AER Final RIN – CITIPOWER Schedule 1 Response

1. REGULATORY ACCOUNTING STATEMENTS & NON-FINANCIAL INFORMATION		
1.1(a)	Provide the Regulatory Accounting Statements, being the information required in the worksheets in the Microsoft Excel workbook attached at Appendix B; as amended by the AER on 6 August 2014;	Please refer to accompanying Appendix B Templates 1a-29.
1.1(b)	Provide the non-financial information required in the worksheets in the Microsoft Excel workbook attached at Appendix C, as amended by the AER on 6 August 2014;	Please refer to accompanying Appendix C Templates 1a-4c.
1.1(c)	Provide a Microsoft Excel workbook that reconciles and explains adjustments between the Statutory Accounts and the Regulatory Accounting Statements. CitiPower must separately list each adjustment to the Statutory Accounts made to derive the Regulatory Accounting Statements, and for each adjustment made: (i) specify the amount of the adjustment (ii) describe the nature and basis of each adjustment	Please refer to “Attachment 1 – 1.1(c) Stat to Reg CitiPower 2015”.
1.1(d)	Provide a Basis of Preparation demonstrating how CitiPower has complied with the Notice, in accordance with this Notice and the Principles and Requirements at Appendix A	Please refer to accompanying Basis of Preparation documents.
1.1(e)	Provide the Regulatory Accounting Principles and Policies and the Capitalisation Policy for the Relevant Regulatory Year.	Please refer to “Attachment 2 – 1.1(e) Regulatory Accounting Principles and Policies CP”.
1.1(f)	Provide a statement of the policy for determining the allocation of overheads in accordance with the approved *Cost Allocation Method* for the Relevant Regulatory Year.	Overhead rates are applied by the SAP system to directly attributable costs for corporate, network, system control and fleet and property labour and service costs which are, in accordance with our statutory accounting policies, attributable to the function of preparing an asset ready for use or of maintaining an asset. The network overhead pool is sourced from costs which

<table>
<tr><td></td><td></td><td>are shared and allocated between CitiPower and Powercor as described in section 11.3 of our Cost Allocation Method.</td></tr>
<tr><td>1.2</td><td>Identify all changes between the Regulatory Accounting Principles and Policies provided in the response to paragraphs 1.1(e). For each change identified:
(a) explain the nature of and the reasons for the change; and
(b) quantify the effect of the change on the Regulatory Accounting Statements for the Relevant Regulatory Year.</td><td>There are no changes between the Regulatory Accounting Principles and Policies provided in response to paragraphs 1.1(e).</td></tr>
<tr><td>1.3</td><td>Identify all changes between the statements of the policy for determining the allocation of overheads in accordance with the approved Cost Allocation Method provided in the response to paragraph 1.1(f). For each change identified:
(a) explain the nature of and the reasons for the change; and
(b) quantify the effect of the change on the Regulatory Accounting Statements for the Relevant Regulatory Year.</td><td>There are no changes between the statement of the policy for determining the allocation of overheads in accordance with our Cost Allocation Method provided in the response to paragraphs 1.1(f).</td></tr>
<tr><td>1.4</td><td>Identify each material difference (where the difference is equal to or greater than ±10%) between the amount reported in the Regulatory Accounting Statements and the amount provided for in the 2011–15 Distribution Determination, for the following:
(a) total actual revenue and total forecast revenue;
(b) total actual operating expenditure and total forecast operating expenditure;
(c) total actual maintenance expenditure and total forecast maintenance expenditure;
(d) total actual capital expenditure and total forecast capital expenditure; and
(e) total actual energy sales and total forecast energy sales.</td><td>(a) The difference between the total actual revenue and total forecast revenue is not material.

(b) The difference between the total actual operating expenditure and total forecast operating expenditure is not material.

(c) The difference between the total actual maintenance expenditure and total forecast maintenance expenditure is not material.

(d) The difference between the total actual capital expenditure and total forecast capital expenditure is as follows:

<table><tr><th>Category</th><th>Variance</th></tr><tr><td>Reinforcements</td><td>(32.7%) / ($16.2M)</td></tr><tr><td>New customer connections</td><td>10.8% / $6.6M</td></tr><tr><td>Reliability & quality maintained</td><td>(56.5%) / ($22.5M)</td></tr></table></td></tr>
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<tr><td></td><td></td><td>
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<tr><td>Environmental, safety & legal</td><td>(4.4%) / ($0.3M)</td></tr>
<tr><td>SCADA network control</td><td>(34.4%) / ($1.0M)</td></tr>
<tr><td>Non-network general assets - IT</td><td>64.4% / $6.6M</td></tr>
<tr><td>Non-network general assets - other</td><td>(87.5%) / ($3.0M)</td></tr>
<tr><td>Customer contributions</td><td>84.9% / $10.5M</td></tr>
<tr><td>TOTAL</td><td>(24.9%) / ($40.3M)</td></tr>
</table>
(e) The difference between total actual demand and total forecast demand is not material.
</td></tr>
<tr><td>1.5</td><td>Explain the reasons underlying the changes in expected operational activities or drivers that caused each material difference identified in the response to paragraph 1.4.</td><td>
<u>Capital expenditure</u>
Reinforcements: Expenditure is less than forecast at the 2011-15 Distribution Determination as a result of:
1. lower than forecast demand in some areas of the network;
2. CBD security upgrade and Metro projects being delayed due to community and local government objections to the planning permit for the Brunswick Terminal Station (BTS) upgrade; and
3. ‘knock-on’ effects to other major projects relying on the establishment of BTS.

New customer connections: economic conditions have continued to improve following the impacts of the global financial crisis resulting in higher connection activity in 2015 than forecast at the 2011-15 Distribution Determination.

Reliability and quality maintained: expenditure is less than forecast at the 2011-15 Distribution Determination as a result of strategies developed to maximise efficiencies between major plant replacements and network augmentations e.g. Prahran (PR) decommissioning strategy.

SCADA network control: expenditure is less than forecast at the 2011-15 Distribution Determination as a result of:
1. efficiencies having been realised for some, but not all, new optic fibre builds by negotiating shared use agreements with other fibre optic cable owners; and
2. as a consequence this has reduced the number of new fibre optic builds
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<td>over the 2011-2015 regulatory control period.

Non-network general assets – IT: over the smart meter roll out period, standard control systems have been maintained rather than enhanced due to the focus on the implementation of smart meter related systems. We re-commenced our investment in these standard control systems over 2015.

Non-network general assets – Other: purchase of new fleet, including a crane borer, and light fleet to support operational requirements and an upgrade of the fleet to address changes in safety and compliance as required by Australian Standards (AS) or Australian Design Rules (ADR) have driven expenditure.

Customer contributions: see new customer connections.</td>
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<td>1.6</td>
<td>Identify each material difference (where the difference is equal to or greater than ±10%) between the target performance measure specified in the service target performance incentive scheme and actual performance reported in the response to paragraph 1.1(b).</td>
<td>We are rewarded or penalised under the service target performance incentive scheme (**STPIS**) which covers our reliability performance and telephone response.

Actual STPIS outcomes versus the AER targets are set out in the table below:

<table>
<tr><th colspan="5">CitiPower - 2015</th></tr>
<tr><th colspan="2">Measure</th><th>AER Target</th><th>Actual</th><th>Variance (%)</th></tr>
<tr><td rowspan="3">CBD</td><td>USAIDI</td><td>11.271</td><td>14.432</td><td>(28)</td></tr>
<tr><td>USAIFI</td><td>0.186</td><td>0.268</td><td>(44)</td></tr>
<tr><td>MAIFI</td><td>0.026</td><td>0.000</td><td>100</td></tr>
<tr><td rowspan="3">Urban</td><td>USAIDI</td><td>22.36</td><td>29.015</td><td>(30)</td></tr>
<tr><td>USAIFI</td><td>0.450</td><td>0.417</td><td>7</td></tr>
<tr><td>MAIFI</td><td>0.175</td><td>0.364</td><td>(108)</td></tr>
<tr><td colspan="2">Telephone Answering (%)</td><td>71.52</td><td>84.46</td><td>13</td></tr>
</table>
</td>
</tr>
<tr>
<td>1.7</td>
<td>Explain the reasons underlying the changes that caused each material difference identified in the response to paragraph 1.6.</td>
<td><u>Reliability</u>
We underperformed against the AER targets for CBD USAIDI (i.e. unplanned SAIDI), CBD USAIFI (i.e. unplanned SAIFI) and urban USAIDI, and MAIFI. The</td>
</tr>
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		main causes for the underperformance in our CBD network related to interruptions caused by equipment failure, interruptions where the cause was unknown and outages caused by a third party such as vehicle impacts. The main causes for under performance in our urban network was interruptions caused by equipment failure, outages caused by a third party such as vehicle impacts and animals shorting out power lines. Telephone answering Our contact centre achieved greater than 10% variance to AER target. Favourable weather conditions and the adoption of alternative digital communication capabilities resulted in a reduction of total annual calls 16% below what was received in the previous year. The unexpected continuation of low call volumes resulted in an increase in annual GOS.
1.8	Where it is not possible to provide the information in Schedule 1 as required by the Notice, provide: (a) An estimate, using best endeavours to generate the most appropriate estimate; and (b) The basis for this estimate, explaining why it is the most appropriate estimate; or (c) If it is not possible to provide an estimate, explain why the information as required by this Notice has not been provided, and why an estimate is not able to be derived.	Please refer to accompanying Basis of Preparation documents.
2. COMPLIANCE		
2.1	Explain the procedures and processes used by CitiPower to ensure that the distribution services have been classified as determined in the 2011-15 Distribution Determination.	Please refer to our Cost Allocation Method and Basis of Preparation documents.
2.2	Explain the procedures and processes used by CitiPower to ensure that the negotiated service criteria, as set out in the 2011-15 Distribution Determination, have been applied.	Negotiated services are customer requests to alter or relocate public lighting assets and customer requests for new public lighting. Customer requests for public lighting services are treated in a similar way to a customer request for supply or to relocate assets. The request is negotiated based on our network policies and all offers to customers are based on standard customer

		agreements in line with the negotiating framework approved by the AER. The timeframes to provide offers are monitored and reported annually to our Risk Management and Compliance Committee and Regulation team.
2.3	Describe the process CitiPower has in place to identify negative change events under clause 6.6.1(f) of the NER and the materiality threshold applied to these events.	We continuously scan for regulatory change events, service standard events, tax change events and retailer insolvency events. If a negative change event occurs, we estimate the resulting incremental standard control service cost saving. If the estimated incremental cost saving is greater than one per cent of annual standard control revenue, we will notify the AER within 90 business days of becoming aware of the occurrence of a negative change event.
3. COST ALLOCATION TO THE REGULATED DISTRIBUTION BUSINESS		
3.1	Identify each Item in the Regulatory Accounting Statements that is: (a) not allocated on a directly attributable basis but is allocated on a causation basis to CitiPower; or (b) not allocated on a directly attributable basis and cannot be allocated on a causation basis to CitiPower.	Please refer to the Cost Allocation Method.
3.2	For each Item identified in the response to paragraphs 3.1(a): (a) state the amount of the item that has been allocated; (b) explain the method of allocation and reasons for choosing that method; and (c) state the numeric amount of the allocator(s) used.	Please refer to the Cost Allocation Method.
3.3	For each Item identified in the response to paragraph 3.1(b): (a) state its amount; (b) state whether it was Material; (c) explain the method of allocation and reasons for choosing that method; and (d) explain the reason(s) why it cannot be allocated on a causation basis.	Please refer to the Cost Allocation Method.

4. COST ALLOCATION TO SERVICE SEGMENTS Note: service segment refers to standard control services, Advanced Metering Infrastructure (AMI), alternative control services, negotiated services and unregulated services.		
4.1	Identify each item in the Regulatory Accounting Statements that is: (a) Not allocated on a directly attributable basis but is allocated on a causation basis from CitiPower to a service segment; and (b) Not allocated on a directly attributable basis and cannot be allocated on a causation basis from CitiPower to a service segment.	Please refer to Appendix B – additional tab “Income Work Paper”.
4.2	For each item identified in the response to paragraph 4.1(a): (a) State the amount of the item that has been allocated; (b) Explain the method of allocation and reasons for choosing that method; and (c) State the numeric amount of allocator(s) used.	Please refer to Appendix B – additional tab “Income Work Paper”.
4.3	For each item identified in the response to paragraph 4.1(b): (a) State its amount; (b) State whether it was Material (c) Explain the method of allocation and reasons for choosing that method (d) Explain the reason(s) why it cannot be allocated on a causation basis.	Please refer to Appendix B – additional tab “Income Work Paper”.
5. RELATED PARTY TRANSACTIONS		
5.1	Identify each Related Party to which a transaction has been conducted.	Please refer to Appendix B – Template 20 “Related party transactions”.
5.2	Identify each transaction relating to the provision of standard control services, alternative control services, AMI or negotiated distribution services between CitiPower and a Related Party, where the transaction amount is greater than five per cent of the relevant total expenditure or revenue category. Relevant	Please refer to Appendix B – Template 20 “Related party transactions”.

	categories are standard control revenues, alternative control revenues, AMI revenues, negotiated distribution services revenues, standard control capex, alternative control capex, AMI capex, standard control operations expenditure, standard control maintenance expenditure, alternative control operations expenditure, alternative control maintenance expenditure AMI operations expenditure, AMI maintenance expenditure, and negotiated distribution services expenditure.	
5.3	For each transaction identified in the response to paragraph 5.2: (a) state the name of the Related Party; (b) identify any other parties involved; (c) explain the nature and purpose of the transaction, including the good(s) or service(s) provided by the Related Party; (d) state the actual costs incurred by the Related Party in providing good(s) or services(s), not including any profit margin or management fee incurred by CitiPower; (e) explain how the actual costs of the good(s) or service(s) incurred was determined; (f) explain how the actual costs of the good(s) or service(s) incurred is reflected in the Regulatory Accounting Statements; (g) identify the Asset Category, Maintenance Cost category or Operating Cost category to which the actual cost(s) is allocated to; and (h) explain the basis upon which the actual costs of the good(s) or service(s) were allocated, as identified in the response to paragraph 5.3(f), and state the quantum of any allocator applied.	Please refer to Appendix B – Template 20 “Related party transactions”.
6. CAPITALISATION POLICY		
6.1	Identify all changes between the Capitalisation Policies provided in the response to paragraph 1.1(e).	There are no changes to the Capitalisation Policy Statements provided in response to paragraph 1.1(e).
6.2	For each change identified in the response to paragraph 6.1:	There are no changes to the Capitalisation Policy Statements provided in

<table>
<tr><td></td><td>(a) state, if any, the financial impact of the change;
(b) state the reasons for the change;
(c) explain the effect of the change, if any, on the actual operating expenditure, actual maintenance expenditure, and actual capital expenditure incurred, in comparison to the forecast operating expenditure, forecast maintenance expenditure and forecast capital expenditure determined in the 2011–15 Distribution Determination during the Relevant Regulatory Year; and
(d) explain the effect of the change, if any, on the actual operating and maintenance expenditure and actual capital expenditure incurred, in comparison to the previous Relevant Regulatory Year.</td><td>response to paragraph 1.1(e).</td></tr>
<tr><td colspan="3">7. DEMAND MANAGEMENT INCENTIVE ALLOWANCE</td></tr>
<tr><td>7.1</td><td>Identify each demand management project or program for which CitiPower seeks approval.</td><td>Two demand management programs have been identified for which we are seeking approval:
• CitiPower residential storage trial
• Storage investment framework design and analysis (SIFDA)</td></tr>
<tr><td>7.2</td><td>For each demand management project or program identified in the response to paragraph 7.1:
(a) explain:
(i) how it complies with the Demand Management Incentive Allowance criteria set out at section 3.1.3 of the demand management incentive scheme;
(ii) its nature and scope;
(iii) its aims and expectations;
(iv) the process by which it was selected, including its business case and consideration of any alternatives;
(v) how it was/is to be implemented;
(vi) its implementation costs; and
(vii) any identifiable benefits that have arisen from it, including any off peak or peak demand reductions.</td><td>A. CitiPower residential storage trial
(a)
i. Residential energy storage systems have the potential to be used for a variety of network and customer benefits. These benefits include aggregated dispatch of the battery units for peak demand management.
The program is:
1. non-network in nature through investing in supply options for customers that reduces peak demand on the upstream network;
2. addresses peak demand management through trialling the use of battery aggregation software platforms to reduce peak network demand;
3. builds knowledge and capability to efficiently deploy residential storage to reduce peak demand on the network;</td></tr>
</table>

	(b) confirm that its associated costs are not: (i) recoverable under any other jurisdictional incentive scheme; (ii)recoverable under any other Commonwealth or State Government scheme; and (iii) included in the forecast capital or operating expenditure approved in the 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination; and (c) explain any assumptions and/or estimates used in the calculation of forgone revenue, demonstrating the reasonableness of those assumptions and/or estimates in calculating forgone revenue, including the reasons for CitiPower's decision to adjust or not to adjust for other factors and the basis for any such adjustments.	4. is non-tariff based; 5. there is no other scheme under which funding can be obtained or provision in the 2011-2015 distribution determination for this activity; 6. program has been treated as operating expenditure. ii. Residential energy storage will be one of the key technologies that impacts future customer demand profiles and the functional requirements of the network of the future. The project involves the deployment of 20 residential battery units with aggregation software in targeted areas within the network. iii. The project aims to better understand the impacts of battery storage to the network and customer including; 1. residential battery potential to support constrained or high solar areas of the network; 2. centralised grid storage benefits vs distributed customer storage benefits; and 3. value of residential demand management control software from a network and customer perspective. iv. In 2015 we assessed the most relevant technologies that will assist in building a 'network of the future'. Residential energy storage was identified as one of the key technologies of the future and an evaluation of potential services, costs, technology and suppliers was undertaken. A number of network locations were assessed for the potential services that residential storage systems could provide. The targeted locations were selected based on AMI voltage profile, high solar PV penetration and customers with suitable properties for the installations. Areas in Northcote, Clifton Hill and Kensington were identified as the preferred network locations for the deployment of residential battery systems. v. A Request for Information (RFI) was issued to the residential storage market to supply suitable residential energy storage solutions that meet the services and technical requirements identified from the future network technology evaluation. A number of proposals were received with different battery manufacturers, configurations and software layers for aggregated dispatch. Supplier selection targeted the

		most technically established and experienced suppliers, whilst also targeting those suppliers most likely to be adopted in high volume by residential customers. Four different residential battery suppliers (20 batteries in total) were chosen for deployment to assess the different battery configurations and impacts. Battery systems were purchased from July-October 2015 with installations commencing in November 2015. All systems will be fully operational in 2016 for a number of dispatch trials. vi. the forecast total procurement and installation cost for the 20 residential battery systems is $500k. The balance of our DMIS will be used to fund these costs. vii. peak demand reductions will be realised through the aggregated dispatch portal that will dispatch residential battery units connected to a single network asset. (b) its associated costs were not: (i) recoverable under any other jurisdictional incentive scheme; (ii) recoverable under any other Commonwealth or State Government scheme; and (iii) included in the forecast capital or operating expenditure approved in the 2011–2015 Distribution Determination or recoverable under any other incentive scheme in that determination. (c) Not applicable --- **B. Storage investment framework design and analysis (SIFDA)** (a) i. SIFDA involved three main development areas for application of energy storage for demand management: • end-user 'off gridding'; • cold thermal energy storage; and • grid level energy storage on the grid. SIFDA is:

		• non-network in nature as it investigates alternative supply options for customers, load shifting and peak curtailment providing alternative means of meeting demand; • addresses peak and more broad based demand management through identifying best cases for the application of thermal storage, off-gridding and network based storage; • it builds knowledge and capability to efficiently deploy demand management solutions relevant to our network; • non-tariff based; • cannot be funded under other schemes and there is no provision in the 2011-2015 Distribution Determination for this activity; and • costs associated with SIFDA were treated as operating expenditure. ii. The scope of SIFDA was to develop new ideas, challenge existing technical solutions and business models through global benchmarking and the study of best in (storage) class countries. For each storage development area above, the scope was to identify: • suitable technologies (pure storage or hybrid with generation); • design, sizing and initial cost estimate; • improvement through complementary solutions (energy efficiency, demand side management etc.); • role of involved stakeholders, regulatory status, revenue sources; and • construction of a full business case for a standard example of each case. Integration of cases and associated value ranges, solutions and decision rules into a decision-helper tool for the network to make decisions in the future for similar cases. iii. Identify the best technical and economical solutions for energy storage demand management cases, assess each solution’s profitability and potential market, provide the network with appropriate tools to assess

		and forecast energy storage projects. iv. Current forecasts are for storage technologies to reduce in cost over the next 5-10 years, with increased storage penetration into the grid to help manage peak load and intermittent/renewable generation. The SIFDA project was picked due to its future network importance and ability to prepare the network for more energy storage demand management opportunities. v. The project was implemented over the period August 2014 to January 2015 and involved engagement of external parties with specific expertise in energy storage. Extensive data was collected from global benchmarks and utilised to determine the most relevant and economical storage cases. vi. Costs for SIFDA were calculated based on hourly rates for internal resources and invoices for external service providers. vii. SIFDA equips us with the knowledge and network case studies for the economical deployment of energy storage for peak shifting and demand management. (b) its associated costs were not: i. recoverable under any other jurisdictional incentive scheme; ii. recoverable under any other Commonwealth or State Government scheme; and iii. included in our forecast capital or operating expenditure allowances in the 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination. (c) Not applicable
7.3	State the total amount of the Demand Management Incentive Allowance spent in the Relevant Regulatory Year and explain how it was calculated Note: Information provided in response to paragraph 7 of schedule 1 to this Notice will constitute the provision of an annual report for the purpose of paragraph 3.1.4.1 of the AER, Demand Management Incentive Scheme- CitiPower, Powercor, Jemena, SP AusNet and United Energy 2011-15: Part A- Demand Management Innovation Allowance, April 2009.	A. Residential Storage Project - $469k ii. residential battery procurement (x20 units); iii. balance of system materials (inverters, PV array, circuit breakers etc.); iv. battery and solar installations; and v. control and aggregation software for demand management.

		B. Storage Investment Framework Design and Analysis (SIFDA) - $0.130M • cost derived from invoices from external service provider.
8. ADVANCED METERING INFRASTRUCTURE		
8.1	Describe each efficiency improvement made to CitiPower's operations directly or indirectly arising from or associated with the roll out of the Advanced Metering Infrastructure. For example: operational cost savings for CitiPower arising from remote meter reading and connection and disconnection of customers' supplies; more efficient outage detection and rectification; improved accuracy of customer billing.	The benefits associated with advanced metering infrastructure include: i. avoided non AMI meter supply cost for new connections and meter replacements - $790,687; ii. avoided non AMI meter supply & installation cost for fault meter replacements - $152,073; iii. avoided non AMI meter replacements resulting from solar installations - $666,610; iv. avoided cost of routine meter testing costs - $360,294; v. avoided cost of routine non AMI meter reading - $934,705; and vi. avoided cost of non AMI special reads - $673,487.
8.2	For each efficiency improvement identified in the response to paragraph 8.1: (a) explain how it arises from or is associated with the roll out of the Advanced Metering Infrastructure; and (b) if quantifiable, state its amount.	The benefits arise in each case for the following reasons: i. meter supply for new connections and meter replacements – accumulation meter supply - the meter supply cost for accumulation meters that would have been supplied if AMI meters hadn't been used; ii. meter supply and installation cost for fault meter replacements – the meter supply and installation cost for meters that would have been replaced under fault conditions iii. time switch replacements – the number of time switches that would have been replaced if new AMI meters hadn't been installed via the rollout. iv. solar meter replacements / meter reconfiguration - the number of manually read interval meters that would have been installed (replacing accumulation meters) for solar installations. Under the AMI Program, existing AMI meters have been reconfigured for solar installations, avoiding the cost of the meter replacement. v. meter testing costs – the costs of testing that would have carried out if AMI meters hadn't been used; vi. meter reading - the avoided cost to manually read type 5 and type 6 meters as a result of meters now being read remotely; and

		vii. special reading - the avoided cost to manually read type 5 and type 6 meters for re-energisation and de-energisation.
9. SAFETY AND BUSHFIRE RELATED EXPENDITURE		
9.1	For each safety and bushfire related expenditure, specify and define the relevant asset category to which it relates.	Please refer to Appendix B Template 22 "Safety and Bushfire Related Expenditure".
9.2	Identify each material difference (where the difference is equal to or greater than ±10%), in relation to the asset categories specified in the response to paragraph 9.1, between: (a) actual and forecast volumes; (b) actual and forecast expenditure; and (c) actual and forecast unit costs.	Please refer to Appendix B Template 22 "Safety and Bushfire Related Expenditure".
9.3	Provide reasons for each material difference (where the difference is equal to or greater than ±10%) identified in the response to paragraph 9.2.	Please refer to Appendix B Template 22 "Safety and Bushfire Related Expenditure".
9.4	Provide reasons for any difference between the actual volumes submitted as part of the Electrical Safety Management Scheme to Energy Safe Victoria and that in the Regulatory Accounting Statements.	We do not have an agreed safety program or associated targets with Energy Safe Victoria (**ESV**) nor did we set annual targets. The CitiPower figures indicated in the Safety Performance report on Victorian Electricity Networks are figures that were supplied to AER for revenue determination purposes only, based on five year average. It is not accurate to report these as agreed targets. We undertake required actions from asset inspection programs and do not have target replacement numbers. It is not appropriate to report specific annual quantities replaced against these numbers, per category, as a measure of our safety performance.
10. SPONSORSHIP AND MARKETING		
10.1	Provide the following information for all advertising/marketing expenditure allocated to the distribution business: A. For expenditure greater than five per cent of the advertising/marketing expenditure allocated to the distribution business: i. Beneficiary	**A. Lunar New Year** **B. Melbourne Open House** **a. For expenditure greater than five per cent of the advertising/marketing expenditure** **A. Lunar New Year**

	ii. Amount iii. Purpose iv. Proportion of the total advertising/marketing expenditure allocated to the distribution business related to: 1)Safety or safety awareness 2)Managing consumer demand 3)Promoting distribution business brand 4)Other v. Description of the activities undertaken by the beneficiary, supported by the expenditure. B. For all advertising/marketing expenditure allocated to the distribution business not reported under 10.1(a), provide: i. List of beneficiaries ii. Total amount iii. Proportion of the expenditure related to: 1)Safety or safety awareness 2)Managing consumer demand 3)Promoting distribution business brand 4)Other	(i) $6,600 (ii) raise awareness of works underway at Waratah Place zone substation (within Chinatown); (iii) promote distribution business brand; (iv) delivery of the Night Lantern Event as part of White Night festivities; **B. Melbourne Open House** (i) $10,500 (ii) promoting operations in the city and heritage of our assets (iii) promoting CitiPower brand (iv) City of Melbourne showcases historic buildings within their area **b. For all advertising/marketing expenditure allocated to the distribution business not reported under 10.1(a)** nil
10.2	For each expenditure item identified in response to paragraph 10.1(a), identify the expenditure item in the statutory accounts from which it is derived.	All of the items listed in 10.1 form part of the Sponsorship account which is included in “Expenses from ordinary activities” in the Statement of Profit or Loss in the Statutory accounts. This item is expanded in Note 2(b) of the accounts. All items are included under the category “Other expenses”.
	11. CHARTS	
11.1	Provide a chart that sets out: (a) the group corporate structure which CitiPower is a part; and (b) the organisational structure of CitiPower.	(a) Please refer to “Attachment 3 – 11.1(a) CP Group Corporate Structure Inc Spark”. (b) Please refer to “Attachment 4 – 11.1(b) CP Executive Management Team Dec 2015”.

12. AUDIT REPORTS		
12.1	Provide an Audit Report/s in the form of: (a) a Special Purpose Financial Report in accordance with the requirements set out at Appendix E; and (b) an Audit Report (for non-financial information) in accordance with the requirements set out at Appendix E.	(a) Please refer to “Attachment 5 - 12.1(a) CitiPower Annual RIN 2015 Deloitte Audit Report (Financial)”. (b) Please refer to “Attachment 6 - 12.1(b) CitiPower Annual RIN 2015 Deloitte Assurance Report (Non-financial)”.
12.2	Provide all reports from the Auditor to CitiPower’s management regarding the audit review and/or auditors’ opinions or assessment.	Please refer to “Attachment 7 – 12.2 Deloitte-Regulatory Report-2015”.
13. CONFIDENTIAL INFORMATION		
13.1	If CitiPower makes a claim for confidentiality over any information provided in accordance with this Notice, CitiPower must: (a) Comply with the requirements of AER’s Confidentiality Guideline, as if it extended and applied to responses to this Notice; (b) Provide, in addition to a confidential version of any information, a version of the information that may be published by the AER.	(a) We have claimed for confidentiality in relation to Appendix B Template 20 Related Party Transactions. Please refer to “Attachment 8 – 13.1 AER Confidentiality Template - 2015 CP&PAL”. (b) Public and confidential versions of the financial templates have been provided to the AER.
13.2	Confirm in writing that CitiPower consents to the AER publically disclosing (including on the AER website) all information provided in accordance with this Notice, except the confidential version of information the subject of a confidentiality claim under paragraph 13.1.	We consent to the AER publically disclosing (including on the AER website) all information provided in accordance with this Notice, except the confidential version of information the subject of a confidentiality claim under paragraph 13.1.