	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.	
	7. DEMAND MANAGEMENT INCENTIVE ALLOWANCE	
7.1	Identify each demand management project or program for which Powercor seeks approval.	**A. Network Support CTN** **B. Network Support BMH** **C. Greensync pilot of residential DM in the Werribee area.** **D. Demand Management Storage Project** **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	**A. Network Support CTN** **B. Network Support BMH** **C. Greensync pilot of residential DM in the Werribee area.** (a)(i) Projects A and B have the effect of deferring capital expenditure, providing operational and planning learnings and can be redeployed in other locations. Project C endeavoured to provide a business case for Demand Management in a suitable location providing a learning experience of how DM can be justified. (ii) Projects A and B are network support projects which were deployed to inject electrical power into the CTN and BMH 22kV feeder networks in Western Victoria. The projects included 1250kVA and 350kVa portable generators and included supply and lease of equipment, labour and fuel. Project C involved collecting load and customer information to identify areas for possible deployment of DM and analysing the data to provide a justification. (iii) The aims and expectations of the projects were to gain experience and operational capability. The feeders were forecast to possibly have unusually high and unpredictable loading due the ending of the drought conditions in the area. Sudden increases in load had been recorded recently and a hot summer was predicted causing a forecast of possible overloads in these two areas. For project C the aim was to identify the justification process to enable future use of DM to defer capital expenditure. (iv) the process for selection involved consideration of options over a short

	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 Powercor's decision to adjust or not to adjust for other factors and the basis for any such adjustments.	period of time including demand management, network augmentation and network support. Our experience with demand management and augmentation indicated that these would be very difficult to employ for projects A and B given the short time frame prior to summer to deploy. Project C was a trial which would determine timeframes for DM for which areas of network growth with forecast future expenditure were considered. (v) Projects A and B were implemented in January to March 2014 with 2x1250kVA and 2x350kVa portable generators. Remote control techniques and remote monitoring were tested to reduce fuel and labour costs while improving response. Project C was a study and a full trial would have been implemented subsequent to the study if it proved beneficial. (vi) The implementation costs for projects A and B were $43,439 and spent during the summer months. Project C cost $18,500 spent in early 2014. (vii) Benefits of projects A and B included deferral of the augmentation of $139,000 and $1,300,000 for 12 months and more than 24 months. Remote control techniques and remote monitoring was tested to reduce fuel and labour costs while improving response. The deployment and decommissioning time was rapid and set standards and guidelines for future deployments. Project C provided benefits in the form of a possible future project to defer capital expenditure. (b) the 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. (c) as there was no foregone revenue claimed, no calculation of this has been made. **D. Demand Management Storage Project** (a)(i) The purpose of the project is to trial the capability of an embedded grid scale energy storage system (GESS). Grid scale energy storage systems have been identified as one of the key technologies that enable the creation of a network of the future through providing grid support services. These include targeted demand management

		(capital deferral), two way power flows (improving renewable integration capability), reactive power support and voltage stability support. Energy storage systems targeted at peak shifting demand on overloaded areas of the network also align with the Australian Energy Regulators (AER) Demand Management Incentive Scheme (DMIS) funding. DMIS Criteria number and associated responses: 1. Non-network in nature, load shifting and peak curtailment providing alternative means of meeting demand. 2. Program addresses peak demand management—which aim to address specific network constraints by reducing demand on the network at the location and time of the constraint. 3. Through the forecast reduction in battery technology costs grid energy storage is potentially an efficient alternative to traditional network capital investment, the DMSP aims to build CP&PAL capability to build a business case, procure and operate grid energy storage. 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 the DMSP. 6. The DMSP project budget includes both capital investment and operating expenditure. The DMSP project expenditure up to the DMIS allowance will be recovered up front and not rolled into the RAB as part of the next regulatory period; however, the remaining capital expenditure above the DMIS allowance must be recovered and rolled into the RAB. (ii) Given the key grid support services mentioned above, a 2MW grid energy storage system is ideally placed to be deployed on an overloaded and unreliable network feeder to maximise the service values provided. However, an easier deployment solution may be a zone substation where land and communications are already available to monitor this emerging technology. (iii) Network • Identify the application of energy storage services for a range of network constraints, in particular the ability to target peak demand and defer traditional network capital expenditure. • Expand CP & PAL capability for storage integration. Economic • Validate both cost and value of storage services. • Develop a storage system that drives a multitude of economic benefits (i.e. reduced STIPS, capex deferral, potential trading revenues, etc.) • Record and communicate project learnings to optimise future storage

		project scoping and delivery. Technology • Develop CP & PAL capability to perform the operations and maintenance duties of storage systems. • Equip CP & PAL with a breadth of storage technical knowledge to ensure value is maximised from future opportunities. Regulation • Provide real data for regulation of storage technologies. • Demonstrate appropriate safe & environmentally compliant storage applications. (iv) The DMSP project was picked due to its future network importance and ability to maximise the storage values outlined above at a network significant scale. 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. If proven viable the DMSP is suitable for replication across the network for traditional services like peak management and for future services including managing high renewable energy penetrations. With the supporting funding and at very specific constrained locations on the network the DMSP project business case is forecast to be neutral or positive, recouping the high battery costs (forecast to reduce significantly) through traditional capital deferral and outage reductions. (v) Business case development (2014) • Assess and theoretically value grid scale energy storage services. • Review current network constraints and planned capital investments to maximise the value and operation of a grid energy storage system. Project implementation (2014 – 2015) • Procure a 2MW / 2MWh grid energy storage system. • Scope and create project budget for integration of the grid energy storage system into CP & PALs network. • Install grid energy storage system at targeted location within the network to maximise learnings and commercials of the business case. Trial (2015-2017) • Create and optimise safe operational procedures for the control and dispatch of grid energy storage systems on the CP&PAL network. • Trial and assess viability of grid energy storage services including peak demand management and compare the theoretical benefits with the actual

		benefits realised in the field. • Determine opportunities to streamline costs of deployment and operation of network energy storage for future opportunities and applications. • Capture technical learnings for future opportunities and applications. • Prepare traditional network for mass adoption of energy storage technologies in the near future. Beyond Trial • Utilise energy storage system for network support and peak management at constrained locations with the CP&PAL network. (vi) Hourly rates from employees and service providers. • Capital costs from grid energy storage system providers. • Capital construction costs of grid energy storage system implementation from service providers (vii) Greater understanding of network grid energy storage business models, including their application for peak demand reduction and traditional network capital deferral. Create and optimise safe operational procedures for the control and dispatch of embedded grid energy storage systems on the CP&PAL network. Opportunities to streamline costs of deployment and operation of network energy storage for future demand management applications including peak management and intermittent embedded generation. (b) the 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. (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 number 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 CTN - $35,439 B. Network Support BMH - $8,000 C. Greensync pilot of residential DM in the Werribee area - $18,500 D. Demand Management Storage Project - $106,349 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.