-20 distribution determination.

3. This RIN response:

- provides the information required in the regulatory accounting statement templates provided by the AER and included as Appendix 1-1
- provides operational performance information required in the non-financial templates provided by the AER and included as Appendix 1-2
- sets out qualitative and quantitative explanations required by Schedule 1 to the RIN, and
- explains reasons for why any specific requested information cannot be provided in accordance with Schedule 1 of the RIN.

1.2 SUBMISSION STRUCTURE

4. JEN has structured this submission in accordance with each of the regulatory RIN templates as well as the information requested in section 1.1 of Schedule 1 of the RIN. The remainder of this Schedule 1 response is structured as follows:

- Section 1 – General
- Section 2 – Cost allocation
- Section 3 – Related party transactions
- Section 4 – Efficiency benefit sharing scheme
- Section 5 – Demand management incentive allowance
- Section 6 – Advanced metering infrastructure
- Section 7 – Safety and bushfire related expenditure
- Section 8 – Non-financial performance monitoring information

- Section 9 – Charts
- Section 10 – Audit reports
- Section 11 – Board resolution
- Section 12 – Statutory declaration
- Appendices

1.3 SUBMISSION VALUES AND TERMINOLOGY

5. This submission employs the following standards:

- Unless otherwise indicated, all numbers are expressed in nominal AUD$2013
- Unless otherwise indicated, JEN has adopted actual inflation using the Australian Bureau of Statistics (**ABS**) Consumer Price Index (**CPI**) group - Weighted Average of Eight Capital Cities[1]
- The Relevant Regulatory Year is the 2013 calendar year (**CY**) ending on 31 December 2013 and the third year of the 2011-2015 Distribution Determination
- The Financial Year (**FY**) is the 2012-13 Jemena Group financial year ending on 31 March 2013 (unless otherwise stated). JEN notes that the Regulatory Year 2013 spans two Jemena Group FYs: three months of FY2012-13 and nine months of FY2013-14
- Jemena Group means SPI (Australia) Assets Pty Ltd (**SPIAA**) and all of its wholly owned subsidiaries, and
- Unless otherwise expressly defined in this response, capitalised terms have the meanings defined in the RIN.

[1] JEN uses a one year September on September lag to compute actual inflation.

2. GENERAL

6. In this section, JEN responds to section 1 of Schedule 1 to the RIN for Relevant Regulatory Year 2013.

2.1 INFORMATION REQUIREMENTS

2.1.1 AER INFORMATION TEMPLATES

7. Sections 1.1(a) and 1.1(b) of Schedule 1 to the RIN require JEN to provide the following:

- the Regulatory Accounting Statements, being financial information as specified in the AER's Microsoft Excel workbook (named Appendix B), and
- non-financial information as specified in the AER's Microsoft Excel workbook (named Appendix C).

8. The AER information templates required are attached to JEN's response as Appendices 1-1 and 1-2 respectively.

2.1.2 RECONCILIATIONS

9. Section 1.1(c) of Schedule 1 to the RIN requires JEN to provide a Microsoft Excel workbook that reconciles and explains all movements between Statutory Accounts and the Regulatory Accounting Statements (**RAS**).

10. As JEN advised in its response to the draft RIN[2], JEN is not able to provide a complete set of all such reconciliations. JEN arrives at the RAS numbers by making required adjustments to its Statutory Accounts. Those adjustments are not entered into the System Analysis and Program (**SAP**) development system.

11. JEN has provided reconciliations for profit & loss, capital expenditure (**capex**) and operating expenses (**opex**) tables.

12. The reconciliations are provided as Appendix 1-3 in JEN's response.

2.1.3 ACCOUNTING AND CAPITALISATION POLICIES

13. Section 1.1(d)(i) of Schedule 1 to the RIN requires JEN to provide its Regulatory Accounting Principles and Policies and Capitalisation Policy for the current regulatory year.

14. The Regulatory Accounting Principles and Policies and Capitalisation Policy for 2013 are set out in Appendix 1-4 and 1-5.

15. Section 1.1(d)(ii) of Schedule 1 to the RIN also requires JEN to supply its Regulatory Accounting Principles and Polices and Capitalisation Policy for the previous regulatory year which JEN has submitted in its response to the 2012 RIN[3].

16. The substance of JEN's Regulatory Accounting Principles and Policies and Capitalisation Policy has not changed from 2012 to 2013.

[2] JEN's response to the Draft RIN, 24 February 2012.

[3] JEN's 2012 RIN response, 30 April 2013

2.1.4 COST ALLOCATION METHOD

17. Section 1.1(e)(i) of Schedule 1 to the RIN requires JEN to provide a policy determining how it allocates its overheads in accordance with the Cost Allocation Method (**CAM**)[4].

18. A copy of JEN's approved CAM is provided as Appendix 1-6. JEN's CAM is the policy that JEN uses to allocate overheads to distribution services. No additional policy exists.

19. Section 1.1(e)(ii) of Schedule 1 to the RIN also requires JEN to supply its cost allocation policy for the previous regulatory year. JEN's CAM has not changed from 2012 to 2013; therefore JEN has provided only its current (and only) approved CAM as Appendix 1-6.

2.2 CHANGES IN REGULATORY ACCOUNTING POLICIES

20. Section 1.2 of Schedule 1 to the RIN requires JEN to identify all changes between the Regulatory Accounting Principles and Policies provided in the response to paragraph 1.1(d).

21. JEN advises that the substance of JEN's Regulatory Accounting Principles and Policies and Capitalisation Policy has not changed, as stipulated in section 1.1(d) of Schedule 1 to the RIN.

2.3 REASONS AND QUANTUM OF CHANGES

22. Section 1.3(a) of Schedule 1 to the RIN requires JEN to explain the nature of and the reason for the change and Section 1.3(b) requires JEN to quantify the effect of changes identified.

23. As stated in Section 2.2 of this response, there is no change to the substance of JEN's Regulatory Accounting Principles and Policies and Capitalisation Policy. Hence, section 1.3 of Schedule 1 to the RIN is not applicable.

2.4 VARIANCE ANALYSIS

24. Section 1.4(a) to 1.4(d) of Schedule 1 to the RIN requires JEN to identify each material difference between amounts reported in the RAS and amounts allowed in the AER's 2011-2015 Distribution Determination for standard control services.

2.4.1 DISTRIBUTION REVENUE

25. Table 1-1 compares forecast distribution revenue (as determined in the AER's 2011-2015 Distribution Determination) and actual distribution revenue.

Table 1-1: Distribution revenue variance

Actual ($000)	Forecast ($000)	Variance ($000)	Variance (%)
226,279	210,148	+16,132	+8%

4 JEN's CAM – final decision, 26 February 2010

2.4.2 OPERATING EXPENDITURE

26. Table 1-2 compares forecast opex (as determined in the AER's 2011-2015 Distribution Determination) and actual opex (standard control services). Actual costs are inclusive of the related party payments. This variance is explained in section 2.5.1.

Table 1-2: Opex variance

Actual ($000)	Forecast ($000)	Variance ($000)	Variance (%)
72,620	62,230	+10,390	+17%

2.4.3 CAPITAL EXPENDITURE

27. Table 1-3 compares forecast capex net of customer contributions (as determined by the AER's 2011-2015 Distribution Determination) and actual net capex. This variance is explained in section 2.5.2.

Table 1-3: Capex variance

Actual ($000)	Forecast ($000)	Variance ($000)	Variance (%)
116,630	96,227	+20,403	+21%

2.4.4 DEMAND ENERGY

28. Table 1-4 compares forecast demand (as determined in the AER's 2011-2015 Distribution Determination) and actual demand.

Table 1-4: Demand energy variance

Actual Demand (GWh)	Forecast (GWh)	Variance (GWh)	Variance (%)
4,254	4,271	-17	0%

2.5 REASONS FOR VARIANCES

29. Section 1.5 of Schedule 1 to the RIN requires JEN to explain the reasons for any underlying operational activities or drivers that caused each material difference (where the difference is equal to or greater than 10 per cent) identified in the response to paragraph 1.4.

As the variances for distribution revenue (+8%) and energy demand (0%) are less than 10%, JEN has only provided an explanation for the opex (+17%) and capex variance (+21%).

2.5.1 OPERATING EXPENDITURE

30. JEN's opex and maintenance cost, allowing for step change allowances and the result of the Australian Competition Tribunal's (**ACT**) decision is higher than the forecast by 17%.

31. There are a number of drivers for this variance, with additional cost arising due to factors that could not be foreseen during the electricity distribution price review (**EDPR**) process. Some of the contributors to the higher spend are explained below.

Maintenance costs relating to safety obligations and regulatory compliance

32. New compliance obligations imposed on JEN—in addition to the recommendations arising from the Royal Commission into the 2009 bushfires—by Energy Safe Victoria (**ESV**). JEN experienced higher maintenance cost related to vegetation control and zone substation maintenance in the order of $1.7M compared to the allowance implicit in JEN's base year (CY2009). The increase is due to changes in ESV regulatory guidelines for vegetation control and timing of when the work commenced. Given the timing of when the ESV provided detailed information on the changes, it was impossible for JEN to cost the impact in time for the EDPR submission. The obligation changes included:

- F-factor monitoring and ESV auditing and investigations
- Adoption of Australian Standard 4373 requirements for tree pruning to retain amenity
- ESV outage reporting (ESV require monthly reporting by council area from Jan 2013), and
- Providing ESV consolidated vegetation clearance reports (from Sep 2013).

33. JEN's maintenance costs were $1.2M greater than the allowance implicit in JEN's base year. These are attributable to an increase in safety obligations and regulatory compliance tasks, including: asset incident investigations, extensive bushfire mitigation plans, increased customer engagement, representations in technical committees and improvement in work practices by introducing operational improvement teams. JEN's maintenance costs also increased due to additional network planning resources to comply with new technical regulatory obligations commencing from 1 January 2013 including:

- Distribution annual planning reviews and reporting
- Demand side engagement obligations
- Joint planning agreements between Transmission Network Service Providers (**TNSP**) and Distribution Network Service Providers (**DNSP**), and the
- Regulatory investment test for distribution (**RIT-D**).

Faults and emergency response costs

34. JEN reviewed its Emergency Management System (**EMS**) and response in 2010, which reduced JEN's emergency response time in the field and improved the coordination centre. These improvements led to higher costs in fault and emergency response of $1.3M compared to the allowance implicit in JEN's base year.

35. A number of major network events in 2013 also contributed to higher costs in faults and emergency response:

- Two separate pole fire events on 27 January and 19 February, and
- Two significant wind storm events on 12 August and 1 October.

Regulatory costs

36. JEN's regulatory costs have increased due to a substantial increase in regulatory activity by policy makers, rule makers and regulators, as well as more onerous regulatory requirements, including the requirement to submit this and other RIN responses. These costs have contributed an additional $0.8M.

Costs for which no allowance was made by the AER

37. In its final determination, the AER made no provision in JEN's operating expenditure forecast to pay the Singapore Power management fee. However, JEN was still required to make these payments in CY2013 up to May, which account for $0.6M for CY13

Loss of Jemena Group synergy benefits

38. As JEN noted in its November 2009 regulatory proposal for the 2011-15 regulatory control period, it previously benefited from synergies achieved during the 2006-10 period resulting from amalgamating JEN's former asset manager Agility with Alinta Asset Management[5], which eventually became JAM. The customers of this combined entity derived significant synergies from the large range of services it provided to United Energy Distribution (**UED**), JEN, and other clients.

39. A large part of these synergies arose from corporate support cost benefits that JEN realised through its asset manager's large client base. From 1 July 2011, the asset manager (JAM) lost a large share of its business with UED. A consequence of this is a loss of many of the benefits of the synergies to JEN and its customers from that date.

40. The loss of synergies is difficult to estimate in full. However, some of the readily quantifiable synergy losses account for a cost increase of approximately $4.7M in CY2013. JEN likely experienced other losses of synergies, which are not readily quantifiable.

2.5.2 CAPITAL EXPENDITURE VARIANCE

41. Table 1-5 compares JEN's actual net capex and the forecast amounts as determined in the 2011-15 Distribution Determination.

Table 1-5: Breakdown of capex variance

$m (nominal)	Forecast	Actual	Variance	%
Reinforcements	24.91	15.91	-9.00	-36%
New customer connections (net of customer contribution)	22.52	28.27	+5.75	+26%
Reliability and quality maintained	10.48	31.35	+20.87	+199%
Environmental, safety and legal obligations (ES&L)	16.58	18.33	+1.75	+11%
SCADA and network control	1.19	0.91	-0.28	-23%
Non-network general – IT	16.55	9.26	-7.29	-44%
Non-network general – others	3.99	12.58	+8.59	+215%
Total	96.22	116.61	+20.39	**+21%**

42. JEN's actual capex was $20.39M higher than the allowance in the 2011-15 Distribution Determination. The major variances that contribute to the $20.39M are set out below.

5 JEN, Regulatory Proposal 2011-15, 30 November 2009, p.57

Reinforcement (-$9M variance)

43. Five projects set out below account for the lower than forecast capex for this category. These projects were either completed earlier in the regulatory control period, or rescheduled for later years

- *Preston 6.6kV to 22kV Conversion*—JEN has rescheduled the 2013 component of the voltage conversion project in the Preston area to 2014. JEN has completed, as planned, significant conversion work in prior years. In 2013 the scoping and design for the 2014 component of the conversion project was completed. The under spend on this project was $2.2M.
- *The Pascoe Vale Transformer Upgrade* project was originally proposed by JEN as being required in 2011. However the AER's expenditure allowance assumed that the project would not be required until 2013. Nevertheless, JEN had to proceed with this major reinforcement project in 2012 to ensure security of supply was not compromised and network peak demand was met. As a result, little expenditure was incurred in 2013. The under spend on this project was $0.8M.
- *Broadmeadows South reinforcement*—JEN has rescheduled the reinforcement project in the Broadmeadows South area from 2013 to 2014. JEN commenced this project in 2013, however the expenditure is lower by $1.5M than forecast for 2013, in part due to the introduction of new design standards. This project will be completed in 2014.
- *Yarraville zone substation*—As a part of the final determination, $1M of works in the Yarraville area was allowed for in the Reinforcement category in 2013 to upgrade zone substations. Due to urban infill, JEN deemed it prudent to rebuild the existing Yarraville zone substation to maintain reliability in the area. As a result, the expenditure was incurred under the Reliability and Quality Maintained category, resulting in a $1M underspend in the reinforcement category of 2013.
- *Miscellaneous distribution feeder augmentation*—66kV line work and capacitor bank installations were deferred to 2015 and 2016 and, as a result, these projects create an under spend of $3.5M.

New customer connections (+$5.75M variance)

44. In 2013, JEN experienced higher levels of capex in dual and multiple occupancy, medium density housing and special capital works, due to higher activities and unit costs than were used in the forecast of the regulatory proposal.

45. Sections 6 and 7 of JEN's Electricity Distribution Licence (ESC October 2008) require JEN to offer connections in response to a request from a retailer, customer or embedded generator. This increase in customer connection capex is therefore beyond JEN's control, as JEN is obliged to incur the associated connection costs.

Reliability and Quality Maintained (**RQM**) (+$20.87M variance)

46. Three areas as set out below contributed to account for the higher than forecast capex for this category:

- *Zone substation equipment replacement*—The AER was of the opinion that zone substation equipment replacement could be deferred. However, JEN had to proceed with the schedule originally proposed to ensure that reliability and safety could be maintained, particularly in the Essendon (+$4.4M) and Yarraville (+$11.2M) supply areas. As part of the final determination, works in the Yarraville area were allowed for in the Reinforcement category. Due to urban infill, JEN deemed it prudent to rebuild the existing zone substation to ensure the reliability and safety in the area was maintained.

- *Distribution network asset equipment replacement and network performance projects*—The AER was of the opinion that lower than proposed volumes of distribution network asset replacement were required. In addition the AER rejected all proposed projects associated with network performance. Examples of where JEN had to proceed with replacing equipment in excess of the volumes allowed for by the AER include: surge diverters, non-tension connectors and unserviceable switchgear (+$3.8M). This was required to ensure that performance and safety could be maintained at various locations on the distribution network.

- *Underground cable replacement*—The AER was of the opinion that lower than proposed volumes of underground cable replacement were required. However JEN had to proceed with replacing unserviceable underground cables and joints (+$1.9M) to ensure that reliability was maintained at various locations on the distribution network.

Environmental, safety and legal obligations (**ES&L**) (+$1.75M variance)

47. Three projects, as set out below, contributed to the higher than forecast capex for this category.

- *Pole top replacement*—JEN is on track to deliver the AER's approved volume in the 5-year period. In 2013, JEN continued to inspect assets in accordance with the Asset Inspection Manual and replace crossarms based on condition. Crossarms could also be replaced based on other drivers such as reinforcement the cost of which was captured against other project activities. The expenditure was forecast by the AER to be incurred evenly across this EDPR period, however JEN incurred a lower than forecast expenditure in 2013 (-$3.0M)

- *Replacing existing single wire earth return (**SWER**) lines with 22 kV Overhead Bare Conductor*—JEN has completed the replacement of SWER as planned in 2013. The entire volume of SWER was replaced as one consolidated project (+$1.6M), whereas the expenditure was forecast by the AER to be incurred evenly across this EDPR period across this EDPR period

- *Non-preferred service replacement*—JEN is on track to deliver the AER's approved volume in the 5-year period. In 2013, JEN continued to replace non-preferred services with priority being given to a similar, but distinct type of replacement—“Planned replacement of non-preferred services due to height”. The actual unit cost is higher than forecast, therefore resulting in a higher than forecast expenditure for this project (+$3.0M).

Non-network general – IT (-$7.29M variance)

48. Two projects below contributed to the lower than forecast capex for this category:

- Enterprise corporate system upgrades, including SAP, were delivered earlier than planned, resulting in an under spend of $5.3M in 2013. This is a timing issue, which is linked to the over spend on those systems in 2012.

- The new distribution management system scheduled for 2012 and 2013 has not proceeded as planned, resulting in an under spend of $1.4M. The new systems solution was to be shared with the existing UED distribution management system. JEN and UED are no longer partners sharing systems and this has resulted in the intended distribution management system being unviable and uneconomic. Jemena is working on a new distribution management system strategy, which is unlikely to be implemented before 2016.

Non-network general – Others (+$8.59M variance)

49. The cost of JEN’s northern depot re-development project is the reason for the higher than forecast capex in this category (+$8.59M). The design and layout stage was completed in 2012 and construction commenced in 2013. The expenditure on the northern depot project was therefore higher than forecast, as a result of deferring the delivery of the project to 2013. The allowance assumed the project would be completed by the end of 2012.

2.6 CHANGES IN OVERHEAD ALLOCATION POLICY

50. Section 1.6 of Schedule 1 to the RIN requires JEN to identify all changes in its policy in allocating overheads (provided in response to Section 1.1(e) of Schedule 1 to the RIN).

51. There was no change to JEN's policy in allocating overheads.

2.7 REASONS AND QUANTUM OF CHANGES (OVERHEADS ALLOCATION POLICY)

52. Section 1.7(a) of Schedule 1 to the RIN requires JEN to explain the nature of and the reason for the changes and Section 1.7(b) requires JEN to quantify the effect of changes identified.

53. As stated in Section 2.6 of this response, there is no change to JEN's overheads allocation policy.

3. COST ALLOCATION

54. In this section, JEN responds to section 2 of Schedule 1 to the RIN for the 2013 Relevant Regulatory Year.

55. JEN has applied its approved CAM in all relevant circumstances. JEN's current CAM was approved by the AER in February 2010. A copy of this CAM is provided in Appendix 1-8.

3.1 DIRECTLY ATTRIBUTED AND ALLOCATED COSTS

56. Section 2.1 parts (a), (b) and (c) of Schedule 1 to the RIN requires JEN to identify each item in the RAS that is allocated to JEN:

- on a directly attributable basis
- on a causation basis, or
- not allocated on a directly attributable basis and cannot be allocated on a causation basis.

57. The items allocated to JEN have been identified and are listed in Table 3–1.

3.2 ALLOCATED COST AND ALLOCATORS

58. Section 2.2(a) and (c) of Schedule 1 to the RIN requires JEN to state, for each item identified in response to paragraph 2.1(b), the quantum of the item that has been allocated and the numeric quantum of the allocators used.

59. Table 3–1 sets out the quantum of these items and allocators. The causation basis of each cost item is shared, causal and operating in nature, in accordance with section 2.2(a)–(c) and 2.4(a) of Schedule 1 to the RIN.

Table 3–1: Shared cost allocation

Cost Item [Section 2.1(a)–(c)]	Quantum ($) [Section 2.2(a)]	Method of allocation and reason for Basis [Section 2.2(b)]	Allocator %
Office of the Chief Executive Officer (CEO) Executive oversight and board liaison on asset and financial management, stakeholder relations, and human resources. CEO costs include directors' travel expenses and fees, CEO compensation, consulting fees, and administration expenses.	[C-I-C [redacted]	Method: time writing and full time equivalent (**FTE**) survey. Reason: CEO costs support Jemena's corporate governance and asset management, which directly benefit JEN and other Jemena assets and clients. Costs were allocated to assets and clients using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client.	[redacted]
Office of the Chief Financial Officer (CFO) Executive oversight of financial reporting, management, and fund raising. Costs include CFO compensation, travel, consulting fees, and administration expenses. Also include significant unbudgeted costs or savings.	[redacted]	Method: time writing and FTE survey, and adjusted fair value. Reason: CFO costs support Jemena's corporate governance and financial management, which, like CEO costs, directly benefit JEN and other Jemena assets and clients. Costs were allocated to assets and clients using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client. Significant unbudget costs or savings are assumed to accrue to any asset or client based on its fair value within the Jemena Group. So, the adjusted fair value driver is used to allocate significant unbudgeted costs or savings to JEN (and other assets or clients).	[redacted]
Financial reporting Management of financial accounting (internal and external), accounts payable, accounts receivable and payroll. Costs include salaries, procurement of external advice, and training.	[redacted]	Method: time writing and FTE survey. Reason: Financial reporting costs support Jemena's financial management, which directly benefit JEN and other assets or clients. Costs were allocated to assets and clients using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client.	[redacted]

Cost Item [Section 2.1(a)–(c)]	Quantum ($) [Section 2.2(a)]	Method of allocation and reason for Basis [Section 2.2(b)]	Allocator %
Treasury and financing Management of Jemena's fund raising, debt and equity holder relations, and treasury functions. Costs include salaries, travel expenses for debt raising roadshows, credit rating fees, and training.	[redacted]	Method: time writing driver and FTE survey. Reason: Treasury and financing costs support Jemena's raising and management of debt and equity financing, which is essential to the management of JEN and other Jemena assets and clients. Treasury and financing costs were allocated to assets and clients using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client.	[redacted]
Financial planning and management reporting Management of financial reporting and planning functions, including budgeting, forecasting, asset valuation, and corporate cost allocation. Costs include salaries, procurement of external advice and training.	[redacted]	Method: time writing driver and FTE survey. Reason: Financial planning and management reporting costs support Jemena's long-term network planning and cost reduction initiatives, including development of JEN's asset management plan. Financial planning and management reporting costs were allocated to assets and clients using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client.	[redacted]
Legal Legal management of and advice on economic regulation, environmental law, employment law, property law, and company law, including the role of company secretary. Costs include salaries, court and tribunal costs, and engagement of external lawyers.	[redacted]	Method: time writing and FTE survey. Reason: Legal costs support Jemena's compliance with its legal obligations, including those of JEN. Legal costs were allocated using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client.	[redacted]

Cost Item [Section 2.1(a)–(c)]	Quantum ($) [Section 2.2(a)]	Method of allocation and reason for Basis [Section 2.2(b)]	Allocator %
Corporate affairs Management of corporate communications to stakeholders, including customers, employees, neighbours, and state and federal governments and regulators. Costs include salaries, travel expenses for external meetings, and printing costs for external communications.	[redacted]	Method: time writing and FTE survey. Reason: Corporate affairs costs support Jemena's communications with internal and external stakeholders, which are particularly important for JEN's customers and other external stakeholders. Corporate affairs costs were allocated using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client.	[redacted]
Health safety and environment (HSEQ) Management of employee HSE training, performance and quality. Costs include salaries, external advice and training services.	[redacted]	Method: time writing and FTE survey. Reason: HSEQ costs support Jemena's standards of health, safety and quality and minimise any adverse impact on the environment. HSEQ costs were allocated using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client.	[redacted]
Human resources Management of recruitment and remuneration benefit services. Costs include salaries, recruitment agent fees, and training.	[redacted]	Method: time writing and FTE survey. Reason: Human resources support Jemena's management of its human resources, including those that work directly on JEN-related projects. Human resources costs were allocated using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client.	[redacted]
Financial improvement Management of finance continuous improvements. Costs include salaries and employee costs, consultancy costs, and training.	[redacted]	Method: time writing and FTE survey. Reason: Financial improvement costs support Jemena's finance continuous improvement initiatives, which benefit each asset within the Jemena Group. Financial improvement costs were allocated using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the	[redacted]

Cost Item [Section 2.1(a)–(c)]	Quantum ($) [Section 2.2(a)]	Method of allocation and reason for Basis [Section 2.2(b)]	Allocator %
		time spent by staff on activities for each asset and client.	
Information services Provision and management of IT infrastructure and services. Costs include salaries, procurement of software and hardware, telecommunications, consulting costs, and system support costs.	[redacted]	Method: information systems (IS) driver. Reason: IS costs support the delivery of Jemena's capital and operating programs, including those of JEN. IS costs were allocated using casual drivers, including ownership and use of applications, number of service requests and number of PCs used as a share of total Jemena PCs. For example outsourced IT operations were allocated using ownership and use of applications, number of service requests and number of PCs used as a share of total Jemena PCs. Internally sourced IT strategy, infrastructure services and operations costs were allocated using the number of PCs used by each asset and client as a share of total Jemena PCs.	[redacted]
Regulatory Management of regulatory obligations, price reviews, consultations and relationships with governments, regulators and market operators. Costs include salaries, training, travel, and consultancy costs.	[redacted]	Method: time writing and FTE survey. Reason: Regulatory costs support management of Jemena's regulated and non-regulated assets, including JEN. Regulatory costs were allocated using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client.	[redacted]
Risk and insurance Procurement of insurance and management of risk, including for bushfire and other natural disasters. Costs include salaries and insurance premiums.	[redacted]	Method: insurance driver, which is based on declared values. Reason: Risk and insurance costs support the effective management of Jemena's risks, including those faced by JEN. Risk and insurance costs were allocated to assets using the declared (or insured) values, as the causal driver. These values are used to determine the insurance premiums and other related paid by Jemena on behalf of all its assets.	[redacted]

Cost Item [Section 2.1(a)–(c)]	Quantum ($) [Section 2.2(a)]	Method of allocation and reason for Basis [Section 2.2(b)]	Allocator %
Internal audit Management of internal audits. Costs include salaries and other employee costs.	[redacted]	Method: time writing and FTE survey. Reason: Internal audit costs support Jemena's corporate governance, which directly benefit JEN and other Jemena assets and clients. Internal audit costs were allocated using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client.	[redacted]
Business planning and improvement Management of business planning and continuous improvements, including business process and organisationalional design, process mapping and review costs. Costs include salaries and employee costs, consultancy costs, and training.	[redacted]	Method: time writing and FTE survey, and adjusted fair value. Reason: Business planning and improvement costs support Jemena's asset management and continuous improvement initiatives, which benefit each asset within the Jemena Group. Business planning costs were allocated using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client. Benefits from business improvement costs are assumed to accrue to assets and clients based on their fair value within the Jemena Group. So, the adjusted fair value driver is used to allocate these costs to JEN (and the other assets and clients).	[redacted]
Taxation Management of indirect and direct tax compliance and planning. Costs include salaries and other employee related expenses, and procurement of external advice.	[redacted]	Method: time writing and FTE survey. Reason: Taxation costs support Jemena's obligations under tax law, including those of JEN. Taxation costs were allocated using time writing data, supported by feedback from a recent FTE survey. Time writing reflects an accurate measure of the time spent by staff on activities for each asset and client.	[redacted]][6]

[6] The quantum of expenditure and associated allocators can be used to calculate the apportionment of overheads to different service groups. Expenditure overheads allocated to service groups are commercially confidential as they could jeopardise JEN's commercial position in future negotiations with prospective service providers.

3.2.1 SHARED COST ALLOCATION METHOD

60. Section 2.2(b) of Schedule 1 to the RIN requires JEN to explain the allocation method and reasons for choosing that method in relation to items identified in 2.1(b).

61. The allocation methods for each item and reasons for choosing the methods are listed in

62. **Table** 3–1: Shared cost allocation

63. It is clear that where costs can be allocated using the time writing driver they are allocated on this basis. In the case where costs cannot be allocated using this driver, costs are allocated to JEN on a specific driver or adjusted fair value driver. For example, Risk and Insurance cost centre costs are allocated based on an insurance driver (declared value).

64. For more details on the method used in allocating shared costs, refer to Template 17a (supporting work paper to Template 17) in Appendix B (Appendix 1-1 of JEN's response).

3.3 NON-CAUSAL ALLOCATION

65. Section 2.3 of Schedule 1 to the RIN requires JEN to state the quantum of each item identified in response to Section 2.1(c) and state whether it was material. The section also requires JEN to explain the allocation method and reasons for choosing that method and why it cannot be allocated on a causation basis.

66. This requirement is not applicable as JEN has not identified any item that is not allocated on a directly attributable basis and cannot be allocated on a causation basis.

3.4 OPERATING, MAINTENANCE AND FIXED ASSET COSTS ALLOCATION

67. Section 2.4 of Schedule 1 to the RIN requires JEN to state that each item has been identified and allocated according to the approved CAM.

68. Each operating, maintenance and fixed asset cost allocated to an activity area in part on a directly attributable basis or on a causation basis or both was allocated in a way that is consistent with JEN's approved CAM.

4. RELATED PARTY TRANSACTIONS

69. In this section, JEN responds to section 3 of Schedule 1 to the RIN for the 2013 Relevant Regulatory Year.

4.1 RELATED PARTIES

70. Section 3.1 of Schedule 1 to the RIN requires JEN to identify each of JEN's Related Parties. The Related Party entities JEN has a transaction with are:

- Jemena Asset Management (**JAM**) Pty Ltd
- Zinfra Contracting Services (**ZNX2**) Pty Ltd
- Jemena Ltd (**JEM**)
- SP Australia Networks (Distribution) Ltd (**SP AusNet**), and
- SPI Powernet Pty Ltd.

71. For the period 1 January 2012 to 1 April 2012 JEN procured core network operations and maintenance services by way of its Asset Management Agreement (**AMA**) with Jemena Asset Management Pty Ltd (**JAM**). This is the outsourcing arrangement described in the 2011 JEN RIN and set out in the AMA and Change Notice issued by JEN which were included in the 2011 JEN RIN submission.

[redacted] [[redacted]

[redacted]

[redacted]

- [redacted]][7]

4.2 RELATED PARTY TRANSACTIONS

74. Section 3.2 of Schedule 1 to the RIN requires JEN to identify each transaction for an amount greater than $500,000 relating to the provision of standard control services, Advanced Metering Infrastructure (**AMI**), ACS or negotiated distribution services between JEN and a Related Party.

75. The transactions JEN has with Related Parties are listed in **Table 4-1**.

7 The detail relating to JEN's related party outsourcing arrangements are commercially confidential to JEN and could harm JEN's legitimate business interests if published. Public disclosure of this information may prejudice future tender processes between JEN and its service providers.

Table 4-1: Related Party transactions

Name of Related Party	Services Provided	Capex $000	Opex $000
Jemena Ltd	Management Services	[redacted]	[redacted]
ZNX(2) Pty Ltd(formerly known as Jemena Asset Management 6 Pty Ltd)	Management Services	[redacted]	[redacted]
Jemena Asset Management Pty Ltd	Management Services	[redacted]	[redacted]

76. JEN has not included its transactions with SP AusNet and SP Powernet as the prices of these transactions are regulated (e.g. cross boundary charges and transmission charges).

4.3 INFORMATION ON RELATED PARTY TRANSACTIONS

4.3.1 NAME OF RELATED PARTY

77. Section 3.3(a) of Schedule 1 to the RIN requires JEN to state the name of the Related Party for each transaction identified in the response to Section 3.2 of Schedule 1 to the RIN. The names of the Related Parties are listed in **Table** 4-1.

4.3.2 COUNTER PARTY

78. Section 3.3(b) of Schedule 1 to the RIN also requires JEN to identify other counter parties involved in the transactions identified. JEN wishes to advise that there are no other counter parties involved in the transactions identified.

4.3.3 NATURE AND PURPOSE OF RELATED PARTY TRANSACTIONS

79. Section 3.3(c) of Schedule 1 to the RIN requires JEN to explain the nature and purpose of the transaction, including the good(s) or service(s) provided by the Related Party.

[c-i-c[9] [redacted]

[redacted]

[redacted]

81. [redacted]

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8 The values of JEN's related party outsourcing transactions are commercially confidential to JEN and could harm JEN's legitimate business interests if published.

9 The structure and activity scope of JEN's related party outsourcing arrangements are commercially confidential to JEN and could harm JEN's legitimate business interests if published.

[redacted]

[redacted]

[redacted]

4.3.4 ACTUAL COSTS

84. Section 3.3(d) of Schedule 1 to the RIN requires JEN to state the actual costs incurred by the Related Parties in providing good(s) or services, not including any profit margin or management fee incurred by JEN.

85. The amounts of actual costs incurred have been provided in Template 26 (Related Party Transactions) in Appendix B (Appendix 1-1 of JEN's response).

4.3.5 DETERMINING ACTUAL COSTS

86. Section 3.3(e) of Schedule 1 to the RIN requires JEN to explain how the actual costs of the good(s) or service(s) incurred was determined.

Capex

87. In delivering JEN's capex program, JEN's related parties incurred costs in relation to materials, labour (internal and external) and other resources. These costs are captured in the SAP Enterprise Resource Planning (**ERP**) system of the related parties involved, including overheads and margin (where a margin is applicable).

88. To determine the actual costs, margins have been removed where relevant from the related party charges to JEN. Where no margins were charged, JEN's costs are equal to the related party's costs.

Operating and Maintenance Costs (**O&M**)

89. The O&M costs incurred by JEN's related parties while delivering management services to JEN are captured in the ERP system of the related parties involved. Non-capital costs (direct costs and overheads) are recorded exclusive of margin in the ERP system. For more details on the cost capturing process, refer to JEN's AER-approved CAM in Appendix 1-8.

90. The actual O&M costs are determined as shown in **Table** 4-2.

Table 4-2: Actual Cost Determination

Related Party	Basis
[c-i-c[10] [redacted]	[redacted]
[redacted]	[redacted]]

[10] The basis of cost determination for JEN's related party transactions is commercially confidential to JEN and could harm JEN's legitimate business interests if published.

4.3.6 REGULATORY REPORTING

91. Section 3.3(f) of Schedule 1 to the RIN requires JEN to explain how the actual costs of the good(s) or service(s) incurred is (are) reflected in the Regulatory Accounting Statements (**RAS**).

92. Actual costs (not including any Related Party margin) have been reported in the RAS as set out in Table 3-3.

Table 4-3: Related party cost reporting in RAS

Templates in Appendix B (Appendix 1-1 of JEN's response)	Table	Categories
11a (maintenance, excluding margin)	1 and 2	All
12a (operating, excluding margin)	1	Operating Costs
6b (capex, excluding margin)	1 to 8	All
6d (capex overheads, excluding margin)	1 to 8	All
9 (addition by Tax)	1 and 2	Addition, excluding margin
26 (Related Party transactions)	1	All

4.3.7 ALLOCATING RELATED PARTY TRANSACTION COSTS

93. Section 3.3(g) of Schedule 1 to the RIN requires JEN to identify the Asset Category, Maintenance Cost category or Operating Cost category to which the actual cost(s) is allocated.

94. Lists of Asset Cost categories, Maintenance Cost categories and Operating Cost categories are set out in Table 3-4.

Table 4-4: Cost categories vs actual cost allocations

Operating Costs	Maintenance Costs	Addition to fixed assets
network operating	Routine	Reinforcement
billing & revenue collection	condition based	new customer connections
advertising/marketing	Emergency	RQM
customer service	SCADA/network control	environmental, safety & legal
Regulatory	Other	non network – IT
AMI	AMI	non network - other
public lighting	public lighting	AMI
ACS	ACS	public lighting
unregulated services		ACS
		negotiated services
		unregulated services

4.3.8 ALLOCATORS AND ALLOCATION BASIS

95. Section 3.3(h) of Schedule 1 to the RIN requires JEN to explain the basis upon which the actual costs of the good(s) or service(s) was or were allocated, as identified in the response to paragraph (g), and state the quantum of any allocator applied.

96. In accordance with the RIN, JEN reports the actual costs attributable to JEN for each Related Party transaction.

97. Where costs that can be directly attributable to an Asset Cost, Operating Cost or Maintenance Cost category (e.g. via general ledger account code or activity code), they are allocated in that category.

98. Where costs cannot be directly attributable, they are allocated to various categories in accordance with the shared cost allocation method, as set out in the CAM.

99. JEN is not able to provide the allocator by which related party transaction charges have been allocated, as JEN's allocators do not apply specifically to related party costs—rather related party costs are just one component of JEN's wider cost base, which is allocated using a range of allocators. However, JEN is able to provide an estimate of the proportion of related party transaction charges allocated to the Fixed Asset, Maintenance and Operating cost categories. Table 3-5 lists the proportion and the respective basis.

Table 4-5 Allocating Related Party Costs

Related Party	Cost categories	Allocator	Basis
Jemena Asset Management Pty Ltd	**Operating Costs**	[c-i-c [11]	
	Network operating	[redacted]	[redacted]
	Customer Service	[redacted]	[redacted]
	Other SCS	[redacted]	[redacted]
	ACS	[redacted]	[redacted]
	Maintenance Costs Routine Condition based Emergency SCADA/Network Control Other - Standard Control Services Public Lighting Alternative control -other	[redacted]	[redacted]
	Addition to Fixed Assets		
	Reinforcement	[redacted]	[redacted]
	New Customer Connections	[redacted]	[redacted]
	RQM	[redacted]	[redacted]
	Environmental/Safety/Legal	[redacted]	[redacted]
	Public Lighting	[redacted]	[redacted]
	Alternate Control Services Negotiated	[redacted] [redacted]	[redacted] [redacted]
ZNX(2) Pty Ltd (formerly known as Jemena Asset Management 6 Pty Ltd)	**Operating Costs**		

[11] The allocator basis and value of allocated related party costs are commercially confidential to JEN and could harm JEN's legitimate business interests if published.

Related Party	Cost categories	Allocator	Basis
	AMI	[redacted]	[redacted]
	Maintenance Costs AMI	[redacted]	[redacted]
	Addition to Fixed Assets		
	AMI ACS	[redacted] [redacted]	[redacted] [redacted]
Jemena Ltd	**Operating Costs**		
	Regulatory	[redacted]	[redacted]
	Others ACS and others **Maintenance Costs**	[redacted] [redacted] [redacted]	[redacted] [redacted] [redacted]
	Addition to Fixed Assets		
	SCADA/Network Control	[redacted]	[redacted]
	Non Network General – IT	[redacted]	[redacted]

5. EFFICIENCY BENEFIT SHARING SCHEME

100. In this section, JEN responds to section 4 of Schedule 1 to the RIN for the 2013 Relevant Regulatory Year.

5.1 CHANGES IN CAPITALISATION POLICY STATEMENT

101. Section 4.1 of Schedule 1 to the RIN requires JEN to identify all changes between the capitalisation policy statements provided in response to Section 1.1(d) of Schedule 1 to the RIN.

102. JEN advises that there was no change to its capitalisation policy for the Relevant Regulatory Year ending 31 December 2013. JEN has attached its current capitalisation policy at Appendix 1-5 of JEN's response.

5.2 IMPACT OF CHANGE

103. As stated in section 5.1 of JEN's response, there was no change to its capitalisation policy for 2013. Therefore, Section 4.2 of Schedule 1 to the RIN is not applicable.

6. DEMAND MANAGEMENT INNOVATION ALLOWANCE (**DMIA**)

104. In this section, JEN responds to section 5 of Schedule 1 to the RIN for the 2013 Relevant Regulatory Year.

6.1 IDENTIFYING DEMAND MANAGEMENT PROJECTS OR PROGRAMS

105. Section 5.1 of Schedule 1 to the RIN requires JEN to identify each demand management project or program which JEN seeks approval of.

106. JEN seeks approval for one project, being “Impact of the Energy Portal[12] on Customers' Consumption Habits”, for the 2013 Regulatory Year. Following on from the release of the Energy Portal to Jemena customers in June 2012, Jemena undertook an initiative in 2013 to understand the impact of the Energy Portal on customers' electricity consumption. JEN seeks approval for costs associated with engaging an analyst in the 2013 Regulatory Year to assess the capabilities of the Energy Portal as a demand management initiative and to promote the portal to JEN's customers.

6.2 DETAILED INFORMATION FOR DEMAND MANAGEMENT PROJECTS OR PROGRAMS

107. Section 5.2 of Schedule 1 to the RIN requires JEN to provide detailed information for each demand management project or program identified in response to section 5.1 of Schedule 1 to the RIN.

6.2.1 COMPLIANCE

108. Section 5.2(a)(i) of Schedule 1 to the RIN requires JEN to explain how JEN's initiative complies with the DMIA criteria set out in section 3.1.3 of the Demand Management Incentive Scheme (**DMIS**).

109. Expenditure associated with JEN's Energy Portal over two Regulatory Years 2011 and 2012, was approved by the AER on the basis that the Energy Portal meets the DMIA criteria as set out in section 3.1.3 of the DMIS. The capabilities of the Portal as a Demand Management initiative were yet to be assessed and confirmed. For this reason, JEN engaged an analyst in the 2013 Regulatory Year to assess the capabilities of the Portal as a Demand Management initiative. JEN considers that the engagement of an analyst in the 2013 Regulatory Year complies with DMIA criteria, set out in section 3.1.3 of the DMIS, in the following ways:

- Section 3.1.3-1 – The project has the potential to provide Demand Management capabilities through promoting portal use among JEN's customers and giving them the tools to manage their demand.
- Section 3.1.3-2 – The project is a broad based Demand Management initiative targeted at consumers with smart meters, and is not aimed at a specific location on the network.
- Section 3.1.3-3 – The project is an initiative designed to explore customers' response to smart metering information and price signals.
- Section 3.1.3-4 – The project is a non-tariff based project and the costs are not recovered under any other incentive scheme.

[12] or *'JEN Electricity Outlook'* as it is branded.

- Section 3.1.3-5 – The project cost has not been recovered under other schemes. See section 5.2.8 of JEN's response for more details.
- Section 3.1.3-6 – The nature of expenditure is operating expenditure.

6.2.2 NATURE AND SCOPE

110. Section 5.2(a)(ii) of Schedule 1 to the RIN requires JEN to explain the nature and scope of JEN's initiative.

111. The nature of the project is to develop a Demand Management initiative based on the already approved Energy Portal and AMI projects.

112. The scope of the project includes the development of questionnaires and strategies as the basis for carrying out surveys in order to understand what impact the Energy Portal has had on our customers, and assess the impact if there has been a change in customers' consumption.

6.2.3 AIMS AND EXPECTATIONS

113. Section 5.2(a)(iii) of Schedule 1 to the RIN requires JEN to explain the aims and expectations of JEN's initiative.

114. The aims and expectations of the project are to:

- better understand the behaviour of customers when presented with near real time information about their electricity usage via the Energy Portal
- demonstrate real benefits of the Energy Portal and the AMI technology to consumers, government, regulators and retailers
- develop a demand management initiative based on the Energy Portal and the AMI technology.

6.2.4 SELECTION PROCESS

115. Section 5.2(a)(iv) of Schedule 1 to the RIN requires JEN to explain the process by which JEN's project was selected, including its business case and consideration of any alternatives.

116. In 2007, the Victorian Government mandated that AMI meters be rolled out for consumers who have an annual consumption of 160MWh or less. These AMI meters have the potential to support in-home displays (**IHDs**). However, funding was not provided as part of the Victorian Government's program to develop the support for IHDs, which would allow consumers to obtain information about their consumption.

117. In the absence of funding for binding home area networks (**HANs**) and IHDs, the Energy Portal project was scoped and developed to provide as much consumption information to consumers as possible. The Energy Portal was delivered in the 2012 Regulatory Year; however, its capability as a demand management initiative was not explored. This was planned to commence in the Regulatory Year 2013.

118. JEN engaged an analyst (Community Online Communications Advisor) in the 2013 Regulatory Year for the following functions:

- Increase community connectivity by managing and enhancing JEN's digital reach, developing and managing marketing materials and promoting the benefits of the Energy Portal and the AMI technology, and
- Support Demand Management objectives of the business by developing questionnaires, carrying out surveys and analysing customers' behaviour.

119. JEN seeks approval for only the Demand Management initiative component of the project in the 2013 Regulatory Year under the DMIA. JEN considers this project to be the most cost effective option, because of the efficiencies gained by linking the Demand Management with the already approved Energy Portal and the AMI projects.

6.2.5 IMPLEMENTATION

120. Section 5.2(a)(v) of Schedule 1 to the RIN requires JEN to explain how JEN's initiative was implemented.

121. The project is being delivered through four phases as follows:

- Develop relevant questionnaires and strategies and carry out surveys to gauge customers' behaviour
- Select a control customer group among the Energy Portal customers
- Extract energy consumption usage of customers before their sign-up and after their sign-up to the Energy Portal, and
- Assess the impact of the Energy Portal on customers' consumption pattern and usage.

122. The project commenced in January 2013. Extraction and analysis of data is progressing and will continue through 2014.

6.2.6 IMPLEMENTATION COSTS

123. Section 5.2(a)(vi) of Schedule 1 to the RIN requires JEN to explain the implementation costs of JEN's project.

124. The actual expenditure for the project incurred in the 2013 Regulatory Year was $48,356, as set out in Appendix B - Template 23 (DMIS – DMIA) (Appendix 1-1 of JEN's response).

6.2.7 BENEFITS

125. Section 5.2(a)(vii) of Schedule 1 to the RIN requires JEN to explain any identifiable benefits that have arisen from JEN's project, including any off peak or peak demand reduction.

126. JEN believes it is still too early to fully quantify the Demand Management capabilities of the Energy Portal project. Nevertheless, the initial assessment of the surveys carried out so far indicates that the project is beneficial, as some consumers have already taken steps in reducing their electricity bill. An assessment of energy consumption change as a result of the Energy Portal take-up is being progressed and will be reported in the 2014 RIN.

6.2.8 ASSOCIATED COSTS

127. Section 5.2(b) of Schedule 1 to the RIN requires JEN to state whether the costs associated with JEN's initiative have been recovered under other schemes.

128. The associated costs for developing JEN's Energy Portal have not been:

- recovered under any other jurisdictional incentive scheme
- recovered under any other Commonwealth or State Government scheme, and
- included in the forecast capital or operating expenditure approved in the 2011-15 Distribution Determination or recovered under any other incentive scheme in that determination.

6.2.9 FORGONE REVENUE ASSUMPTIONS AND/OR ESTIMATES

129. Section 5.2(c) of Schedule 1 to the RIN requires JEN to explain any assumptions and/or estimates used in calculating forgone revenue, demonstrating the reasonableness of those assumptions and/or estimates in calculating forgone revenue, including the reasons for JEN's decision to adjust or not to adjust for other factors and the basis for any such adjustments.

130. Due to the limited availability of the Energy Portal project to JEN consumers in the 2013 Regulatory Year, JEN does not consider that its revenue has been impacted. Therefore, JEN does not seek to recover forgone revenue resulting from the Energy Portal project for the 2013 Regulatory Year.

131. As such, section 5.2(c) of Schedule 1 to the RIN is not applicable.

6.3 DEMAND MANAGEMENT INNOVATION ALLOWANCE

132. Section 5.3 of Schedule 1 to the RIN requires JEN to state the total amount of the DMIA spent in the Relevant Regulatory Year and explain how it was calculated.

133. The actual cost incurred in engaging an analyst to work on the Demand Management component of the project in the 2013 Regulatory Year was $48,356 as set out in Appendix B - Template 23 (DMIS – DMIA) (Appendix 1-1 of JEN's response).

134. The project cost (labour) is tracked in JEN's accounting systems[13].

[13] For the first 9 months of the 2013 Regulatory Year, a management estimate was used to split up the project cost between the Demand Management and the remainder of the project. For the remaining 3 months of the year, the project cost was tracked based on the actual time booked to the Demand Management component of the project by the analyst.

7. ADVANCED METERING INFRASTRUCTURE

135. In this section, JEN responds to section 6 of Schedule 1 to the RIN for the Relevant Regulatory Year 2013.

7.1 EFFICIENCY IMPROVEMENTS

136. Section 6.1 of Schedule 1 to the RIN requires JEN to provide a description and estimate of all efficiency improvements on JEN's operations directly or indirectly arising from or associated with the roll out of AMI.

137. As at the end of the 2013 Relevant Regulatory Year, no efficiency improvements arose in JEN's operations due to the roll out of AMI. However, JEN estimates that approximately $1.06M in customer benefits have been achieved arising from or associated with the roll out of AMI. These benefits accrue to customers and not to JEN.

Customer benefits realised through remote AMI services in 2013

138. Table 7-1 reveals the benefits achieved by JEN's AMI customers in 2013 through the provision of remote AMI services – first by lower charges and second by faster delivery of those services.

Table 7–1: Customer benefits from remote AMI services performed in 2013

Service	Remote AMI Services	Remote AMI Service Charge	Manual Service Charge	Customer benefit ($'000)
Re-energisation	6,009	$6.01	$14.60	$51.62
De-energisation	11,709	$6.01	$24.95	$221.77
Meter re-configuration	2,294	$37.96	$378.92	$782.16
Special meter read	533	$1.78	$10.79	$4.80
Total	20,545			$1,060.35

139. Remote service benefits accrue to JEN's customers through lower direct provision costs (avoided site visit) and customer charge. Relevant Alternate Control Services (**ACS**) and excluded services charges are shown in Table 7–1 and demonstrate the differential of remote AMI services when compared to manual services. This differential is the benefit being delivered to the customers. The indicated benefits relate to charges by the distributor and hence customer benefit may be greater, once retailer charges are included.

140. Remote AMI services replace manual services with the exception of special meter reads, which are reduced due to the availability of daily reads. Consequently, the customer benefit is underestimated in Table 7–1. In 2013 12,002 manual special reads were performed for customers without an AMI meter and charged $129,500. Manual reads will be further significantly reduced in 2014.

141. JEN anticipates further growth in direct customer benefits pertaining to AMI in the coming years. AMI is still a new system to most customers that introduces new features and services which cannot be directly compared with previous operational baselines. The inefficiencies associated with concurrently operating AMI and legacy metering systems will reduce when the AMI program is complete. The primary reasons for this are:

- As at the end of 2013, the AMI roll out on JEN's network was ongoing, with JEN still needing to simultaneously support both AMI and non-AMI meters; and

- The majority of operational activities associated with metering (such as meter reading, connection/disconnection of customer supplies) are outsourced. The costs of these outsourced activities have not been reduced in 2013, due to the need to maintain both AMI and non-AMI meters, and the slow, gradual take up of remote AMI services by retailers.

7.2 EFFICIENCY IMPROVEMENT (EXPLANATION AND QUANTUM)

142. Section 6.2 of Schedule 1 to the RIN requires JEN to explain, for efficiency improvements in response to paragraph 6.1, how the efficiency improvements arise from the roll out of AMI and to state the quantum of the efficiency improvements (if quantifiable).

143. While no efficiency improvements accrued directly to JEN, approximately $1.06M in customer improvements could be directly quantified in section 7.1 as a result of the AMI rollout. Many consumers with AMI meters are realising broader benefits and/or improved services derived from the JEN AMI rollout in the period including:

- Remote AMI Meter Reading
- Remote AMI Connection and Disconnection
- Remote AMI Meter Re-configuration
- Demand Management through Informed AMI Customers.

7.2.1 REMOTE AMI METER READING

144. As of 31 December 2013, a total of 285,000 JEN AMI meters are registered as type 5 in the market and remotely read with better than 98% ‘quality and quantity’ delivery of data to market daily. Therefore, most JEN AMI customers’ metering data:

- is available to the market operator by 6AM next business day
- is available to the retailer overnight before the opening of the business day;
- is available to the customer via the web portal “Electricity Outlook” for analysis and information (customer registration required);
- has improved billing accuracy with straight through processing and less human intervention.

145. Notably, retailer disputes relating to contested consumption in the majority of instances involved a non-AMI meter. Therefore, automated remote AMI meter reading has reduced the number of disputes, realisinga benefit for the consumer and energy market.

7.2.2 REMOTE AMI CONNECTION AND DISCONNECTION

146. In 2013, 35,656 connections and 35,883 disconnections were performed, of which 17,718 (or 24.7%) were performed remotely using AMI enabled systems. Remote connection/disconnection eliminates the need for a site visit and so JEN customers benefit directly via lower charges and improved service delivery (refer Table 7–1. Of the total manual connection and disconnections, 34,972 (or 49%) were required because an AMI meter was not installed. With 90% of AMI meters deployed at the end of 2013, the requirement for manual fuse pulls will drop dramatically in 2014 and beyond. It is important to note that fuse removals and service removals are still required for AMI-enabled network connections when, for instance, electrical works require that the supply be isolated at the fuse or connection point.

7.2.3 REMOTE AMI METER RE-CONFIGURATION

147. When a customer installs co-generation (e.g. solar system), the metering installation is required to be altered to measure energy exported to the grid. When an AMI meter has previously been installed, this operation is performed by remote re-configuration, improving service delivery efficiency through the avoidance of a site visit. JEN customers also benefit via lower charges (refer Table 7–1). In 2013, JEN performed 2,294 remote re-configurations.

7.2.4 DEMAND MANAGEMENT THROUGH INFORMED AMI CUSTOMERS

148. Customers gained benefit from prompt feedback of their energy use. By the end of 2013, 4,591 customers registered for the Jemena Electricity Outlook web portal to gain access to 30-minute energy consumption data and comparison with other consumers. The effectiveness of portal use and changed energy usage is subject to ongoing study.

8. SAFETY AND BUSHFIRE RELATED EXPENDITURE

149. In this section, JEN responds to section 7 of Schedule 1 to the RIN for the 2013 Regulatory Year.

8.1 ASSET CATEGORIES

150. Section 7.1 of Schedule 1 of the RIN requires JEN to specify and define the relevant Asset Category to which each safety and bushfire related expenditure item relates.

151. The list of each safety and bushfire related expenditure and the relevant Asset Category to which it relates is set out in Table 8-1.

Table 8-1: Safety and bushfire expenditure and Asset Category

Safety & bushfire related expenditure	Asset Categories
Planned non-preferred services replacements	Conductor – LV Services *Low voltage insulated conductor typically runs from a pole to a point of attachment at the customer's premise for the purpose of supplying electricity.*
Planned replacement of non-preferred services due to height	Conductor – LV Services *Low voltage insulated conductor typically runs from a pole to a point of attachment at the customer's premise for the purpose of supplying electricity.*
Removal of public lighting switch wire (spans)	No applicable asset category *Public lighting switch wire is no longer utilised on the network as the mechanism to turn on street lighting. Today, public lighting is PE cell controlled.*
Replacing existing Single Wire Earth Return (**SWER**) lines with 22kV overhead bare conductor (km)	Conductor - HV Bare Conductor *High voltage uninsulated conductor, which is used as mains conductor on a feeder for the purpose of supplying electricity.*
Installing Ground Fault Neutraliser (**GFN**) and associated equipment at zone substations	Zone Substation – Others *A GFN, also known as a Rapid Earth Fault Current Limiter (REFCL), is installed inside a zone substation and has the purpose of limiting earth fault current.*
Replacing crossarms/insulator sets – pole top fire mitigation	Pole top structures – wooden crossarm HV and Pole top structures - wooden crossarm ST *A structure mounted on the top of a pole and, in this case typically consisting of a wooden crossarm and porcelain insulators. The purpose is to support overhead conductors.*
Replacing crossarms – based on age and condition	Pole top structures – wooden crossarm ST, Pole top structures – wooden crossarm HV and Pole top structures – wooden crossarm LV *A structure mounted on the top of a pole and, in this case typically consists of a wooden crossarm and porcelain insulators. The purpose is to support overhead conductors.*

Safety & bushfire related expenditure	Asset Categories
Replacing poles – based on age and condition	Poles *A pole may be made of wood, steel or concrete, the purpose of which is to support the pole top structure, public lights and overhead conductors.*
Stake poles – based on age and condition	Poles - Staked Poles *A pole may be made of wood, steel or concrete. The purpose is to support the pole top structure, public lights and overhead conductors. In this case the pole has been reinforced with steel stakes.*
Replacing undersized poles	Poles *A pole may be made of wood, steel or concrete, the purpose of which is to support the pole top structure, public lights and overhead conductors.*
Staking undersized poles	Poles – Staked Poles *A pole may be made of wood, steel or concrete. The purpose is to support the pole top structure, public lights and overhead conductors. In this case the pole has been reinforced with steel stakes.*
Replacing overhead conductor – mainly steel	Conductor - HV Bare Conductor *High voltage uninsulated conductor which is used as mains conductor on a feeder for the purpose of transporting electricity.*
Service line clearance – overhead services requiring relocation or undergrounding	Conductor – LV Services *Low voltage insulated conductor typically runs from a pole to a point of attachment at the customers premise for the purpose of supplying electricity.*
Distribution Transformer Height Rectification	Distribution - Others *Distribution transformers may be installed in kiosks, in ground mounted enclosures, inside buildings or mounted on poles. The purpose of the transformer is to step down the voltage. The distribution transformer height rectification refers to work required to raise the height of pole-mounted transformer.*
Vibration Dampers and Armour Rods	Conductor - HV Bare Conductor *High voltage uninsulated conductor which is used as mains conductor on a feeder for the purpose of supplying electricity.*
Zone Substation Earth Grid replacements	Zone Substation – Others *Earth grids at zone substations are designed to reduce the step and touch potential. Step Potential is the difference in voltage between two points on the ground that a person could touch in one step, and Touch Potential is the difference in voltage between a point on the ground and that of a conductive material within arms reach.*
Trial of Neutral Condition Monitor	Others *The purpose of the neutral condition monitor is to improve public health and safety through continuous monitoring of the integrity of the supply neutral.*

8.2 VARIANCE ANALYSIS

152. Section 7.2 of Schedule 1 to the RIN requires JEN to identify each material difference (where the difference is equal to or greater than 10 per cent), in relation to the asset categories specified in response to paragraph 7.1.

153. While section 7.2 of Schedule 1 to the RIN requires a variance analysis in relation to asset categories, the forecast volume and expenditure information included in the AER's 2011-15 Distribution Determination has not always been presented by asset category. As such, JEN has only provided variance analysis by asset category where possible. Otherwise, JEN has provided variance analysis by program in this section.

8.2.1 VARIANCE ANALYSIS - VOLUME

154. Section 7.2(a) of Schedule 1 to the RIN requires JEN to identify each material difference between actual and forecast volumes. The variance analysis for each material difference is set out in Table 8-2.

Table 8-2: Actual volume vs forecast volume

Asset Categories	Units	Actual	Allowance	Variance %
Removal of public lighting switch wire	spans	2,077	1,700	+22%
Pole top structures	poles	4,412	3,390	+30%
Poles	poles	470	536	-12%
Poles - staked poles	poles	1,107	443	+150%

(1) where annual volume data has not been included in the AER's final determination, JEN divided the five year cumulative amount to derive the forecast for 2013 to facilitate the required variance analysis.

8.2.2 VARIANCE ANALYSIS - EXPENDITURE

155. Section 7.2(b) of Schedule 1 to the RIN requires JEN to identify each material difference between actual and forecast expenditure. The variance analysis for each material difference is set out in Table 8-3. When considering the variances it should be noted that the actual expenditure has been expressed in nominal dollars and the forecast expenditure has been expressed in both 2010 dollars and converted to nominal dollars to facilitate variance analysis.

Table 8-3: Actual expenditure vs forecast expenditure

Asset Category	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Conductor – LV services	5.23	2.13	2.31	+126%
Conductor - HV bare conductor	2.70	1.81	1.96	+38%
Pole top structures	4.24	7.05	7.65	-45%
Zone substation - others	0.02	0.93	1.00	-98%
Removal of public lighting switch wire	0.54	0.32	0.35	+54%
Poles	4.30	2.70	2.93	+47%
Poles – staked poles	1.65	0.34	0.37	+341%

8.2.3 VARIANCE ANALYSIS - UNIT COSTS

156. Section 7.3(c) requires JEN to identify each material difference between actual and forecast unit costs. The variance analysis for each material difference (by program) is set out in Table 8-4. When considering the variances it should be noted that the actual unit rate has been expressed in nominal dollars and the forecast unit rate has been expressed in both 2010 dollars, as per the AER's RIN template, as well as nominal dollars to facilitate variance analysis.

Table 8-4: Actual unit costs Vs forecast unit costs

Program	Actual $Nominal	Allowance $Real2010	Allowance $Nominal	Variance %Nominal
Planned non-preferred services replacements	[redacted]	[redacted]	[redacted]	+221%
Planned replacement of non-preferred services due to height	[redacted]	[redacted]	[redacted]	+221%
Removal of public lighting switch wire	[redacted]	[redacted]	[redacted]	+15%
Replacing existing Single Wire Earth Return (**SWER**) lines with 22kV overhead bare conductor (km)	[redacted]	[redacted]	[redacted]	-32%
Installing Ground Fault Neutraliser (**GFN**) and associated equipment at zone substations	[redacted]	[redacted]	[redacted]	-100%
Replacement of crossarms – based on age and condition	[redacted]	[redacted]	[redacted]	+72%
Replacement of poles – based on age and condition	[redacted]	[redacted]	[redacted]	+145%
Stake poles – based on age and condition	[redacted]	[redacted]	[redacted]	+65%
Replacing undersized poles	[redacted]	[redacted]	[redacted]	+113%
Staking undersized poles	[redacted]	[redacted]	[redacted]	+58%
Replacement of overhead conductor – mainly steel	[redacted]	[redacted]	[redacted]	-33%
Service line clearance – overhead services requiring relocation or undergrounding	[redacted]	[redacted]	[redacted]	+488%
Service line clearance – overhead services requiring relocation or undergrounding	[redacted]	[redacted]	[redacted]	+100%
Vibration dampers and armour rods	[redacted]	[redacted]	[redacted]	n.m.
Distribution transformer height rectification	[redacted]	[redacted]	[redacted]	n.m.
Zone Substation earth grid replacements	[redacted]	[redacted]	[redacted]	n.m.

14 The unit costs are commercially confidential to JEN and could harm JEN's legitimate business interests and future negotiations with service providers if published. This applies to all unit cost data reported in Schedule 1.

8.3 REASONS FOR VARIANCES BY PROGRAM

157. Section 7.3 of Schedule 1 to the RIN requires JEN to provide reasons for each material difference identified in the response to paragraph 7.2.

158. As stated in section 8.2 of JEN's response, the forecast information included in the 2011-15 Distribution Determination has not always been presented by asset category. Besides, the data required and the analysis carried out in Template 27 of Appendix B (Appendix 1-1 of JEN's response) has been presented by program. Hence, JEN provides reasons for material differences by program in this section. In section 8.4 of JEN's response, JEN provides analysis by asset category, where possible, cross referencing to section 1.

8.3.1 PLANNED NON-PREFERRED SERVICE REPLACEMENTS

159. The material variances in relation to planned non-preferred service replacements are set out in Table 8–5.

Table 8–5: Planned non-preferred service replacements

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	4,615	6,000	6,000	-23%
Expenditure ($M)	5.12	1.93	2.09	+145%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	+221%

Volume variance

160. Services are upgraded to current standards as a proactive replacement program and in conjunction with other work such as network augmentation, pole replacement, reconductoring and asset relocation. Particular attention is paid to the types of open wire, red lead and neutral screened services which exhibit historical trends of deterioration.

161. The materially lower than forecast volume of work completed in 2013 was due to priority being given to a similar, but distinct type of replacement—'Planned replacement of non-preferred services due to height' which was higher than forecast. Also contributing to the lower than forecast volume of work in 2013 was the significant number of post-construction field audits that were completed in January 2014 for services installed in 2013. These replacement services were entered into the asset database in Q1 2014 and will be included in the 2014 reported volumes.

162. JEN is well advanced with the detailed scoping of the specific services that will be targeted for replacement and will achieve the forecast volume of planned non-preferred service replacements in 2014.

Unit cost variance

163. The unit rate of [[redacted]] is the actual unit rate cost to replace non-preferred services and non-compliant services due to height. JEN is unable to report the unit rates for each type of replacement, as the data is not collected separately. Examining the total project cost, total length of service conductor used, and the average length of an overhead service, the 2013 replacement cost was determined.

164. JEN's proposed unit rate of [[redacted]] was based on assuming that economies of scale were achieved through replacing services on consecutive premises. This would be achieved through reducing travel time between jobs both at the time of construction and auditing. There would also be a reduction in traffic management costs. These economies of scale have not been realised, because in 2013, JEN has continued to address the services

with the lowest ground clearance in order to minimise the risk associated with low services. These services are located across the network rather than in concentrated locations.

Expenditure variance

165. The expenditure variance is due including expenditure for the planned replacement of non-preferred services due to height, which has a higher unit rate. JEN is unable to report the expenditure for each type of replacement, as the cost for the two programs is not collected separately. The higher unit cost has contributed to a materially higher than forecast expenditure in 2013.

166. Also contributing to the higher than forecast expenditure in 2013 is the inclusion of the cost to replace the non-preferred services in 2013, but where the post-construction field audits were completed in January 2014. These replacement services were only entered into the asset database in Q1 2014 and are not included in the 2013 reported volumes.

8.3.2 PLANNED REPLACEMENT OF NON-PREFERRED SERVICES DUE TO HEIGHT

167. The material variances in relation to planned replacement of non-preferred service due to height are set out in **Table** 8-6.

Table 8-6: Planned replacement of non-preferred service due to height

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %
Volume (units)	1,735	341	341	+409%
Expenditure ($M)	-	0.11	0.12	-100%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	+221%

Volume variance

168. The materially higher than forecast volume of work completed in 2013 was due to priority being given to a similar, but distinct type of replacement—'Planned replacement of non-preferred services due to height'.

Unit cost variance

169. As stated in paragraph 163, the unit rate of [[redacted]] is the actual unit rate cost to replace non-preferred services and non-compliant services due to height. JEN is unable to report on the unit rate costs separately in 2013, as the data is not collected separately. JEN's proposed unit rate of [[redacted]] was based on assuming economies of scale were achieved by replacing services on consecutive premises. As described above in paragraph 164, JEN has not achieved these economies of scale.

Expenditure variance

170. The expenditure variance is due to the relevant costs having been reported under planned non-preferred service replacements. JEN is unable to report the expenditure for each type of replacement as the cost is not collected separately.

8.3.3 PUBLIC LIGHTING SWITCH WIRE REMOVAL

171. The material variances in relation to public lighting switch wire removal are set out in **Table** 8-7.

Table 8-7: Public lighting switch wire removal

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	2,077	1,700	1,700	+22%
Expenditure ($M)	0.54	0.32	0.35	+54%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	+15%

Volume variance

172. The materially higher than forecast volume is a timing issue. JEN delivered a higher volume in 2013 in order to recover the lower than forecast volume in 2012. This program is on target to deliver the forecast total volume over the regulatory period.

173. Public lighting switch wires are removed primarily as part of a proactive program, as well as in conjunction with other work, such as network augmentation, pole replacement, re-conductoring and asset relocation.

Unit cost variance

174. The higher unit rate cost in 2013 is as result of a variation in complexity of work sites, particularly with regard to requirements for traffic management. A more meaningful comparison of unit rates will be to compare the average unit rate over the 5 year program of work.

Expenditure variance

175. The higher unit cost has contributed to the expenditure variance.

8.3.4 REPLACING EXISTING SWER LINES WITH 22KV OVERHEAD BARE CONDUCTOR

176. The material variances in relation to replacing existing SWER lines with 22kV overhead bare conductor are set out in **Table** 8-8.

Table 8-8: Replacing existing SWER lines with 22kV overhead bare conductor

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	14	3	3	+438%
Expenditure ($M)	2.14	0.45	0.49	+339%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	-32%

Volume variance

177. The actual volume of replacement was materially higher than forecast, because the actual construction (replacement) associated with this project was completed in 2013. The entire volume of SWER was removed from the JEN network and replaced in one consolidated project, whereas the annual volume in the allowance was the five year cumulative amount divided by five.

Unit cost variance

178. JEN achieved economies of scale through replacing the SWER network as a consolidated project in 2013, rather than in sections over a number of years. This was likely achieved through reducing travel time between jobs both at the time of construction and auditing. There would also have been a reduction in traffic management costs.

Expenditure variance

179. The higher volume has contributed to the expenditure variance. JEN replaced 13km of SWER lines with 22kV overhead bare conductor in 2013.

8.3.5 REPLACING CROSSARMS - BASED ON AGE AND CONDITION

180. The material variances for replacing crossarms – based on age and condition are set out in **Table** 8-9.

Table 8-9: Replacing crossarms – based on age and condition

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	4,098	2,823	2,823	+45%
Expenditure ($M)	3.04	5.60	6.07	-50%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	+72%

Volume variance

181. JEN's asset inspection program assesses the serviceability of crossarms based on condition. Crossarms are replaced when they reach the end of their service life. This means the actual volume of crossarms replaced may show variation from year to year, depending on the asset inspection program and the areas covered in each year's program.

182. However, the forecast included in the 2011-15 Distribution Determination is determined by dividing the cumulative amount by five – to accord with the five year regulatory control period.

Unit cost variance

183. In its EDPR submission, JEN proposed separate unit replacement rates and volumes for low voltage (**LV**), high voltage (**HV**) and subtransmission (**ST**) crossarms. The AER determined a single unit rate for crossarm replacement based on a weighted average calculation. The result was a unit rate weighted in favour of LV crossarms which has the lowest unit rate and the highest proposed volume in JEN's 5-year proposal (the split between LV, HV, ST crossarm volumes was 80, 16 and 4% respectively). Moreover, in the final determination the AER reduced JEN's proposed unit cost by 15%.

184. For the reason stated below, in expenditure variance, JEN cannot determine the unit cost by simply dividing the total expenditure with the volume of crossarm replacement. JEN has examined a large number of work orders for crossarm replacements undertaken in 2013 in detail to determine the replacement cost for 2013. In 2013 the ratio of LV, HV, ST crossarms replaced was 47, 35, 17% respectively. As the unit replacement cost for HV and ST crossarms is higher than that of an LV crossarm due to the complexity of the pole structure, the weighted average unit rate for 2013 is higher than the AER's unit rate.

Expenditure variance

185. Crossarms are also replaced as a result of network augmentation programs in addition to asset replacement programs. Replacing crossarms as part of a network augmentation project results in the cost of the crossarm replacement being captured as a part of the network augmentation project, with these costs not being separately identified.

186. With the costs captured under network augmentation projects, the cost for replacing crossarms – based on age and condition has been understated. This understatement has contributed to the material variance in total expenditure.

187. JEN has completed the implementation of a solution to improve the activity counting and cost allocation processes and this will be utilised in 2014.

8.3.6 REPLACING POLES - BASED ON AGE AND CONDITION

188. The material variances for replacing poles – based on age and condition are set out in

189. **Table** 8-10.

Table 8-10: Replacing poles – based on age and condition

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	395	259	259	+53%
Expenditure ($M)	3.38	1.36	1.48	+129%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	+145%

Volume variance

190. JEN's asset inspection program comprises a technical measurement procedure to determine the serviceability of wood and steel poles. Poles are replaced after reaching the end of their service life and are unsuitable for staking. As poles are replaced based on condition, pole replacement volume is expected to vary from year to year.

191. The volume and complexity of the poles that require replacement each year will be influenced by the characteristics of the particular pole inspection zone (geographical area) that is inspected in that year. Some inspection zones will result in higher volumes and more complex poles to be replaced when compared with other zones.

Unit cost variance

192. The higher than forecast unit cost is the result of the variation in the ratio of subtransmission, high voltage, low voltage and public lighting poles that require replacement. In other words, if there is a high proportion of complex poles, particularly high voltage, the unit cost will be higher than forecast.

193. Further, the forecast unit cost was calculated using a total replacement volume and cost over a number of years, rather than just one year.

194. JEN believes this different calculation basis contributed to the variance.

Expenditure variance

195. The higher than forecast unit cost and volume have contributed to the higher actual expenditure.

8.3.7 STAKE POLES - BASED ON AGE AND CONDITION

196. The material variances for stake poles – based on age and condition are set out in **Table** 8-11.

Table 8-11: Stake poles – based on age and condition

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	405	223	223	+82%
Expenditure ($M)	0.62	0.17	0.19	+230%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	+65%

Volume variance

197. JEN's asset inspection program comprises a technical measurement procedure to determine the serviceability of wood and steel poles. Poles that are assessed as being suitable are staked after reaching the end of their service life. As poles are staked based on condition, pole staking volume is expected to vary from year to year.

198. Similar to the pole replacement activity (paragraph 191), the volume and complexity of the poles that require staking each year will be influenced by the characteristics of the particular pole inspection zone (geographical area) that is inspected in that year. Some inspection zones will result in higher volumes and more complex poles to be staked when compared with other zones.

Unit cost variance

199. In JEN's proposal, the split between LV, HV, ST pole staking volumes was 53%, 41% and 7% respectively. In 2013 the ratio of LV, HV and ST poles staked was 33%, 49% and 18% respectively. Therefore, the higher than forecast unit cost is the result of the variation in the ratio of types of poles that required staking.

200. Further, the forecast unit cost was calculated using a total staking volume and cost over a number of years rather than just one year.

201. JEN believes this different calculation basis contributed to the variance.

Expenditure variance

202. The higher than forecast unit costs and volumes have contributed to the higher than forecast expenditure.

8.3.8 REPLACING UNDERSIZED POLES

203. The material variances for replacing undersized poles are set out in **Table** 8-12.

Table 8-12: Replacing undersized poles

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	75	277	277	-73%

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Expenditure ($M)	0.92	1.23	1.34	-31%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	+113%

Volume variance

204. Assessing undersized poles identified that a higher than forecast percentage of the poles are suitable for staking. This means that a lower than forecast volume will be replaced. JEN expects to treat the total forecast number of undersized poles by the end of the 2011-15 Distribution Determination period, although the proportion that will be staked will be higher than forecast.

Expenditure variance

205. The lower than forecast volume has contributed to the lower than forecast expenditure.

Unit cost variance

206. The higher than forecast unit cost is the result of the variation in the ratio of subtransmission, high voltage, low voltage and public lighting poles that require replacement. Similar to pole replacement, which was explained in section 8.3.6 if there is a high proportion of complex poles, particularly high voltage, the unit cost will be higher than forecast.

207. Further, the forecast unit cost was calculated using a total replacement volume and cost over a number of years rather than just one year.

208. JEN believes this different calculation basis contributed to the variance.

8.3.9 STAKE UNDERSIZED POLES

209. The material variances for stake undersized poles are set out in **Table** 8-13.

Table 8-13: Stake undersized poles

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	702	220	220	+219%
Expenditure ($M)	1.02	0.16	0.17	+500%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	+58%

Volume variance

210. An assessment of undersized poles has identified that a higher than forecast percentage of the poles are suitable for staking. This means that a higher than forecast volume will be staked. JEN expects to treat the total forecast number of undersized poles by the end of the 2011-15 Distribution Determination period, although the proportion that will be staked will be higher than forecast.

Unit cost variance

211. The higher than forecast unit cost is the result of the variation in the ratio of LV, HV and ST poles that required staking. In order to minimise network risk, JEN has addressed the ST and HV poles in the earlier years of the

period. Further, the forecast unit cost was calculated using a total staking volume and cost over a number of years rather than just one year.

212. JEN believes this different calculation basis contributed to the variance.

Expenditure variance

213. The higher than forecast unit cost and higher than forecast completed volume has contributed to the higher than forecast expenditure.

8.3.10 REPLACING OVERHEAD CONDUCTOR - MAINLY STEEL

214. The material variances for replacing overhead conductor – mainly steel are set out in Table 8-14.

Table 8-14: Replacing overhead conductor – mainly steel

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	12	22	22	-46%
Expenditure ($M)	0.56	1.32	1.43	-61%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	-33%

Volume variance

215. Although the volume was lower than forecast for 2013, the overhead conductor replacement program is ahead of target in the Hazardous Bushfire Risk Area (**HBRA**) for the 2011-15 Distribution Determination period.

Unit cost variance

216. The unit rate cost will vary depending on the complexity of the specific project. The complexity is impacted by the ability to obtain access to the assets when the work needs to be undertaken and the length of the conductor replacement. JEN experienced a higher proportion of longer length projects in 2013, resulting in more efficient project delivery.

Expenditure variance

217. The unit cost and volume variance has contributed to the lower than forecast expenditure.

8.3.11 SERVICE LINE CLEARANCE - OVERHEAD SERVICES REQUIRING RELOCATION

218. The material variances for service line clearance – overhead services requiring relocation are set out in **Table** 8-15.

Table 8-15: Service line clearance – overhead services requiring relocation

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	48	57	57	-16%
Expenditure ($M)	0.11	0.02	0.02	+490%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	+488%

Volume variance

219. Overhead services requiring relocation is driven by the new *Electricity Safety (Electric Line Clearance) Regulations 2010* (**Clearance Regulations**). The Clearance Regulations require an increase in clearance requirements for overhead power lines that JEN must comply with under the *Electricity Safety Act 1998*.

220. The options available to ensure compliance are the vegetation management program, overhead services relocation or undergrounding. Overhead services relocation or undergrounding could take place when the vegetation management program is not able to meet the clearance requirements (as stipulated in the Clearance Regulations) without permanently damaging the tree or adversely affecting the aesthetics of the vegetation.

221. In 2013 JEN continued identifying the overhead services in need of relocation via its vegetation inspection cycle. Upon completing the third year of the Service Line Clearance program, it has become evident that the volume of service lines that require relocation in order to achieve compliance is lower than the original forecast. This forecast was based on the best information available at the time of the EDPR submission.

222. JEN did, however, underestimate the volume of other assets that would require relocation or replacement. In order to ensure compliance, it has been necessary for JEN, in 2013, to not only relocate 48 services, but to replace 2 spans of LV open wire conductor with LV ABC, replace 1 pole and install two offset crossarms.

Unit cost variance

223. JEN's proposed unit rate was based on assuming that economies of scale were achieved through relocating services on premises in close proximity. This would be achieved through reducing travel time between jobs both at the time of construction and auditing. There would also be a reduction in traffic management costs. These economies of scale have not been realised, because in 2013 JEN has not identified a significant volume of service lines that require relocation in order to achieve compliance. The services requiring relocation in 2013 were located across the network rather than in concentrated locations.

224. In addition, the unit cost calculation is impacted by the inclusion of the cost associated with the replacement of two spans of LV open wire conductor with LV ABC, replacement of one pole and installation of two offset crossarms.

Expenditure variance

225. The cost associated with relocating 48 services, replacing two spans of LV open wire conductor with LV ABC, replacing one pole and installing two offset crossarms are included in the expenditure. Therefore, although there is a large volume variance in the number of overhead services relocated, the expenditure variance is smaller on the basis that the expenditure is not only related to overhead services.

8.3.12 SERVICE LINE CLEARANCE - OVERHEAD SERVICES REQUIRING UNDERGROUNDING

226. The material variances for Service line clearance – overhead services requiring undergrounding are set out in **Table** 8-16.

Table 8-16: Service line clearance – overhead services requiring undergrounding

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	-	14	14	+100%
Expenditure ($M)	-	0.07	0.07	+100%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	+100%

227. As stated in section 8.3.11, the undergrounding of overhead services is one of the options to ensure compliance with the Clearance Regulations.

Volume and expenditure variance

228. JEN did not identify opportunities for any undergrounding work in 2013. JEN has continued to utilise its vegetation inspection cycle to identify any potential services that require an underground solution. As described in section 8.3.11, JEN has relocated and replaced a range of overhead assets in order to achieve compliance.

8.3.13 VIBRATION DAMPERS AND ARMOUR RODS

229. The material variances for vibration dampers and armour rods are set out in

230. **Table** 8-17.

Table 8-17: Vibration dampers and armour rods

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (sets) – Vibration Dampers	390	-	-	+100%
Volume (spans) - Armour Rods	76	-	-	+100%
Expenditure ($M)	0.27	-	-	+100%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	+100%

231. In response to the Victorian Bushfires Royal Commission, Energy Safe Victoria (**ESV**) issued a directive to JEN under the *Electricity Safety Act (1998)* which requires, in part, that vibration dampers and armour rods be installed on all conductors on the network as per network standards.

232. JEN prepared a plan to retrofit vibration dampers and armour rods in accordance with construction standards by 2015.

233. The ESV directive was issued after JEN submitted its revised proposal (in July 2010) to the AER. As such, the AER has not allowed expenditure for this safety program of work in its 2011-15 Distribution Determination.

8.3.14 DISTRIBUTION TRANSFORMER HEIGHT RECTIFICATION

234. The material variances for distribution transformer height rectification are set out in **Table** 8-18.

Table 8-18: Distribution transformer height rectification

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	-	-	-	+100%
Expenditure ($M)	0.09	-	-	+100%
Unit Cost ($)	-	-	-	+100%

235. The Electricity Safety (Network Assets) Regulations 1999 (**Safety Regulations**) require the supporting platform and equipment for a pole-mounted substation to be a certain minimum distance above ground level.

236. To comply with the Safety Regulations, JEN initiated a program to rectify the distribution transformer height under its Electricity Safety Management Scheme (**ESMS**). The program aims to rectify pole substation platform height non-conformances that have been identified by inspection programs.

237. JEN included the costs for the program in its revised proposal (July 2010). However, the 2011-15 Distribution Determination does not allow for the cost to comply with the Safety Regulations on transformer heights. Notwithstanding the zero allowance, JEN proceeded to carry out works in compliance with the Safety Regulations. The costs in 2013 were associated with the planning, scoping and design of the transformer platforms that will be addressed in 2014.

8.3.15 ZONE SUBSTATION EARTH GRID REPLACEMENTS

238. The material variances for zone substation earth grid replacements are set out in **Table 8-19**.

Table 8-19: Zone substation earth grid replacements

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume (units)	4	-	-	+100%
Expenditure ($M)	0.23	-	-	+100%
Unit Cost ($)	[redacted]	[redacted]	[redacted]	+100%

239. The Safety Regulations require distribution businesses to manage earthing systems to ensure safety compliance. The safety compliance relates principally to ensure the step and touch voltages in high risk or well-frequented areas are kept within industry standards. This is to ensure that the earthing and electrical protection systems safely manage abnormal supply network conditions to avoid risk to people or damage to property.

240. Earth grids at zone substations are designed to reduce the step and touch potential. Step potential is the difference in voltage between two points on the ground that a person could touch in one step, and touch potential is the difference in voltage between a point on the ground and that of a conductive material within arm's reach.

241. JEN included the costs for the earth grid replacement in its revised proposal (July 2010). However, the 2011-15 Distribution Determination does not provide for the cost to comply with the Safety Regulations on earthing system safety. Notwithstanding the zero allowance, JEN proceeded to carry out works in compliance to the Safety Regulations. However, no earth grid was identified for replacement in 2013.

8.3.16 TRIAL OF NEUTRAL CONDITION MONITOR

242. The material variances for trial of neutral condition monitor are set out in **Table 8-20**.

Table 8-20: Trial of neutral condition monitor

	Actual $Nominal	Allowance $Real 2010	Allowance $Nominal	Variance %Nominal
Volume	-	-	-	-
Expenditure	-	-	-	-

243. JEN included a proposal for the trial of a neutral condition monitors in its 2010 regulatory proposal. The trial aims to improve public health and safety through continuous monitoring of the integrity of the supply neutral.

244. In 2010 and 2011, JEN developed an algorithm called Customer Supply Monitoring (**CSM**) that can be deployed into existing generation of smart meters installed on JEN's network to achieve the neutral condition monitor function.

245. In late 2012 and 2013, JEN began the process of seeking a partner to commercialise the algorithm. Unfortunately, no commercial partner has been found.

246. As a result, JEN did not incur expenditure in 2013 on the neutral condition monitor trial.

8.4 REASONS FOR MATERIAL DIFFERENCES BY ASSET CATEGORY

247. Section 7.3 of Schedule 1 to the RIN requires JEN to provide reasons for each material difference identified in the response to paragraph 7.2.

248. Due to the limitations stated in section 8.3 of JEN's response, JEN provides reasons for each material difference by program in that section. In this section 8.4, JEN provides variance analysis by asset category where possible, cross referencing to section 8.3.

8.4.1 VOLUME VARIANCE

249. The volume variances by asset category are set out in **Table** 8**-**21.

Table 8-21: Volume variance by Asset Category

Asset Category	Variance	Reasons for Variance
Not applicable asset category (Removal of public lighting switch wire (spans))	Actual volume materially higher than forecast	Refer to section 8.3.3 of JEN's response
Pole top structures	Actual volume materially higher than forecast	Refer to section 8.3.5of JEN's response
Poles	Actual volume materially lower than forecast	Refer to section 8.3.6 and 8.3.8 of JEN's response
Poles – staked poles	Actual volume materially higher than forecast	Refer to section 8.3.7 and 8.3.9 of JEN's response

8.4.2 EXPENDITURE VARIANCE

250. The expenditure variances by asset category are set out in Table 8-22.

Table 8-22: Expenditure variances by Asset Category

Asset Category	Variance	Reasons for Variance
Conductor – LV services	Actual expenditure materially higher than forecast	Refer to sections 8.3.1, 8.3.2, 8.3.11 and 8.3.12 of JEN's response
Conductor – HV bare conductor	Actual expenditure materially higher than forecast	Refer to sections 8.3.4 and 8.3.10 of JEN's response8.3.1
Pole top structures	Actual expenditure materially lower than forecast	Refer to section 8.3.5 response

Asset Category	Variance	Reasons for Variance
Zone substation - others	Actual expenditure materially lower than forecast	Refer to sections 8.3.15 of JEN's response
No applicable asset category (Removal of public lighting switch wire (spans)	Actual expenditure materially higher than forecast	Refer to sections 8.3.3 of JEN's response

8.5 REASONS FOR DIFFERENCES BETWEEN THE ACTUAL VOLUMES SUBMITTED AS PART OF THE ESMS AND RAS

251. Section 7.4 of Schedule 1 to the RIN requires JEN to provide reasons for any difference between the actual volumes submitted as part of the ESMS to Energy Safe Victoria and that in the RAS.

252. This requirement is not applicable as there is no difference between the actual volumes submitted as part of the ESMS and that in the RAS.

9. NON-FINANCIAL PERFORMANCE MONITORING INFORMATION

253. In this section, JEN responds to Section 8 of Schedule 1 of the RIN for the 2013 Relevant Regulatory Year.

254. Section 8 of Schedule 1 to the RIN requires JEN to explain all material differences (where the difference is equal to or greater than 10%) between the target performance measure specified in the *Service Target Performance Incentive Scheme* (**STPIS**) and actual performance reported in response to paragraph 1.1(b) in section 1 of Schedule 1 to the RIN.

255. The material variances and explanations are set out below.

9.1 STPIS RELIABILITY

256. The performance measures used in assessing STPIS reliability are as follows:

- Urban unplanned average sustained interruptions (System Average Interruption Frequency Index) (**SAIFI**)
- Urban unplanned average minutes off supply (System Average Interruption Duration Index) (**SAIDI**)
- Rural unplanned average sustained interruptions (SAIFI)
- Rural unplanned average minutes off supply (SAIDI); and
- Rural unplanned average momentary interruptions (**MAIFI**).

257. The comparison between actual and target STPIS reliability measures is set out in Table 9-1.

Table 9-1 STPIS reliability

Performance Measure		2013 Actual	2013 Target	Variance
Urban (after removing excluded events and Major Event Day (**MED**))	Unplanned average minutes off supply (SAIDI)	57.5	68.5	-16%
	Unplanned average sustained interruptions (SAIFI)	1.06	1.13	-6%
	Unplanned average momentary interruptions (MAIFI)	0.70	0.78	-10%
Rural (after removing excluded events and MED)	Unplanned average minutes off supply (SAIDI)	114.4	153.2	-25%
	Unplanned average sustained interruptions (SAIFI)	2.42	2.59	-7%
	Unplanned average momentary interruptions (MAIFI)	2.39	1.94	+23%

258. Three STPIS performance measures show a variance of greater than 10% as set out in Table 9-1. Two of these variances were associated with better than target levels of performance, whilst one was associated with worse performance than target The two main factors contributing to the favourable performance are:

- JEN's more stringent vegetation management practice and JEN's focus on targeted asset replacement, network augmentation and maintaining network performance; and

- Mild temperatures experienced in the 2012/13 summer, along with infrequent storm events during the historically stormy months of August and September.

259. The main factor contributing to the unfavourable rural MAIFI performance is a significant reduction in the rural customer base, compared with 2012. This is as a result of reclassifying a feeder from rural to urban.

9.2 STPIS CUSTOMER SERVICE

260. The performance measures used in assessing STPIS customer service are as follows:

- Appointments not met on time (excluding AMI)
- Guaranteed Service Levels (**GSL**) – New connections not made on or before the date agreed
- GSLs – Low reliability payments
- GSLs – Street lights and
- Call centre performance.

261. The comparison between actual and target STPIS customer service measures is set out in Table 9-2.

Table 9-2 STPIS customer service

Performance Measure	2013 Actual	2013 Target	Variance
Appointments not met on time (excluding AMI) (number)	22	6	+266%
GSL – New connections not made on or before the date agreed (number)	5	28	-82%
GSL – Low reliability payments (number)	368	144	+155%
GSL – Street Lights (number)	2	54	-96%

9.2.1 APPOINTMENTS NOT MET ON TIME (EXCLUDING AMI)

262. In 2013, 22 appointments were not met on time, compared with a target of six. Two main factors that contributed to this unfavourable result are listed below:

- The target of 6 missed appointments per year was based on historical data in 2005-2009, where missed appointment numbers were at a minimum, and
- In 2010, JEN engaged a new service provider. Immediately after engaging the new provider, an increase in missed appointment GSLs was evident. This was primarily related to the service provider's unfamiliarity with the distribution region. Improvement was shown in the 2011 Relevant Regulatory Year, but missed appointment GSLs again returned a high result. Significant improvement has been seen in 2012 and again in 2013 after more extensive service provider training.

9.2.2 GSL – NEW CONNECTIONS NOT MET ON OR BEFORE THE DATE AGREED

263. With the new service provider commencing in 2010, more stringent timeframes for new connections were applied. A timeframe of two days for single phase sites and four days for multiple and three phase sites was stipulated in the new service contract. These timeframes are well below the required 10 days. As a result, a low number of new connection-related GSLs were evident for 2013.

9.2.3 GSL – LOW RELIABILITY PAYMENTS

264. The low reliability payments were as a result of customers being off supply for either greater than 20 hours or greater than 30 hours. The majority of the low reliability payments were attributable to a significant pole fire event between 27 and 31 January 2013 and a severe windstorm on 1 October 2013.

9.2.4 GSL – STREET LIGHTS

265. In 2013, only two of JEN customers received a GSL payment for street lights that were not repaired in two working days. This out performance is due to improved business systems and processes that were initially introduced in 2010 and fully implemented in 2011.

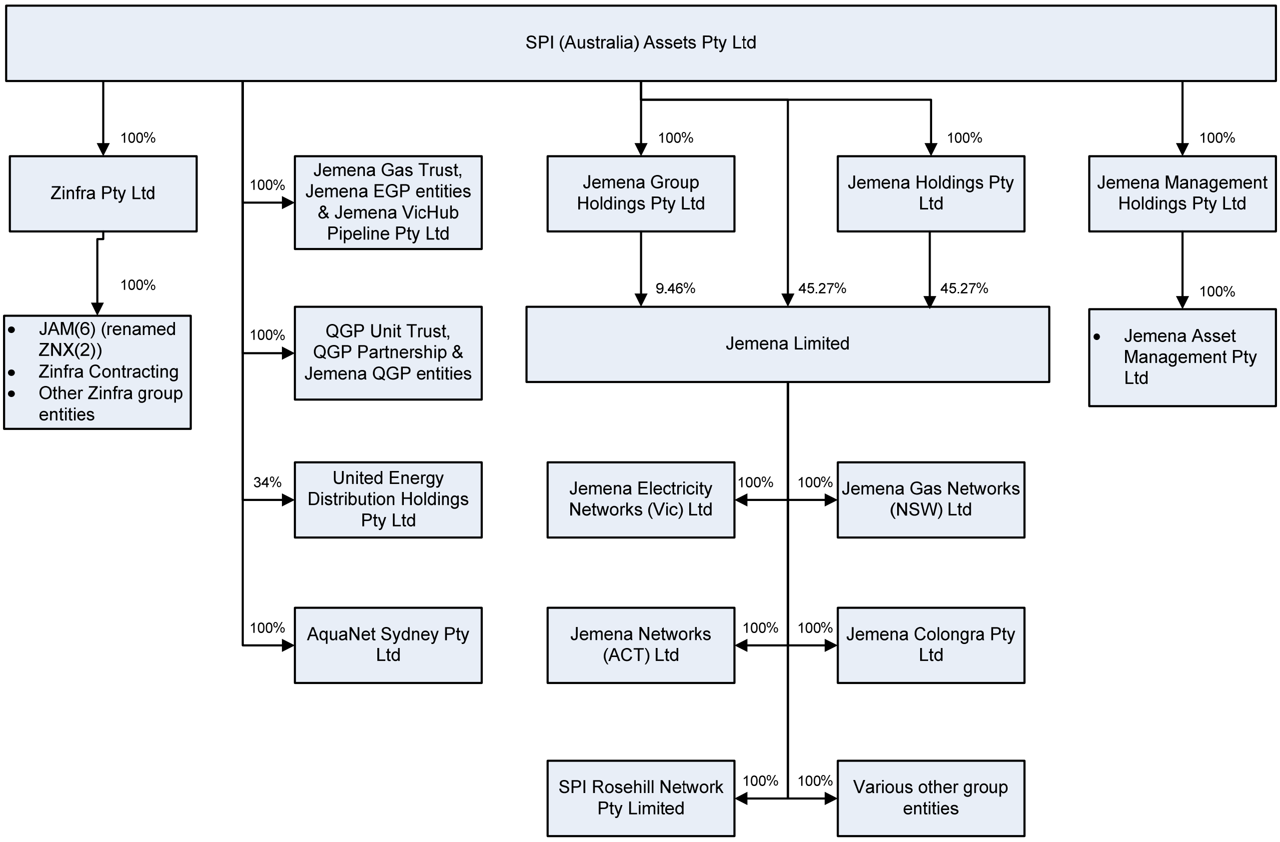
9.3 CHARTS

266. In this section, JEN responds to section 9 of Schedule 1 to the RIN for the 2013 Relevant Regulatory Year.

9.3.1 GROUP CORPORATE STRUCTURE

267. Section 9 of Schedule 1 to the RIN requires JEN to provide a chart showing the group corporate structure which JEN is a part of. The group structure is set out in Figure 1.

Figure 1: Jemena Group structure as at December 2013



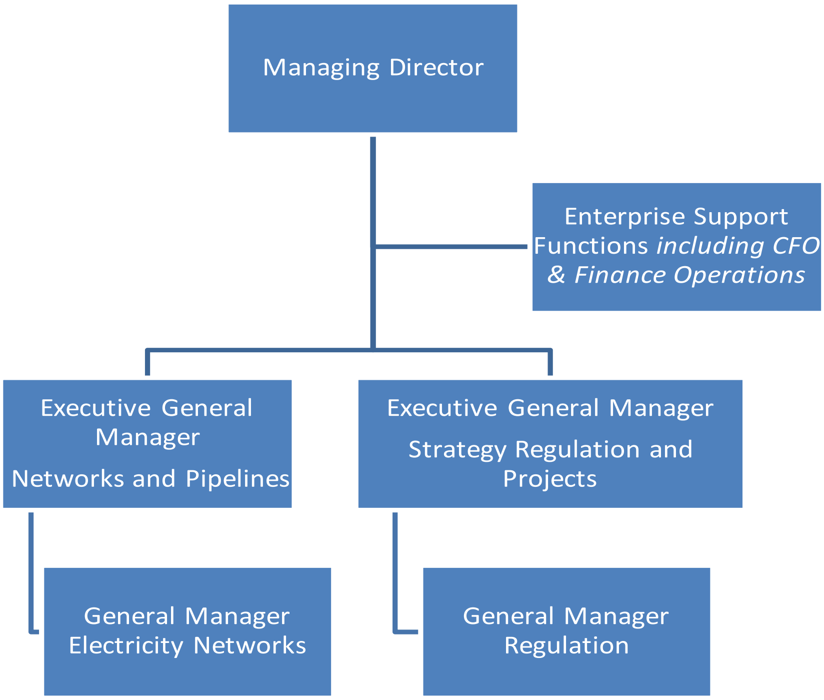
268. As shown in Figure 1, in CY2013 JEN was a 100 per cent owned subsidiary of JEM. JEM was a wholly owned subsidiary of SPIAA, which is in turn 100 per cent owned by Singapore Power International (**SPI**).

9.3.2 JEN ORGANISATIONAL STRUCTURE

269. Section 9 of Schedule 1 to the RIN requires JEN to provide a chart showing the organisational structure of JEN.

270. While JEN owns the electricity network assets, enterprise support services such as legal, finance and human resources are provided to JEN by JEM. As such, the senior management group directing the JEN business entity resides within JEM. JEM's operational structure in relation to JEN is set out in Figure 2.

Figure 2: Jemena Operational Structure as it relates to JEN as at December 2013



271. For 2013 the asset management functions were performed at the JEN/JEM level, with JAM focusing on maintenance and other operational network services.

10. AUDIT REPORTS

272. In this section, JEN responds to section 10 of Schedule 1 to the RIN for the 2012 Relevant Regulatory Year.

10.1 REGULATORY AUDIT REPORTS

273. Section 10.1 of Schedule 1 to the RIN requires JEN to provide a Regulatory Audit Report in the form of:

- a Special Purpose Financial Report; and
- an Audit Report (for non-financial information)
- in accordance with the requirements set out in Appendix E of the RIN, the Regulatory Audit Reports requested are provided in Appendix 1-7 and Appendix 1-8 of JEN's response respectively.

Provision of Regulatory Audit Reports to JEN's management

274. Section 10.2 of Schedule 1 of the RIN requires JEN to provide all reports from the Auditors to JEN's management regarding the audit review and/or auditors' opinions or assessments.

275. JEN provided all reports to the JEN board. An extract of the board minutes is attached in Appendix 1-9 of JEN's response.

11. BOARD RESOLUTION

277. In this section, JEN responds to section 11 of Schedule 1 to the RIN for the 2013 Relevant Regulatory Year.

11.1 EXTRACT FROM BOARD MINUTES

278. Section 11.1 of Schedule 1 of the RIN requires JEN to provide an extract from the board minutes or a resolution agreed to at a JEN board meeting that confirms that, to the best of the board's information, knowledge and belief:

- the information provided in the response to paragraph 1.1(a) (being the information required in Appendix B and attached in Appendix 1-1 of JEN's response) is true and fair, and
- the STPIS and demand information provided in the response to paragraph 1.1(b) (being the information required in Appendix C and attached in Appendix 1-2 of JEN's response) is true and fair.
- JEN has provided an extract from the board minutes in Appendix 1-9 of JEN's response.

12. STATUTORY DECLARATION

279. In this section, JEN responds to page one, paragraph three, point (c) of the RIN for the 2013 Relevant Regulatory Year.

280. Page one, paragraph three, point (c) of the RIN requires JEN to verify, by way of a statutory declaration, the information specified in the RIN submission in accordance with Appendix D of the RIN.

281. JEN has provided the statutory declaration in Appendix 1-10 of JEN's response.

13. APPENDICES

No.	Appendix Title
1-1	RIN template Appendix B – regulatory accounting statement templates
1-2	RIN template Appendix C – non-financial information templates
1-3	Reconciliation between statutory accounts and regulatory accounting statements
1-4	JEN regulatory accounting principles and policies (2013)
1-5	JEN capitalisation policy (2013)
1-6	Cost allocation methodology (2010)
1-7	Special purpose financial report by KPMG
1-8	Audit report (for non-financial information) by PB
1-9	JEN board resolution
1-10	RIN template Appendix D – statutory declaration