	(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.	
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: (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.	There are no changes to the Capitalisation Policy Statements provided in response to paragraph 1.1(e).
7. DEMAND MANAGEMENT INCENTIVE ALLOWANCE		
7.1	Identify each demand management project or program for which CitiPower seeks approval.	**A. Network Support WMTS 2013/14 Summer** **B. Jacobs Fault Level Mitigation Study Scope #1** **C. Jacobs Fault Level Mitigation Study Scope #2** **D. AEMO Data provision (Supports Jacobs Fault Level Mitigation Study)** **E. Storage Investment Framework Design and Analysis**

7.2	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. (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.	**A. Network Support WMTS 2013/14 Summer** (a) (i) The project was a trial of an inner urban location demand side initiative, which had the effect of deferring capital expenditure. (ii) This was a network support project which involved an existing embedded generator operating 2 x 6MW gas fired generators. A network support agreement was established to enable these generators to provide coincidental capacity support to the Bouverie St zone substation which supplies Carlton, parts of North Melbourne and the northern fringe of the Melbourne CBD. (iii) The aims and expectations of the project were to test the performance, contractual arrangements and support outcomes including operational capability. The project was also initiated to enable deferment of the requirement of an augmentation to transfer load to the BSBQ 66kV supplied system until BTS 66kV supply is available to relieve the constrained WMTS 66kV system. (iv) The process for selection involved consideration of options over a short period of time including demand management, network augmentation and network support. The demand management option was considered against customer requirements in the area and previous experience, and considered that DM at this point would be inflexible and difficult to coordinate. Augmentation in the short term of the 22kV system would be very expensive and transfer to the 66kV not permissible without overloading the 66kV system. This favoured the network support option. (v) The embedded generation owner was engaged by CitiPower via a network support agreement. The agreement was in place for the period of 1st January to 31st March 2014 via 2 x 6MW gas fired generators, already installed and connected to the network from the existing premises. (vi) The implementation costs were $15,000 for contract establishment, followed by $30,000 per month for generation support. Total cost was $105,000 for the period of 1st January to 31st March 2014. (vii) Benefits included learnings from the experience of engaging with an embedded generator for network support including the performance of the local generator from an operational perspective, the time taken to establish an agreement contract as well as the terms and conditions and expected approximate cost for future support; Another benefit is the deferral of the augmentation until BTS is available. (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 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination. (c) As there was no foregone revenue claimed, no calculation of this has been made. **B. Jacobs Fault Level Mitigation Study Scope #1** (a)(i) The project was to explore opportunities within the CitiPower network to examine wider network and transmission solutions to resolve inherent fault level issues within the CBD and permit additional embedded generation connections as potential non-network solutions to existing and forecast capacity constraints. (ii) The project assessed the indicative fault level headroom across the CitiPower distribution network within the Melbourne CBD originating from four terminal stations (FBTS, BTS, RTS, WMTS). An indicative level of generation size that could be permitted at each zone substation was also determined. Network solutions were then explored to increase fault level headroom if a network bus was identified as approaching its fault level limit, to facilitate future additional embedded generation connections. (iii) The aims and expectations of the project were to confirm and receive an independent review of zone substations approaching fault level limit, gain an understanding of existing fault level headroom, determine an indicative level of generation size that could be permitted at each zone substation, and identify any network solutions to increase fault level headroom to facilitate future additional embedded generation connections. (iv) the process for selection involved comparing the capabilities of consultants to do this study. As Jacobs had already completed a similar study in 2011 they were selected. (v) The project was conducted by Jacobs Consulting on behalf of CitiPower. The findings were provided to CitiPower in a project report and presentation. The project occurred throughout 2014. (vi) The project costs were $95,804. (vii) The benefits were to gain a better understanding of the existing transmission imposed network constraints and possible solutions to accommodate future additional embedded generators onto the network to potentially offer non-network solutions to existing and forecast fault level constraints. Details as stated in the aims and expectations above.

		(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 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination. (c) As there was no foregone revenue claimed, no calculation of this has been made. **C. Jacobs Fault Level Mitigation Study Scope #2** (a)(i) The project was to develop a strategy to mitigate fault levels at constrained network locations. The aim was to develop a generic strategy that could be applied to resolve any future fault level constraints on the network to facilitate future additional embedded generation connections as potential non-network solutions to existing and forecast capacity constraints. (ii) The project assessed fault levels at zone substations over the five year outlook period (2015 – 2019), considering load forecasts and network augmentations. Fault level mitigation strategies were then considered for zone substations approaching fault level limit. The preferred options were identified based on technical and economic viability. A high level review of fault mitigation strategies adopted by other distribution businesses was also performed. (iii) The aims and expectations of the project were to identify future fault level issues and establish a fault level mitigation strategy including preferred options to address fault level constraints to accommodate future additional embedded generation connections. (iv) the process for selection involved comparing the capabilities of consultants to do this study. As Jacobs had already completed a similar study in 2011 they were selected. (v) The project was conducted by Jacobs Consulting on behalf of CitiPower. The findings were provided to CitiPower in a project report and presentation. The project occurred throughout 2014. (vi) The project costs were $138,900. (vii) The benefits were to gain a better understanding of future network availability and establish a strategy which recommends preferred distribution

		network solutions to accommodate future additional embedded generators onto the network to potentially offer non-network solutions to existing and forecast capacity constraints. Details as stated in the aims and expectations above. (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 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination. (c) As there was no foregone revenue claimed, no calculation of this has been made. **D. AEMO Data provision (Supports Jacobs Fault Level Mitigation Study)** (a)(i) The transmission system data provision to Jacobs Consulting enabled commencement of scope #1 of their CitiPower Fault Level Mitigation Study. Refer DMIS RIN entry for Jacobs scope #1. (ii) To provide Operations and Planning Data Management System (OPDMS) 1 hour snapshot data to Jacobs Consulting to enable commencement of scope #1 of their CitiPower Fault Level Mitigation Study. Refer DMIS RIN entry for Jacobs scope #1. The OPDMS data contains solved load flow cases which represent the configuration of the transmission system at a point in time, per hour, for the period of 01 July to 30 June 2011. (iii) The aim of the data provision was to enable Jacobs Consulting to commence scope #1 of their CitiPower Fault Level Mitigation Study. Refer DMIS RIN entry for Jacobs scope #1. (iv) AEMO is the only source of the required data. There was no process by which AEMO was selected. (v) Data provision was provided by USB memory card. (vi) The data provision cost $1,900. (vii) The data enabled an accurate study of existing fault level issues based on real time network configuration information. Refer DMIS RIN entry for Jacobs scope #1. (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 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination. (c) As there was no foregone revenue claimed, no calculation of this has been made. **E. Storage Investment Framework Design and Analysis** (a)(i) Storage Investment Framework Design and Analysis involved three main development areas for application of energy storage for demand management: • End-user off gridding • Cold thermal energy storage • Grid Level energy storage on the grid DMIS Criteria numbered and associated responses 1. Non-network in nature through investigating alternative supply options for suitable customers, load shifting and peak curtailment providing alternative means of meeting demand. 2. Program addresses peak demand management and broad-based demand management through identifying best cases for the application of thermal storage, off gridding and network based storage. 3. Builds knowledge and capability to efficiently deploy demand management solutions relevant to the network. 4. Program is non-tariff based. 5. There is no other scheme under which funding can be obtained nor is there provision in the distribution determination for this activity. 6. Expenditure was treated as opex. (ii) New ideas, challenge of existing technical solutions and business models through global benchmark and study of best in (storage) class countries. For each storage development area above, generate: • 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. • 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 significantly reduce in cost in the next 5-10 years, with significantly 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) Project implemented –August 2014 to January 2015, and involved engagement of ENEA Consulting with specific expertise in energy storage. Extensive data collected from global benchmark and utilised to determine most relevant and economical storage cases. Regular meeting and data collection from internal groups for development of first project opportunities for end-user off gridding, cold thermal energy storage and grid level energy storage. (vi) Hourly rates from employees and service providers. Cost derived from invoices from energy storage service provider and proposal cost estimate (vii) The project equips the business with knowledge, network case studies and tools to deploy relevant and economical energy storage for peak shifting and demand management. Trial projects targeted from the SIFDA analysis will target reductions in traditional network demand. (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 2011–15 Distribution Determination or recoverable under any other incentive scheme in that determination. (c) As there was no foregone revenue claimed, no calculation of this has been

		made.
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. Network Support WMTS 2013/14 Summer - $105,000 B. Jacobs Fault Level Mitigation Study Scope #1 - $95,804 C. Jacobs Fault Level Mitigation Study Scope #2 - $138,900 D. AEMO Data provision (Supports Jacobs Fault Level Mitigation Study) - $1,900 Costs are predominantly external contract costs. E. Storage Investment Framework Design and Analysis - $62,326 Costs are derived from invoices from external service provider and proposal cost estimates.
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.	1. Avoided non AMI meter supply cost for new connections and meter replacements - $763,635 2. Avoided non AMI meter supply & installation cost for fault meter replacements - $148,642 3. Avoided non AMI meter replacements resulting from solar installations - $585,830 4. Avoided cost of routine meter testing costs - $251,614 5. Avoided cost of routine non AMI meter reading - $905,975 6. Avoided cost of non AMI special reads - $531,473
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.	1. 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. 2. 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 if new AMI meters hadn't been installed via the rollout. 3. 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.