2016–2020 Price Reset

Appendix F
Base year adjustments

April 2015

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Powercor
2016–2020 Price Reset
Base year adjustments

1 Overview

This appendix provides additional information on adjustments to our base year operating expenditure. These adjustments, as set out in chapter 10 of our regulatory proposal, reflect two categories of expenditure:

- expenditure for which our base year does not reflect the expected costs of these activities going forward; and
- expenditure related to the reclassification of services, for which the impact on consumers is net present value neutral.

Our forecast of these adjustments is set out in table 1 and table 2, and is discussed in detail below.

Table 1 Net adjustments to base year operating expenditure ($m, 2015)

Base year activity	2016–2020
Price reset	-2.0
Guaranteed Service Level payments	0.6
Superannuation (defined benefit scheme)	11.7
Demand Management Innovation Allowance	1.8
Debt raising costs	21.3
Total	**33.4**

Source: Powercor.
Notes: Totals may not add due to rounding.

Table 2 Reclassification of services ($m, 2015)

Reclassification	2016–2020
Supply abolishment	3.0
Category RIN alignment	15.6
IT metering expenditure	24.6
Total	**43.2**

Source: Powercor.
Notes: Totals may not add due to rounding.

2 Base year adjustments

This section discusses expenditure for which our base year does not reflect the expected costs of these activities going forward. Our actual costs for these activities are removed from our base year expenditure, and replaced by a forecast for the 2016–2020 regulatory control period using the approaches set out below.

2.1 Price reset

We incur costs throughout the regulatory control period as a result of our business-as-usual regulatory activity. These activities include, for example, engaging with the Australian Energy Regulator (**AER**), stakeholders, and other government authorities such as the Australian Energy Market Commission (**AEMC**).

We also incur costs during the regulatory control period associated with the preparation of our regulatory proposal. These costs are greater during our base year (relative to an average of the entire regulatory control period). Our actual reset specific costs incurred in 2014 are removed from our base year and replaced by a forecast of regulatory reset costs for the 2016–2020 regulatory control period (as set out in the attached model, *PAL Opex Consolidation*).

Table 3 shows the net adjustment for each year of the 2016–2020 regulatory control period. This approach provides a more accurate reflection of our recurrent base year expenditure.

Table 3 Price reset ($m, 2015)

Price reset	2016	2017	2018	2019	2020	Total
Less: regulatory reset costs	-1.1	-1.1	-1.1	-1.1	-1.1	-5.7
Add: regulatory reset costs	-	-	0.9	1.3	1.4	3.6
Net adjustment	-1.1	-1.1	-0.2	0.2	0.3	-2.0

Source: Powercor.
Notes: Totals may not add due to rounding.

2.2 Guaranteed service level payments

We are required to make guaranteed service level (**GSL**) payments to customers who experience reliability that is worse than specified performance thresholds. These payments may exhibit significant volatility across years based on a range of exogenous factors. Given this variability, actual GSL payments for 2014 are removed from our base year expenditure, and replaced by a forecast reflecting the average of GSL payments over the period 2011–2014 (adjusted for forecast customer growth).[1] This approach is consistent with that adopted by the AER in previous regulatory decisions.

Table 4 shows the net adjustment for each year of the 2016–2020 regulatory control period. This approach provides a more accurate reflection of our recurrent base year expenditure.

[1] Our forecast approach is set out in the attached model, *PAL GSL Step Change*.

Table 4 GSL payments ($m, 2015)

GSL payments	2016	2017	2018	2019	2020	Total
Less: GSL payments	-2.2	-2.2	-2.2	-2.2	-2.2	-11.0
Add: GSL payments	2.2	2.3	2.3	2.4	2.4	11.6
Net adjustment	0.0	0.1	0.1	0.2	0.2	0.6

Source: Powercor.
Notes: Totals may not add due to rounding.

2.3 Superannuation (defined benefit scheme)

In accordance with our legal obligations, we incur superannuation costs on behalf of each of our employees. This includes costs for our defined benefit superannuation scheme.[2]

A defined benefit superannuation scheme is where the employer pays an employee a set amount on retirement, typically based on the employees earnings history. The benefit, or the formula used to determine the benefit, is defined in advance. The employer, therefore, bears any investment risk. Further, under a defined benefit superannuation scheme, the employer's liability may continue even after an employee leaves the organisation.

Our defined benefit superannuation scheme costs reflect the net position of the scheme's defined benefit obligations relative to its defined benefit assets. These costs, therefore, are driven by a range of factors that are largely beyond our control. This includes the state of the global and domestic economies, interest rates, and market returns more generally. For this reason, our defined benefit costs are excluded from our Efficiency Benefit Sharing Scheme (**EBSS**) calculations.

Given the above, our actual defined benefit superannuation scheme costs are removed from our base year operating expenditure, and replaced by a forecast of costs for the 2016–2020 regulatory control period. This approach provides a more accurate reflection of our recurrent base year expenditure.

On an annual basis, we engage the actuary of our superannuation fund, Mercer, to calculate the defined benefit superannuation scheme costs we recognise in our statutory accounts. For the purpose of developing our regulatory proposal, therefore, Mercer also forecast these defined benefit costs for each year of the 2016–2020 regulatory control period.

Mercer developed their forecast under Australian Accounting Standard AASB 119. Mercer's forecasts have regard to assumed investment returns, contributions, benefit accruals, benefit payments, and other expense assumptions.[3] These assumptions reflect Mercer's views as an independent, expert actuary.[4]

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2 Our defined benefit scheme is now closed to new members.

3 Mercer, *Equipsuper—CitiPower and Powercor, Estimated defined benefit cost and net defined benefit asset/liability under AASB 119*, 30 March 2015.

4 Mercer's forecast also reflects an expected decline in the number of defined benefit superannuation scheme members within our organisation over the 2016–2020 regulatory control period. This is expected, as our defined benefit scheme members represent an older demographic, and the scheme is closed to new members. As set out in appendix G, however, this necessitates an offsetting step change for 'replacement' employees.

For the following reasons, our forecast defined benefit superannuation costs reflect those a prudent operator would require to achieve the operating expenditure objectives:

- our defined benefit obligations must be fully funded. This expenditure, therefore, is consistent with the operating expenditure objectives set out in the Rules—for example, the expenditure required to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;[5]
- the magnitude of the increase in our defined benefit superannuation costs is material, and cannot be funded by other elements of our total operating expenditure allowance. For example:
  - the proposed adjustment reflects our net costs;
  - the AER's benchmarking analysis indicates that at a total operating expenditure level, we are in the top quartile of distributors.[6] As our costs are already efficient, absorbing future prudent and efficient cost increases would not reflect the efficient and prudent costs, or a realistic expectation of the cost inputs, required to achieve the operating expenditure objectives;[7] and
- as discussed in chapters 5 and 10, our total operating costs are efficient. These efficient costs have been achieved based on the same forecasting approach adopted for the 2016–2020 regulatory control period. Contrary to the AER's position in its recent Draft Decision for the NSW distributors, forecasting different expenditure categories using alternative approaches will not necessarily lead to a systematically biased forecast of our total operating expenditure.[8]

Table 5 shows the net adjustment for each year of the 2016–2020 regulatory control period.[9]

Table 5 Superannuation ($m, 2015)

Superannuation (defined benefits)	2016	2017	2018	2019	2020	Total
Less: superannuation	-4.3	-4.3	-4.3	-4.3	-4.3	-21.6
Add: superannuation	7.2	6.9	6.7	6.4	6.0	33.2
Net adjustment	2.9	2.6	2.4	2.1	1.7	11.7

Source: Powercor.
Notes: Totals may not add due to rounding.

2.4 Demand management incentive allowance

The National Electricity Rules (**Rules**) allow the AER to develop a demand management incentive scheme to facilitate the investigation and implementation of demand management strategies. Under this scheme, projects and programs may be eligible for a demand management incentive allowance (**DMIA**).

5 NER, cl. 6.5.6(a)(2).

6 Refer to chapter five of our regulatory proposal.

7 NER, cl. 6.5.6(c).

8 See, for example: AER, *Draft decision, Ausgrid distribution determination 2014–19, Attachment 7: Operating expenditure*, October 2014, p. 7–173.

9 For clarity, we have converted Mercer's superannuation forecast into $2015. See: Mercer, *Equipsuper—CitiPower and Powercor, Estimated defined benefit cost and net defined benefit asset/liability under AASB 119*, 30 March 2015, p. 3.

The DMIA is allocated on an annual basis, but the corresponding expenditure is not required to match this profile. For example, the entire allowance for the regulatory control period may be spent during the base year, or alternatively none of the allowance spent. Our actual DMIA expenditure is removed from the base year, therefore, and replaced by a forecast reflecting the expected DMIA across the 2016–2020 regulatory control period. This approach provides a more accurate reflection of our recurrent base year expenditure.

Table 6 shows the net adjustment for each year of the 2016–2020 regulatory control period.

Table 6 DMIA ($m, 2015)

DMIA	2016	2017	2018	2019	2020	Total
Less: DMIA	-0.2	-0.2	-0.2	-0.2	-0.2	-1.2
Add: DMIA	0.6	0.6	0.6	0.6	0.6	3.0
Net adjustment	0.4	0.4	0.4	0.4	0.4	1.8

Source: Powercor.
Notes: Totals may not add due to rounding.

2.5 Debt raising costs

Debt raising costs reflect expenditure incurred when raising new debt, or when refinancing existing debt. The AER calculates debt raising costs based on a benchmark and the volume of debt expected to be raised during the regulatory control period. As set out below, our approach to forecasting debt raising costs differs from that previously adopted by the AER.

2.5.1 Approach to forecasting debt raising costs

We engaged Incenta Economic Consulting (**Incenta**) to develop a forecast of debt raising costs for the 2016–2020 regulatory control period. As set out in the attached report, *Powercor: Debt raising transaction costs*, Incenta's forecast comprises the following three components:[10]

- the cost of issuing the bonds based on an assumed debt portfolio;
- the cost to establish and maintain bank facilities required to meet liquidity requirements for maintaining an investment grade credit rating; and
- the costs to refinance debt three months ahead of the refinancing date (again as a condition of maintaining an investment grade credit rating).

Based on these components, and on our regulatory asset base (**RAB**), Incenta estimated total debt raising transaction costs of 19.6 basis points per annum. This equates to $22.5 million over the 2016–2020 regulatory control period.

2.5.2 Adjustment for debt raising costs

Notwithstanding our different approach to forecasting debt raising costs, the implementation of our approach is consistent with that previously adopted by the AER. That is, our actual debt raising costs incurred in 2014 are removed from our base year, and an allowance for debt raising costs for the 2016–2020 regulatory control period is calculated in the AER's post-tax revenue model (**PTRM**).

[10] Incenta, *Debt raising transaction costs, Powercor*, April 2015.

Table 7 shows the net impact of our implementation approach for each year of the 2016–2020 regulatory control period.

Table 7 Debt raising costs ($m, 2015)

Debt raising costs	2016	2017	2018	2019	2020	Total
Less: debt raising costs	-0.2	-0.2	-0.2	-0.2	-0.2	-1.2
Add: debt raising costs	4.0	4.2	4.5	4.8	5.0	22.5
Net adjustment	3.7	4.0	4.3	4.5	4.8	21.3

Source: Powercor.
Notes: Totals may not add due to rounding.

3 Reclassification of services

This section discusses expenditure related to the reclassification of services, for which the impact on consumers is net present value neutral.

3.1 Supply abolishment

In some circumstances, the electricity supply at a given property may become redundant. The disused service may represent a potential community safety hazard, and hence, supply abolishment is required.

Routine supply abolishments below 100 amps are currently classified as an alternative control service. Charging a fee for this service, however, creates a disincentive for customers to report to the distributor that a disused service is a potential community safety hazard (and abolishment is required). The AER's Framework and Approach paper acknowledged this disincentive, and the corresponding safety risk.[11] For this reason, the AER reclassified supply abolishment below 100 amps as standard control.

Table 8 shows the forecast impact of reclassifying supply abolishments over the 2016–2020 regulatory control period. This forecast reflects the corresponding expenditure incurred during our base year. Supply abolishments have now been removed as an alternative control service.

Table 8 Supply abolishment—adjustment to standard control services ($m, 2015)

Base year adjustment	2016	2017	2018	2019	2020	Total
Supply abolishment	0.6	0.6	0.6	0.6	0.6	3.0

Source: Powercor.
Notes: Totals may not add due to rounding.

3.2 Category RIN alignment

We currently capitalise the following replacement costs in our regulatory accounts—pole treatment costs, bird covers, fuses and surge diverters. In the category analysis RIN, however, the AER considers these services should be reported as operating expenditure.[12] We propose to align the accounting of these costs to be consistent with the category analysis RIN.

The AER's recent Draft Decisions for the NSW and ACT electricity distribution businesses used benchmarking analysis to determine efficient base year operating expenditure. This resulted in reductions to operating expenditure forecasts of up to 41 per cent. The magnitude of these reductions highlights the importance of aligning accounting treatments across distributors to enable valid comparisons to be made.

The AER's Expenditure Forecast Assessment Guideline also acknowledged that nationally consistent data will facilitate the development of more sophisticated benchmarking techniques and other expenditure forecast assessment techniques.[13] Consistent reporting of information across

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11 AER, *Final Framework and approach for the Victorian Electricity Distributors*, 24 October 2014, p. 43.

12 See, for example, the definition in the category analysis RIN for 'pole top, overhead line and services line maintenance', and the requirements in the corresponding RIN template 2.8.

13 AER, *Expenditure forecast assessment guideline*, November 2013, p. 12.

distributors is also important given the expectation that we will be able to explain differences in unit costs relative to our peers.[14]

Table 9 shows the forecast impact of the category RIN alignment over the 2016–2020 regulatory control period. This forecast reflects the corresponding expenditure incurred during our base year.

Table 9 Category RIN alignment—adjustment to operating expenditure ($m, 2015)

Base year adjustment	2016	2017	2018	2019	2020	Total
Category RIN alignment	3.1	3.1	3.1	3.1	3.1	15.6

Source: Powercor.
Notes: Totals may not add due to rounding.

3.3 IT metering expenditure

To implement the Victorian Government's mandated rollout of Advanced Metering Infrastructure (**AMI**) across our network we undertook a complete transformation of our IT infrastructure and systems that support metering, billing and market interactions, including introducing new systems and modifying existing systems.[15] The IT transformation was necessary to manage the vast increase in the volume and speed of AMI data that needed to be received and processed in our IT systems. For example, as a result of the AMI rollout the volume of meter reads per customer per annum has increased from 4 to 17,000. The new and upgraded IT systems replaced some of our pre-existing IT systems that were also used for providing standard control services.

During the 2011–2015 regulatory control period we recovered a portion of the operating costs associated with the new and upgraded IT systems in accordance with the Advanced Metering Infrastructure Order in Council (**AMI OIC**).[16] Accordingly, in the 2014 base year, a proportion of the operating expenditure associated with operating and maintaining the following IT systems was recovered under the AMI OIC:

- Itron Enterprise Edition (**IEE**)—a platform for data collection, validation, storage and processing;
- Itron Market Transaction System (**MTS**)—manages data communication with external market parties, for example providing consumption and billing data to retailers and the wholesale market transaction system;
- Ventyx Service Suite—system used for the scheduling, dispatching, resourcing and tracking the status of field work;
- data warehousing and analytics systems, including SAS—a statistical forecasting program, SAP—used for business intelligence reporting and our data warehousing platform used for the storage of large volumes of data;
- UtilityIQ—the network management system that supports our metering communications network and provides services such as device management, device health monitoring, remote firmware upgrades and outage detection; and

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14 AER, *Expenditure forecast assessment guideline*, November 2013, p. 188.

15 Refer to Powercor's Budget Application 2012—2015 for more information on our investment in new IT systems.

16 Refer to AMI OIC, S2.4 Annexure: Information technology applications, systems and infrastructure.

- Oracle Utility Services Bus (**USB**)—orchestrates business process logic required to perform trans-system functions and facilitates communications across all the different IT systems and programs by enabling the different infrastructures to communicate effectively with each other and thereby utilise the same information.

Operating and maintenance expenditure associated with the above IT systems relates to:

- external vendor charges for licencing fees and software and hardware support, known as support and maintenance costs; and

- labour costs associated with maintaining the systems, for example undertaking day to day operational support activities, system testing, back-ups, installing upgrades, response to user-based service calls, management of capacity, and ensuring operational performance and stability.

Over time AMI sourced data has become increasingly utilised across the business, as it replaced previous accumulation metering data, becoming a core aspect of general operations, including network management and back-office processes. While many of our IT systems originally required upgrading or replacement to facilitate the AMI rollout, these systems are now, with the completion of the AMI roll out, predominately used to deliver standard control services.

Whether or not we own or operate the metering assets, we still need to operate and maintain our IT systems in order to continue to deliver standard control services. As the local distributor we are responsible for receiving and managing metering data to provide billing services for customers in our network area. We also utilise and process the AMI data throughout our IT systems to drive efficiencies in the operation of the network and improve supply reliability for our customers. We will continue to require our IT systems to receive and process AMI data, irrespective of whether the data was originally sourced from our AMI meters or via an external party.

For the purposes of the 2016–2020 regulatory control period, we have therefore examined the appropriate allocation of our 2014 base year IT operating expenditure between standard control services and metering services. For each of the above IT systems or programs we have considered its current and forecast use and, where possible, quantified the proportion of the system used for metering services versus standard control services. Our approach is consistent with the Rules and the AER's *Cost Allocation Guidelines*.[17]

We commissioned Ernst and Young to review our proposed re-classification of IT operating expenditure from metering to standard control services. Ernst and Young found our allocation to be consistent with the AER's *Cost Allocation Guideline*s and our approved Cost Allocation Methodology.[18] Ernst and Young's report *CitiPower and Powercor Australia, Allocation of IT System Operating Expenditure* is attached.

3.3.1 MTS and IEE

MTS is our market gateway, it is responsible for managing seven critical business to business transaction types. These transactions facilitate market relationships and communications between us and third parties, for example retailers. We have examined the proportion of work orders

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[17] AER, *Electricity distribution network service providers, Cost allocation guidelines*, June 2008.

[18] Ernst and Young, *CitiPower and Powercor Australia, Allocation of IT System Operating Expenditure*, April 2015, p.2.

through MTS that could be classified as metering related over the period 1 April 2014 to 1 April 2015. Based on this we estimate that approximately 2.4 per cent of MTS work orders are metering related. Given that the proportion of MTS work orders relating to metering is immaterial, we propose that the 2014 operating expenditure relating to MTS be re-classified from metering to standard control services.

IEE is a data storage, validation and processing system. IEE sends data to other IT systems, predominately MTS and the CIS billing system, to enable those systems to undertake their respective functions. As IEE does not undertake work orders itself, we cannot directly calculate the use of the system for standard control services versus metering services. We consider however that the proportion of MTS work orders attributable to metering is the upper bound on the use of IEE attributable to metering services. This is because IEE also sends data to other systems, in particular the billing system which is solely attributable to standard control services. Given the estimated proportion of MTS used for metering related services is immaterial, we propose that 2014 operating expenditure relating to IEE be re-classified from metering services to standard control services.

Further, whether or not we own or operate the metering assets, we would still require the IEE and MTS systems to be of the same size, capacity and capability to support our distributor responsibilities. There would be no reduction in the level of operating expenditure incurred for these systems if we were to operate the distribution network as a standalone service. For example, the vendors system support and maintenance charges are fixed, such that the charges do not vary with transaction volumes.

3.3.2 Ventyx service suite

The Ventyx service suite system provides field service work orders for both metering related and network related field operations, such as fault response. While Ventyx was originally implemented to support our AMI rollout, over time its use for AMI rollout has declined and the system has been increasingly utilised for network fault management.

In 2014, 23 per cent of Ventyx service suite work orders related to metering services and there were approximately four meters installed for every work order. Using this information and our forecast volume of meter installations, we forecast the proportion of service suite work orders attributable to metering services over the 2016–2020 regulatory control period, as set out in table 10.

Table 10 Forecast proportion of service suite work orders attributable to metering services

	2016	2017	2018	2019	2020
Proportion of work orders (%)	18.7	3.6	3.6	3.6	3.5

Source: Powercor.
Notes: Totals may not add due to rounding.

We consider that the forecast proportion of metering related service suite work orders that will occur during the 2016–2020 regulatory control period to be immaterial. Further, if we did not undertake any metering related field work, we would still require a service suite system to electronically communicate field service work orders for network fault response. Additionally, there would be no reduction in the level of operating expenditure we incur if the service suite system processed fewer work orders. For example, the vendor's system support and maintenance charges are fixed, such that the charges do not vary with transaction volumes.

We therefore propose that 2014 operating expenditure associated with the Ventyx service suite system be re-classified from metering services to standard control services.

3.3.3 Data warehousing and analytics systems

Our data warehousing and analytics systems enable us to process large volumes of data. While these systems were required to facilitate the management of the large volume of AMI data, they are now used solely for the purpose of standard control services. The SAS statistical system is used solely for distribution tariff analysis and development. The SAP Business Intelligence reporting system is used for network management reporting, this included the AMI program but only up until completion of the rollout. The data warehouse is a place for storing meter data for network management and reporting purposes. Accordingly, all of these systems and programs would still be required if we did not own or operate the metering fleet and no reduction in operating expenditure would be incurred.

We therefore propose that 2014 operating expenditure associated with our data warehousing and analytics systems be re-classified from metering services to standard control services.

3.3.4 UtilityIQ

The UtilityIQ system is primarily used for the management of our meshed smart meter communications systems. While UtilityIQ is also used to provide standard control services, such as outage detection, it would not necessarily be required for the provision of standard control services if provided independently of metering services. We therefore do not propose any re-classification of 2014 operating expenditure associated with UtilityIQ from metering to standard control services.

3.3.5 USB

The USB is used to orchestrate business process logic and facilitate communications across all of our different IT systems and programs. To quantify the use of the USB for metering related services we have calculated the proportion of total USB transactions that are incurred with UtilityIQ system. As the USB only holds 35 days of historical data we have undertaken this calculation during the month of March 2015. Of the total 638.7 million USB transactions that occurred in March 2015, 3.5 million of these were with the UtilityIQ system. We therefore estimated the proportion of the USB used for metering related services to be 0.54 per cent.

As the proportion of the USB used for metering related services is immaterial, we propose re-classifying all 2014 operating expenditure from metering services to standard control services. Further, if we did not own or operate the metering fleet we would still require the USB to provide communications across all of our other IT systems used for standard control services, and there would be no reduction in the level of operating expenditure required to operate and maintain the USB.

3.3.6 Total IT operating expenditure transferred from metering to standard control services

Table 11 shows the forecast impact of reclassifying IT metering operating expenditure over the 2016–2020 regulatory control period. This forecast reflects the increase in standard control services base year operating expenditure and the corresponding decrease in metering services base year operating expenditure.

Table 11 IT metering expenditure—adjustment to standard control services ($m, 2015)

Base year adjustment	2016	2017	2018	2019	2020	Total
IT metering expenditure	4.9	4.9	4.9	4.9	4.9	24.6

Source: Powercor.
Notes: Totals may not add due to rounding.