

6. DEMAND MANAGEMENT INCENTIVE ALLOWANCE

6.1	Identify each demand management project or program for which Powercor seeks approval.	<ol style="list-style-type: none"> 1. Energy Partner Program—integrate new distributed energy resources (DER) into our demand response program and better engage customers via a platform that will automatically trigger demand response events 2. Dynamic management of HV generation—allows management of minimum demand to reduce future network augmentation, by dynamically managing HV connected generation. <p>These projects are a combined undertaking between CitiPower and Powercor, given we operate the same systems and the programs will benefit customers across both networks.</p>
6.2	<p>For each demand management project or program identified in the response to paragraph 6.1:</p> <p>(a) explain:</p> <ol style="list-style-type: none"> (i) how it complies with the Demand Management Innovation Allowance criteria detailed at section 3.1.3 of the demand management incentive scheme; (ii) its nature and scope; (iii) its aims and expected outcomes; (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; <p>(b) confirm that its associated costs are not:</p> <ol style="list-style-type: none"> (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 2016-20 Distribution Determination or recoverable under any other incentive scheme in that determination; and: <p>(c) state the total amount of the Demand Management Innovation</p>	<p>(a)(i), (ii), (iii), (iv), (v), (vii)</p> <p>1. Energy Partner Program</p> <p>Our previous version of our energy partner program (EPP) worked by offering eligible customers (i.e. those in locations where our network is constrained) a smart device that controls the temperature settings of their air conditioner during scheduled demand response events. By actively controlling the room temperature for a short period during peak demand times, we have reduced peak load for our targeted feeders and thereby deferred augmentation. Customers receive a payment each time they participate in a control event.</p> <p>Following the successful introduction of the EPP, we have extended the program to distribution substations (DSS). Specifically, we have targeted customers with air conditioners who are directly attached to DSS where peak demand is predicted to exceed their maximum capacity.</p> <p>The implementation of the program uses technology and techniques that differ from those previously applied. This includes a new platform that automatically identifies and schedules demand</p>

	<p>Allowance spent in the Relevant Regulatory Year and how this amount has been calculated.</p>	<p>response events using real-time data and forecast weather conditions. The new platform also allows registration of any type of DER that offers demand management capability, regardless of type, manufacturer or communications protocol (i.e. it seeks to address an existing challenge with demand management programs of disparate communications mediums, program interfaces and protocols).</p> <p>Once successful and operating with large enough customer participation, the extension to our EPP will defer or avoid future DSS augmentation by reducing peak demand to levels within the maximum ratings of the assets. The potential benefits of deferred augmentation are material, as we have around 85,000 distribution transformers installed across our networks. As there are fewer customers on a typical DSS than a typical feeder (the target of our existing program) there are more opportunities to defer augmentation as only a few customers per DSS are potentially required to participate in this program.</p> <p>However, given the greater geographical spread of the program, it also means an automated system is needed plus thus this gives great repeatability and flexibility for future demand management uses. We issued a tender and selected a vendor (mPrest) to deliver this automation.</p> <p>We began this update in the first half of 2020 and completed it in December 2020 in time for the 2020/21 summer period.</p> <p>The aim of our extension to the EPP is to defer (or avoid) future DSS augmentation by reducing peak demand to levels within the maximum ratings of the assets.</p> <p>This program has introduced new software applications that enhance the customer experience and seek to automate the communications and connectivity of customers' appliances. This</p>
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6.3	<p>Provide an overview of developments in relation to projects or programs completed in previous years of the regulatory control period, and of any results to date.</p> <p>Note: Information provided in response to paragraph 6 of Schedule 1 to this Notice will constitute the provision of an annual report for the purposes of paragraph 3.1.4.1 of the Demand Management Incentive Scheme applying to Powercor (as set out in the 2016-20 Distribution Determination)</p>	<p>An early version of the Energy Partner demand response program was run last year. This concept has been enhanced as per the description in 6.2.</p>