



# **DRAFT DECISION**

## **Advanced metering infrastructure**

## **Transition Charges Applications**

September 2016

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# Contents

## Table of Contents

Contents .....	2
Shortened forms .....	4
<b>1 Summary .....</b>	<b>5</b>
<b>2 Background.....</b>	<b>9</b>
<b>3 Assessment approach .....</b>	<b>12</b>
<b>3.1 Calculation of transition charge .....</b>	<b>12</b>
3.1.1 Revenue and costs true-up.....	12
3.1.2 Metering asset base true-up .....	13
<b>3.2 Assessment of 2014 and 2015 costs.....</b>	<b>13</b>
3.2.1 Scope test .....	14
3.2.2 Prudency test .....	14
3.2.3 Benchmarking .....	15
<b>4 AusNet Services .....</b>	<b>18</b>
<b>4.1 Draft decision.....</b>	<b>18</b>
4.1.1 Revenue and costs true-up.....	18
4.1.2 MAB true-up .....	21
<b>4.2 Reasons for draft decision.....</b>	<b>23</b>
4.2.1 Expenditure excess.....	23
4.2.2 Excess capital expenditure.....	23
4.2.3 Excess operating expenditure .....	32
<b>5 United Energy .....</b>	<b>35</b>
<b>5.1 Draft decision.....</b>	<b>35</b>
5.1.1 Revenue and costs true-up.....	35

5.1.2	MAB true-up .....	37
<b>5.2</b>	<b>Reasons for draft decision.....</b>	<b>39</b>
5.2.1	Excess capital expenditure.....	39
<b>6</b>	<b>Jemena .....</b>	<b>42</b>
<b>6.1</b>	<b>Draft decision .....</b>	<b>42</b>
6.1.1	Revenue and costs true-up.....	42
6.1.2	MAB true-up .....	44
<b>6.2</b>	<b>Reasons for draft decision.....</b>	<b>46</b>
6.2.1	Excess capital expenditure.....	46
6.2.2	Excess operating expenditure .....	49
<b>7</b>	<b>CitiPower .....</b>	<b>51</b>
<b>7.1</b>	<b>Draft decision .....</b>	<b>51</b>
7.1.1	Revenue and costs true-up.....	51
7.1.2	MAB true-up .....	53
<b>8</b>	<b>Powercor .....</b>	<b>56</b>
<b>8.1</b>	<b>Draft decision .....</b>	<b>56</b>
8.1.1	Revenue and costs true-up.....	56
8.1.2	MAB true-up .....	58
<b>9</b>	<b>Benchmarking.....</b>	<b>61</b>
<b>9.1</b>	<b>Review approach .....</b>	<b>61</b>
<b>9.2</b>	<b>Category level benchmarking.....</b>	<b>61</b>
<b>9.3</b>	<b>Sub-category level benchmarking.....</b>	<b>61</b>
9.3.1	United Energy .....	62
9.3.2	Jemena .....	62
9.3.3	AusNet Services.....	63

# Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
capex	capital expenditure
CPI	consumer price index
DRP	debt risk premium
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for Electricity Distribution
F&A	framework and approach
MAB	metering asset base
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RFM	roll forward model
RIN	regulatory information notice

# 1 Summary

On 31 May 2016 we received AMI transition charge applications from all five Victorian electricity distribution businesses.

These applications were submitted in accordance with the Victorian Government's AMI Cost Recovery Order in Council (Order).<sup>1 2</sup> They follow on from the completion of the AMI roll-out period which ran from 1 January 2009 to 31 December 2015. This is the last task the AER is required to do under the Order.

A transition charge (if applied) is an amount that may allow a distributor to recover from the consumer AMI costs that it has not already recovered to date. Alternatively, a distributor may be required to return an amount to consumers if it has recovered costs for AMI that exceed the costs provided for under the Order.

The transition charge amount is determined under the Order by:

- (a) applying a 'true up' of 2009–15 costs and revenues that corrects for the difference between:
  - the AMI costs over the 2009–15 period as approved by us in previous decisions<sup>3</sup> for each distributor
  - the distributor's actual revenues from AMI metering charges;<sup>4</sup> and
- (b) incorporating any 'excess' expenditure incurred in 2014 and 2015 that we determine is prudent. Excess expenditure is prudent where it reasonably reflects the efficient costs of a business providing AMI services.<sup>5 6</sup>

Our draft decisions for AusNet Services, Jemena and United Energy apply a true-up between approved AMI costs and actual revenues over the 2009–15 period. In addition, AusNet Services, Jemena and United Energy have sought expenditure excesses. We assessed this spending as it exceeds the 2012–15 Approved Budget<sup>7</sup> for each of those distributors. We have approved recovery from consumers of that part of the excess expenditure for 2014 and 2015 which we determined to be prudent.

Not all of the Victorian electricity distributors sought the recovery of excess expenditure for 2014 and 2015 in their applications.

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<sup>1</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council.*

<sup>2</sup> Since the Order was initially made, it has been amended several times. This draft decision applies the latest version of the Order made 15 June 2016.

<sup>3</sup> *AER, 2009–11 AMI budget and charges determination*, 30 October 2009; *AER, 2012–15 AMI budget and charges determination*, 31 October 2011.

<sup>4</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5L.4.

<sup>5</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5L.4.

<sup>6</sup> See section 2 - Background.

<sup>7</sup> *AER, 2012–15 AMI budget and charges determination*, 31 October 2011.

CitiPower and Powercor spent less than their 2014 and 2015 approved costs and therefore there is no excess expenditure to assess. Underspends by CitiPower and Powercor in 2014 and 2015 will result in savings being returned to customers through a negative transition charge. Accordingly, for CitiPower and Powercor, our draft decisions only apply a true-up between approved AMI costs and actual revenues over the 2009–15 period.

### **Transition charges for 2018**

The Order allows us to apply the recovery of the transition charge in 2017 and in any subsequent years of the 2016–2020 regulatory control period.<sup>8</sup>

Our draft decision is that the transition charges we approve will not be applied by the Victorian electricity distributors in 2017. Instead, they will take effect in 2018.

Following consultation with each of the distributors, we have selected 2018 because it is consistent with our annual pricing approval processes. In accordance with the deadlines set out in the Order, we anticipate making our final determination on the Transition Charges Applications on 16 December 2016. By this time, however, we would have already approved each of the Victorian electricity distributors' 2017 pricing proposals.<sup>9</sup> We have accordingly selected the following year (2018) for the transition charges to be applied. To facilitate this, we have adjusted for the time value of money. This is so that both the Victorian electricity distributors and their customers will be no better or worse off by our selection of 2018 as the year in which the transition charges are levied.

Table 1.1 sets out our draft decision. It shows the expenditure adjustment (\$million 2018) we have determined as a result of our assessment of each Victorian electricity distributors' approved costs and actual AMI revenues over the 2009–15 period. Each of these represents a negative revenue amount. The estimated bill impact of each adjustment, to be applied via a transition charge in 2018, is also shown. This shows that for each distributor revenues will be returned to customers and will result in lower annual charges.

**Table 1.1 Draft decision on transition charge (\$2018)**

	Transition charge revenue adjustment	Estimated bill impact
AusNet Services	(\$62.1 million)	(\$83.15)
CitiPower	(\$1.8 million)	(\$5.60)
Jemena	(\$16.5 million)	(\$48.59)
Powercor	(\$9.8 million)	(\$12.14)
United Energy	(\$3.9 million)	(\$5.63)

<sup>8</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5L.3.

<sup>9</sup> NER, clause 6.18.2(a)(2). The deadline for pricing proposals is 30 September 2016.

Source: AER analysis.

Notes: When discounting the transition charge to a 2018 NPV, we used forecast CPI for the 2018 year. We also applied a forecast WACC for the 2017 and 2018 years. We will update these forecast CPI and WACC values for actuals when we apply the transition charge through our 2018 annual pricing approval processes.

Table 1.2 sets out our estimate of the price path for alternative metering services for each Victorian distributor in the current 2016–20 regulatory control period. It shows that our draft decision would give rise to a large fall in metering prices in 2018 followed by an increase in the following year. We are open to consulting with stakeholders on taking steps to smooth this price path in our final decision.

**Table 1.2 Indicative average annual metering bill in Victoria (\$ 2018)**

	2016	2017	2018	2019	2020
AusNet Services	130.19	127.31	23.13	88.78	74.19
CitiPower	100.74	88.75	79.19	81.01	77.39
Jemena	134.21	88.56	41.66	91.99	93.84
Powercor	100.50	90.36	72.48	80.04	75.70
United Energy	93.23	65.52	57.08	60.07	57.57

Source: AER analysis.

### *Invitation for submissions*

We are seeking submissions from interested parties in relation to this draft decision on the five Victorian electricity distributors' Transition Charges Applications. Submissions on our draft decision close 2 November 2016.

We note that we have taken into account a late submission received from the Victorian Government<sup>10</sup> to the extent possible given our timeframe for this draft decision. In addition to inviting comment on our draft decision, we seek comment on the Victorian Government's submission also as we will be able to fully take this submission and any responses to it into account when making our final decision.

We prefer that all written submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information are asked to provide both confidential and non-confidential versions of their submission. All non-confidential submissions will be placed on our website [www.aer.gov.au](http://www.aer.gov.au).

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<sup>10</sup> Department of Environment, Land, Water & Planning, Submission on Advanced metering infrastructure Transition Charges Applications 2017, 30 August 2016.



We will treat all information and documents provided to us as part of this process in accordance with the ACCC/AER's Information Policy (June 2014), which is available on our website.

Submissions can be sent electronically to [AERInquiry@gov.au](mailto:AERInquiry@gov.au).

Alternatively, they can be sent to:

Mr Chris Pattas  
General Manager  
Networks  
Australian Energy Regulator  
GPO Box 520  
Canberra ACT 2601

Inquiries on this matter should be directed to the Network Regulation Branch (Melbourne office) of the AER on 03 9290 1444.

**Table 1.3 Timetable for transitional charge determination**

Submission on applications closed	19 July 2016
AER draft decision	20 September 2016
Submission on AER draft decision close	2 November 2016
AER final decision	16 December 2016

## 2 Background

In 2006, the Victorian Government mandated the roll-out of AMI for all customers consuming less than 160 MWh per annum. This involved the replacement of manually read meters with 'smart meter' technology that allows for the remote communication of a customer's half-hourly consumption data to an electricity distributor.

### *AMI roll-out*

The regulatory arrangements relating to the AMI roll-out in Victoria were initially set out in an August 2007 Order made under the *Electricity Industry Act 2000* (Vic).

The Order adopts a 'cost pass through' regulatory model. Under this model, the recovery of costs incurred in relation to the AMI roll-out involves the following three processes:

1. setting AMI budgets at the beginning of a period<sup>11</sup>
2. making determinations on revised charges that update for actual expenditure<sup>12</sup>
3. the approval of a transition charge that corrects for the difference between costs and revenues over the entirety of the 2009–15 period and which includes an assessment of any excess expenditure for the last two years of the rollout, 2014 and 2015.<sup>13</sup>

This draft decision relates to the third process of the cost pass through model. In making this draft decision, we are nonetheless required to consider past AMI budget and revised charges determinations.

### **AMI budget determinations**

We set budgets for two separate periods.

The first, published in October 2009, applied from 1 January 2009 to 31 December 2011 (2009–11 Approved Budget). The second, published in October 2011, applied from 1 January 2012 to 31 December 2015 (2012–15 Approved Budget).

The framework under the Order in respect of the two budget periods was similar. It required the Victorian electricity distributors to provide a budget for the AMI roll-out and operation as part of its budget application to us.<sup>14</sup> We approved that proposed budget unless it could be established that the expenditure was for activities that were out of scope or not prudent.<sup>15</sup>

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<sup>11</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5A.2

<sup>12</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5G.3

<sup>13</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5L.

<sup>14</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5A.

<sup>15</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5C.2.

## Revised charges

Our approved budgets were updated by revised charges determinations.

The regulatory framework governing the AMI roll-out required us to determine revised charges for the years commencing 1 January 2011, 2013, 2014 and 2015.<sup>16</sup>

The setting of revised charges involved a reconciliation process. We determined AMI budgets based on *forecast* expenditure. The revised charges adjusted for this by updating for *actual* expenditure.

The process for setting revised charges operated as follows. The Victorian electricity distributors submitted revised charges applications for a particular year ('year t').<sup>17</sup> These applications contained audited accounts on their actual expenditure incurred in the previous year (t - 1).<sup>18</sup> Our role was to consider the applications and make a determination on revised charges that would apply in the following year ('year t + 1').<sup>19</sup>

In making revised charges determinations, we could consider applications for 'expenditure excess'.<sup>20</sup> That is, expenditure that has been incurred in excess of the 2009–11 or 2012–15 Approved Budgets. The process for assessing whether excess expenditure should be included in a revised charges determination was set out in the Order.<sup>21</sup> Broadly, it involved considering whether the expenditure was for activities that were within scope and prudent.

The Order also allowed us to defer the assessment of revised charges applications that were due in 2014 and 2015 because the AER was undertaking a revenue determination review under the National Electricity Law and Rules for each of the Victorian distributors for the 2016–2020 period at this time, with the final decision made by the AER in May 2016 (2016–2020 distribution determinations). These revenue determinations also set AMI charges over this (2016–2020) period. As a result, we did not make AMI revised charges determinations in 2014 and 2015. In this draft decision we must therefore consider actual expenditure in those years when considering whether to apply transition charges that true up costs and revenues over the entire 2009–15 period.

## Transition charge

We are required to set transition charges to be recovered in 2017 and in any subsequent years of the 2016–20 regulatory control period.<sup>22</sup>

The amount to be recovered through a transition charge is:

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<sup>16</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5G.

<sup>17</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5G.2.

<sup>18</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5H.1 and 5I.2.

<sup>19</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5G.2.

<sup>20</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5I.5.

<sup>21</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5I.5 to 5I.7B.

<sup>22</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5L.3.

the difference between the future value in 2017 (or 2018) dollars of costs and the future value of revenue for the [2009–15 period].<sup>23</sup>

In effect, the transition charge is a true up between costs and revenues over the AMI roll-out period from 1 January 2009 to 31 December 2015. The approval of a transition charge for a distributor will have the effect of increasing or decreasing the revenue that can be recovered from customers. It also acts as a single year adjustment to our 2016–2020 distribution determinations on the Victorian distributors' revenue for metering (AMI) services for the current 2016–2020 regulatory control period, as explained below

### ***Post AMI roll-out: 2016–2020 determination***

With over 2.8 million meters installed across the state,<sup>24</sup> the Victorian electricity distributors have now effectively completed their AMI roll-out and entered into a business as usual phase in their smart meter operations.

As part of our 2016–2020 distribution determinations, we set revenues for the post AMI roll-out phase.<sup>25</sup> This means now that smart meters have been rolled out, the ongoing costs related to those meters has been incorporated into the current revenue determinations for the 2016–2020 regulatory control period. These determinations are made under the National Electricity Law (NEL) and National Electricity Rules (NER).<sup>26</sup>

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<sup>23</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5L.3.

<sup>24</sup> Victorian Government, Department of Economic Development, Jobs, Transport and Resources <http://www.smartmeters.vic.gov.au/about-smart-meters/end-of-rollout>, accessed 11 October 2015.

<sup>25</sup> See: [http://www.aer.gov.au/networks-pipelines/determinations-access-arrangements?ff0\]=field\\_accr\\_aer\\_region%3A15&ff1\]=field\\_accr\\_aer\\_segment%3A10&ff2\]=type%3Aaccr\\_aer\\_de termination](http://www.aer.gov.au/networks-pipelines/determinations-access-arrangements?ff0]=field_accr_aer_region%3A15&ff1]=field_accr_aer_segment%3A10&ff2]=type%3Aaccr_aer_de termination)

<sup>26</sup> Subject to certain modifications set out in the *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*.

### 3 Assessment approach

The Order sets out the assessment framework for our draft decision on the five Victorian electricity distributors' transition charge applications.

#### 3.1 Calculation of transition charge

Under the Order, the transition charge comprises of two 'true-up' adjustments: the 'revenue and costs true-up' and the 'metering asset base true-up'. These are outlined below.

The value of these (true-up) adjustments are also effected by the ex post review of the Victorian distributors' expenditure in 2014 and 2015, which we refer to as our assessment of any expenditure excess in these years. In accordance with the Order, this ex post review must be conducted as part of this transition charges decision.

##### 3.1.1 Revenue and costs true-up

The first adjustment required under the Order corrects for:

the difference between the future value in 2017 [or 2018] dollars of costs and the future value of revenue for the [2009–15 period].<sup>27</sup>

The term 'costs' refers to the 'building block costs' we have determined to be recoverable from customers in our previous budget determinations. For the purposes of the transition charge, 'revenue' is what has been actually recovered from customers and is to be calculated 'by using the actual revenue figures in the distributor's Regulatory Accounting Statements for each year of the [2009–15 period]'.<sup>28</sup> Table 3.1 sets out how AMI revenues and costs are to be calculated.

**Table 3.1 Calculation of costs and revenue under the Order**

Year	Costs	Revenue
2009, 2011, 2012 and 2013	<p><b><u>Already determined.</u></b></p> <p>Building block costs are taken from the Revised Charges Determinations.</p>	<p>Revenue is to be calculated by using the actual revenue figures in the distributor's Regulatory Accounting Statements for each year of the initial regulatory period (2009–15).</p>
2010	<p><b><u>Already determined.</u></b></p> <p>Building block costs are taken from the 2012–15 Approved Budget.</p>	
2014, 2015	<p><b><u>Not yet determined.</u></b></p> <p>We must determine the 2014 and 2015 building block costs in this</p>	

<sup>27</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5L.3.

<sup>28</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5L.4(b).

Source: *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5L.4.*

As noted in Table 3.1 above, we are required to determine the Victorian electricity distributors' 2014 and 2015 approved building block costs in making this determination. In doing this we must have regard to a number of factors. These include the application of 'scope' and 'prudence' tests.<sup>29</sup> See section 3.2 for more information.

### 3.1.2 Metering asset base true-up

The second true-up adjustment relates to the metering asset base (MAB).

We calculated an opening MAB value for each of the Victorian electricity distributors in our 2016–2020 distribution determination. These MAB values were based on actual capex from 2011 to 2013. However, we used forecast capex for 2014 and 2015. These forecast amounts were taken from the Victorian distributors' 2015 AMI Charges Revision Applications.<sup>30</sup> The 2014 and 2015 capex amounts that were an input into our calculation of the opening MAB in our 2016–20 distribution determination, therefore, reflect the Victorian distributors' forecasts, submitted in August 2014.

To update these capex forecast values with actual amounts, we are required to make a revenue adjustment.<sup>31</sup> This involves, first, calculating the return on capital and depreciation building blocks components using the opening MAB value set in our 2016–2020 distribution determination. We are then required to perform the same calculation again. However, when making the calculation the second time we are required to use the actual capex amounts for 2014 and 2015 which have been determined in this draft decision. The difference between these two calculations produces a higher (or lower) revenue amount which a distributor must recover (or return) to customers. This higher (or lower) amount is included or accounted for in the transition charge.

Through this process, we will not be actually amending the MAB value or building blocks approved in the 2016–2020 distribution determination. They will remain the same. Any differences in the return on capital and depreciation building blocks will be adjusted for via a single-year revenue adjustment, incorporated into the transition charge. In this way, we do not have to reopen the 2016–2020 distribution determination in relation to smart metering services.

## 3.2 Assessment of 2014 and 2015 costs

As part of our transition charges determination, we are required to conduct a review of the Victorian electricity distributors' actual expenditure in 2014 and 2015.

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<sup>29</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5L.4.*

<sup>30</sup> 2015 AMI charges revision application, August 2014.

<sup>31</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5L.7.*

Our determination on the AMI costs in 2014 and 2015 follows a similar process to making past Revised Charges Determinations (see section 2 above). This involves considering the *forecast* expenditure allowed in the 2012–15 Approved Budget and reconciling those amounts with the *actual* capex and opex incurred in the 2014 and 2015 years.

We are not required to accept all expenditure that has been incurred. We can approve only capex and opex that satisfies the 'scope' and 'prudence' tests.<sup>32</sup>

### 3.2.1 Scope test

We are to include actual 2014 and 2015 capex and opex that is:

- certified by an auditor as for activities within scope (AMI related activities) and has been incurred in the amount claimed
- for activities within scope (AMI related activities) as determined by us; and
- which does not exceed the approved budget.<sup>33</sup>

In practice, this means that if actual capex and opex in 2014 and 2015 is *less than* forecast in the 2012–15 Approved Budget, then we will accept it subject to it being certified by an auditor and relating to AMI matters.

CitiPower and Powercor submitted Transition Charges Applications that did not exceed the approved budget. Our assessments for these businesses are outlined in sections 7 and 8, respectively.

### 3.2.2 Prudence test

When the total capex and opex is *greater than* the approved budget, the Order establishes a process to determine if the 'expenditure excess' should be approved.<sup>34</sup> If the expenditure excess is approved under this process, then the distributor will be able to recover it from customers via a transition charge.<sup>35</sup>

The process for determining whether an expenditure excess should be included in the calculation of a transition charge is set out in clauses 5I of the Order. It involves assessing whether the expenditure excess is 'prudent'.<sup>36</sup> This is defined to mean 'reasonably reflects the efficient costs of a business providing the Regulated Services (AMI roll-out associated obligations)'.<sup>37</sup>

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<sup>32</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5I.2 to 5I.10.

<sup>33</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5I.2.

<sup>34</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5I.2 to 5I.10.

<sup>35</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5L.4.

<sup>36</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5I7.

<sup>37</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5I.7A.

In deciding whether we are satisfied that expenditure 'reasonably reflects the efficient costs of a business providing the Regulated Service', we are able to take into account the following factors.

The Order provides that where the expenditure excess is a contract, it will reasonably reflect the efficient costs of a business providing the Regulated Service if the contract was let in accordance with a competitive tender process.<sup>38</sup>

Additionally, we may take into account the following when determining whether expenditure incurred in 2014 and 2015 in excess of the 2012–15 Approved Budget would satisfy the prudence test in the Order.<sup>39</sup>

- information available to the distributor
- nature of provision, installation and operation of AMI
- the roll-out obligation (i.e. the distributors' obligations to roll-out AMI according to the Order timetable)
- state of relevant technology
- project risks inherent in the AMI project
- relevant market conditions
- other metering regulatory obligations
- any other relevant matter.

When making our assessment of 2014 and 2015 costs, the Order states that we are required to have regard to 'expenditure of the distributor over the entirety of the [2009–15 period]'.<sup>40</sup>

AusNet Services, United Energy and Jemena submitted Transition Charges Applications that did exceed the approved budget. Our assessments for these businesses are outlined in sections 4, 5 and 6, respectively.

### 3.2.3 Benchmarking

When making this determination, we must take into account 'the expenditure of a benchmark efficient entity'.<sup>41</sup>

#### *Order in council*

In determining what may be or is a benchmark efficient entity, we may, among other things, have regard to:

- meter density

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<sup>38</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5I.7B(c).

<sup>39</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5I.7B(d).

<sup>40</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5I.7AA.

<sup>41</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5I.8A.



- number of meters subject to regulation.<sup>42</sup>

With respect to benchmarking methods, the Order states that we may make use of either or both category level benchmarking and aggregated benchmarking.<sup>43</sup>

When benchmarking we are required to take a number of factors into account. These factors are set out in clause 51.8(c) of the Order. They provide:

- that a distributor is the only distributor that incurs particular expenditure or engages in a particular activity is not a matter, and is not to be taken as a matter, that prevents or limits the use of benchmarking
- that a benchmark efficient entity might not have incurred particular expenditure or engaged in a particular activity is not a matter, and is not to be taken as a matter, that prevents or limits benchmarking of that entity against a distributor or *vice versa*
- the AER is not bound to proceed on the basis that the starting point for benchmarking is what a distributor has in fact done but may instead proceed from the starting point of what a *hypothetical benchmark efficient entity* would have done
- benchmarking may proceed on the basis that a benchmark efficient entity's remotely read interval meters become logically converted remotely read interval meters at either or both different rates and different times from the rates and times of the distributor
- regard may be had to expenditure on Distribution IT Systems
  - where such systems are required for all customers of a distributor and not just distribution services that are metering services
  - where the expenditure has been or is ought to be brought into account as expenditure for the purposes of standard control services.<sup>44</sup>

We therefore must take into account benchmarking, but we are also provided with a degree of discretion as to the benchmarking approach we adopt and how we apply the benchmarking.

### ***Our approach***

We engaged Energeia to assist us in conducting the benchmarking required under the Order. The benchmarking which Energeia performed consisted of both a 'top down' and 'bottom up' comparative analysis.

The top down approach is set out in section 9 of this draft decision. It included both category level and sub–category level benchmarking analysis. The bottom up approach consisted of, among other things, identifying benchmark efficient unit rates for various AMI roll–out activities. This analysis is consistent with how we have

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<sup>42</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5L.8B(a).

<sup>43</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5L.8B(b).

<sup>44</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5L.8B(c).

assessed previous applications made by the Victorian distributors to recover 'excess expenditure'.

In making this draft decision, we have had regard to the top down benchmarking outcomes (section 9) to test the relative efficiency of the Victorian distributors' AMI programs. We have not, however, used that analysis to make specific reductions to any of the distributors' proposed excess expenditure.

When we have not accepted an aspect of the Victorian distributors' proposed excess expenditure we have placed greater reliance on Energeia's bottom up benchmarking approach. In conducting this analysis, Energeia assessed the following key issues:

- benchmark meter installation costs
- volume versus pricing variations in meter installation costs
- efficient project management costs
- benchmark program management costs.

In this draft decision, we have reviewed and accepted Energeia's benchmarking results for each of the businesses. We consider that the reasoning behind Energeia's methodology, as set out in section 3.1 of its report, is sound and the methodology it has applied is in accordance with the Order. Energeia has taken into account limitations in relation to the dataset available and satisfactorily addressed the limitations of category and sub-category level benchmarking for the purposes of assessing particular expenditure under the Order. We also concur with its assessment of the methodologies proposed by some of the distributors for the reasons set out in its report.<sup>45</sup> Energeia accepted some aspects of those methodologies but also identified certain deficiencies.

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<sup>45</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, section 3.1.

## 4 AusNet Services

We do not accept AusNet Services' Transition Charge Application, which proposed a negative transition charge of \$25.5 million (\$2018).<sup>46</sup> In place of its proposal, we have calculated a substitute transition charge.

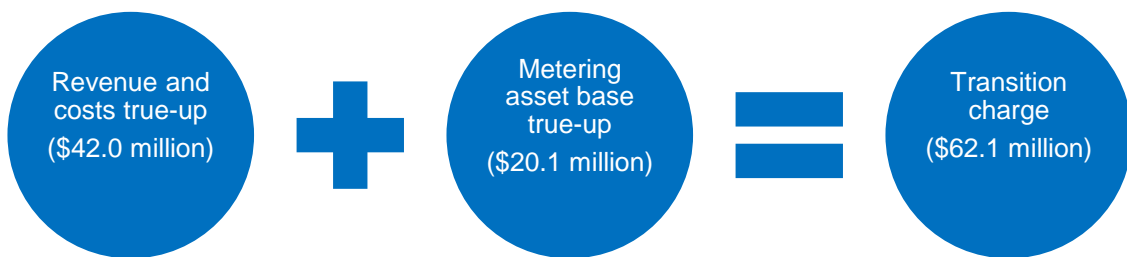
### 4.1 Draft decision

Our draft decision provides for a negative transition charge of \$62.1 million (\$2018).

Under the Order, the calculation of AusNet Services' transition charge must consist of a revenue and costs true-up and a MAB adjustment (see section 3.1).<sup>47</sup> AusNet Services' application included the revenue and costs true-up in the calculation of its proposed transition charge but did not include the MAB adjustment. We have not accepted this aspect of AusNet Services' proposal.

Figure 4.1 sets out the components that make up our draft decision. It shows that our draft decision transition charge consists of a revenue and costs true-up of negative \$42.0 million (\$2018) plus a MAB adjustment of negative \$20.1 million (\$2018) giving a total transition charge of negative \$62.1 million (\$2018).

**Figure 4.1 Draft decision transition charge (\$2018)**



Source: AER analysis

#### 4.1.1 Revenue and costs true-up

We have calculated a negative revenue and costs true-up of \$42.0 million (\$2018).

Our draft decision will provide for a greater return of revenue to customers in the 2018 year of the 2016–2020 regulatory control period. This compares to AusNet Services' proposal that would have meant a return of revenue to customers of \$12.5 million (\$2009) if their revenue and costs true-up was accepted.

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<sup>46</sup> AusNet Services proposed a transition charge of \$12.5 million in NPV \$2009 terms. This has been adjusted for a NPV in \$2018 terms.

<sup>47</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5L.4 and 5L.7 to 5L.12.

The key differences between our draft decision and AusNet Services' proposal are:

- the net present value (NPV) to which we have discounted
- our assessment of AusNet Services' proposed 2014 and 2015 excess expenditure.

In its proposal AusNet Services discounted its true-up amount to a 2009 NPV. Since the transition charge will apply in 2018, we do not consider this aspect of AusNet Services' proposal to reflect the requirements of the Order.<sup>48</sup>

When we correctly discounted AusNet Services' proposal to its 2018 NPV, we calculate that the distributor's proposal actually equates to a negative revenue and costs true-up of \$25.5 million (\$2018). This is still a smaller return to customers than the \$42.0 million (\$2018) we have calculated in this draft decision. The reason for this is that we have not accepted all of AusNet Services' proposed 2014 and 2015 excess expenditure. Our reasons on this aspect of our draft decision are set out in section 4.2.

To calculate the revenue and costs true-up in accordance with the Order, we followed a series of steps outlined below.

### Step one

The first step we took in calculating AusNet Services' revenue and costs true-up was to verify the distributor's actual AMI revenue recovered from its customers over the 2009–15 period.

Table 4.1 sets out AusNet Services' AMI tariff revenue which we have verified against audited regulatory information notices.

**Table 4.1 AMI tariff revenue (\$m, NPV 2009)**

	2009	2010	2011	2012	2013	2014	2015	Total
Tariff revenue	35.8	57.3	58.4	60.2	67.0	77.3	93.4	449.6

Source: AusNet Services, 2009–15 Regulatory Information Notices.

### Step two

The next step we took was to calculate AusNet Services' approved building block costs or approved budget costs. When doing this, the Order provides that we are required to give consideration to a proposal (if any) to recover excess expenditure incurred in 2014 and 2015.

AusNet Services' proposed to recover \$103.0 million (\$2018) in total excess expenditure (capex and opex) which it incurred in 2014 and 2015. Of this amount, our draft decision accepts \$49.1 million (\$2018). Our reasons are set out in section 4.2.

<sup>48</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5L.3 and 5L. 4.

The revenue impact of our draft decision to accept less excess expenditure than AusNet Services proposed is set out in Table 4.2. It shows that by not accepting the full amount of excess expenditure, AusNet Services' recoverable building block costs are lower than proposed. We convert the values in Table 4.2 from a 2009 NPV to a 2018 NPV in step four below.

**Table 4.2 Approved recoverable costs (\$m, NPV 2009)**

	2009	2010	2011	2012	2013	2014	2015	Total
AusNet Services' proposal	32.8	57.9	68.6	74.0	75.4	66.4	61.9	437.1
AER draft decision	32.8	57.9	68.6	74.0	75.4	61.6	58.7	429.1
Difference	0.0	0.0	0.0	0.0	0.0	(4.8)	(3.2)	(8.0)

Source: AER analysis.

### Step three

The third step we took was to calculate the difference between AusNet Services' revenue and approved costs. Table 4.3 sets out this calculation in 2009 NPV terms as AusNet Services had used in its proposal.

**Table 4.3 Revenue and costs true-up (\$m, NPV 2009)**

	Revenue	Approved costs	True-up
AusNet Services' proposal	449.6	437.1	(12.5)
AER draft decision	449.6	429.1	(20.5)

Source: AER analysis.

### Step four

Our final step was to discount the true-up amount to its correct NPV.

We have decided in this draft decision to apply the transition charge in the 2018 year of the Victorian electricity distributor's 2016–2020 regulatory control period. We therefore discounted the amount we calculated in step three to its 2018 NPV.<sup>49</sup> This amount is set out in Table 4.4.

<sup>49</sup> When discounting to a 2018 NPV, we used forecast CPI for the 2018 year. We also applied a forecast WACC for the 2017 and 2018 years. We will update these forecast CPI and WACC values for actuals when we apply the transition charge through our 2018 annual pricing approval processes.

**Table 4.4 Draft decision on revenue and costs true-up (\$m, NPV 2018)**

	True-up
AER draft decision	(42.0)

Source: AER analysis.

### 4.1.2 MAB true-up

We have calculated a negative MAB true-up of \$20.1 million (\$2018).

#### *Step one*

The first step we took was to recalculate the 2016–2020 opening MAB value.

This process involved a comparison. In particular, we compared the opening MAB value which we determined in our 2016–2020 distribution determination with the opening MAB value that we have calculated in this transition charges draft decision. Table 4.5 sets out that recalculation.

**Table 4.5 Calculation of opening MAB value (\$m, 2008)**

	2011	2012	2013	2014	2015	Opening MAB
2016–2020 Victorian determination	202.3	288.1	344.9	350.1	311.6	311.6
Transition charge draft decision	202.3	288.1	344.9	320.5	283.9	283.9

Source: AER analysis.

As shown in Table 4.3 above, the opening MAB value we have calculated in this transition charges draft decision is lower than in our 2016–2020 distribution determination. The reason for this is that our 2016–2020 distribution determination relied on forecast data. In particular, when determining the capex to be rolled into the MAB for the 2014 and 2015 years we used AusNet Services' forecast capex in its 2015 AMI Charges Revision Applications.<sup>50</sup> In effect, we used a forecast AusNet Services had made in August 2014, which had not been subject to a prudence assessment.

Our transition charge draft decision, by contrast, takes AusNet Services *actual* capex in 2014 and 2015 into consideration. We have also considered a proposal from AusNet Services to recover excess capex in the 2014 and 2015 years. With respect to this, we have only rolled into our recalculation of the MAB, any excess capex that we consider

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<sup>50</sup> 2015 AMI charges revision application, August 2014.

to be prudent. Our reasons regarding this prudency assessment are outlined in section 4.2 below.

### Step two

Once we had recalculated AusNet Services' MAB value, the next step we took was to escalate the value of the recalculated MAB value to 2015 dollar terms.

The reason why we escalated it to 2015 dollar terms was that this is the value which we applied in our 2016–2020 distribution determination. Table 4.6 sets out the results of the escalation we applied.

**Table 4.6 Recalculation of opening MAB value**

	(\$m, 2008)	(\$m, 2015)
Opening MAB as of 1 January 2016	283.9	345.2

Source: AER analysis.

### Step three

The next step we took was to compare the revenue recoverable from the opening MAB we set our 2016–2020 distribution determination with our recalculation of the MAB in this transition charge draft decision. Table 4.7 sets out the results of this comparison.

**Table 4.7 Recalculation of MAB revenue (\$million)**

	2016 (\$nominal)	2017 (\$nominal)	2018 (\$nominal)	2019 (\$nominal)	2020 (\$nominal)	Total (\$Dec 2015)
2016–2020 Victorian determination	65.1	64.6	64.0	49.9	36.7	237.7
Transition charge draft decision	61.0	60.6	60.0	45.0	33.3	220.7
Difference						(17.1)

Source: AER analysis.

### Step four

The final step we took to calculate the MAB adjustment was to discount the revenue difference calculated in step 3 to its 2018 NPV.<sup>51</sup> When we did this, we calculated a negative MAB adjustment of \$20.1 million (\$2018).

<sup>51</sup> When discounting to a 2018 NPV, we used forecast CPI for the 2018 year. We also applied a forecast WACC for the 2017 and 2018 years. We will update these forecast CPI and WACC values for actuals when we apply the transition charge through our 2018 annual pricing approval processes.

## 4.2 Reasons for draft decision

Our draft decision does not accept the proposed excess capital and operating expenditure included in AusNet Services' transition charges application. Our reasons are outlined below.

### 4.2.1 Expenditure excess

Our draft decision accepts \$49.1 million (\$2018) in 2014 and 2015 expenditure excess which AusNet Services proposed to recover through the transition charge. This amounts to approximately 48 percent of the \$103.0 million (\$2018) AusNet Services sought to recover. Table 4.8 sets out our draft decision.

**Table 4.8 Draft decision on AusNet Services' application (\$m 2018)**

	Proposed	Draft decision
<u>Capex</u>		
Meter supply	25.6	13.9
Meter installation	15.5	7.4
IT	33.3	5.7
Subtotal: capex	74.4	26.9
<u>Opex</u>		
Meter reading	3.4	1.7
Meter maintenance	2.0	2.0
Meter data management	4.8	4.8
Communications infrastructure	4.0	4.0
IT	8.5	8.5
Customer service and PM	5.8	1.1
Subtotal: opex	28.6	22.2
Total excess expenditure	103.0	49.1

Source: AER analysis.

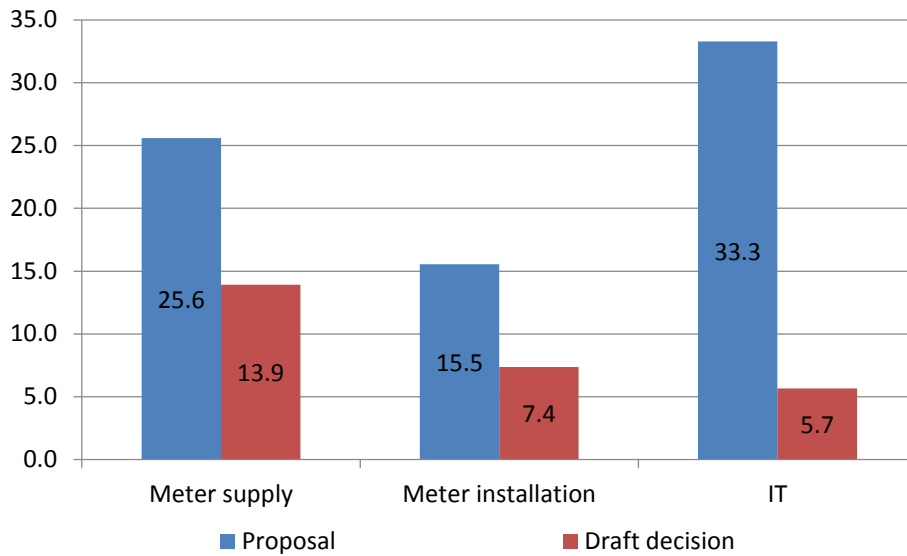
### 4.2.2 Excess capital expenditure

We accept \$26.9 million (\$2018) of AusNet Services' proposed excess capital expenditure for 2014 and 2015. Our draft decision is that this amount meets the requirements in the Order to be recovered through the transition charge.

Figure 4.2 sets out the components of our draft decision on AusNet Services' excess capital expenditure. In reaching our draft decision on each component we have had regard to analysis performed by Energeia.



**Figure 4.2 AER draft decision on AusNet Services' capex (\$m 2018)**



Source: AER analysis; Energeia, Draft decision DNSP excess expenditure model, 14 September 2016, 'ANS\_M' tab.

We should note that Energeia's analysis included both 'top down' and 'bottom up' benchmarking (see section 3.2.3 above).

The top down analysis is set out in section 9. In making this draft decision, we have had regard to the top down analysis to test the relative efficiency of AusNet Services' AMI roll-out against that of the other Victorian distributors. We have not, however, used that top down approach to make specific reductions to AusNet Services' proposed 2014 and 2015 excess capital expenditure.

Instead, we have principally relied on Energeia's bottom up benchmarking. This bottom up approach consisted of analysis performed by Energeia on the efficient benchmark unit rates for smart meters and meter installations. We also had regard to Energeia's benchmarking of AusNet Services' IT capex against the expenditure incurred by CitiPower and Powercor. Each of AusNet Services' excess capital expenditure categories are considered below.

***Meter supply***

We accept \$13.9 million (\$2018) in excess capital expenditure for 'meter supply'. This is equal to around 55 percent of AusNet Services proposed \$25.6 million (\$2018) in excess capital expenditure for the acquisition of additional metering units. Table 4.9 sets out our draft decision.

**Table 4.9 Draft decision on meter supply capex (\$m 2018)**

	Approved budget (2012–15 Budget)	Proposed excess	Draft decision
2014	2.4	24.2	12.5

2015	2.3	1.4	1.4
Total	4.7	25.6	13.9

Source: AER analysis.

## 2014 meter supply

We accept \$12.5 million (\$2018) in excess expenditure for 2014 meter supply.

The Victorian Government submitted that an issue for us to consider is whether the number of 3G communications modules required is higher than would have been had AusNet Services converted to a mesh radio communications technology during the rollout when there was information showing that it was a less costly, market proven solution.<sup>52</sup> We considered this issue in arriving at our draft decision.

Table 4.10 sets out the components of our draft decision. It shows that we accept the total volume of AusNet Services' proposed additional metering units, which amounts to 145 856. We have nonetheless based our draft decision on a different technology mix between 3G, WiMAX and mesh radio communication modules that we consider is more efficient than AusNet Services proposed as explained further below.

**Table 4.10 Draft decision on 2014 meter supply capex volumes**

	Approved volumes (2012–15 Budget)	Proposed additional volumes	Draft decision
Meters	10 112	0	0
3G modules	0	122 579	4 376
WiMAX modules	0	23 277	0
Mesh radio modules	0	0	141 480
Total metering units	10 112	145 856	145 856

Source: AER analysis.

### *Total metering unit volumes*

We accept AusNet Services' total proposed additional metering units of 145 856.

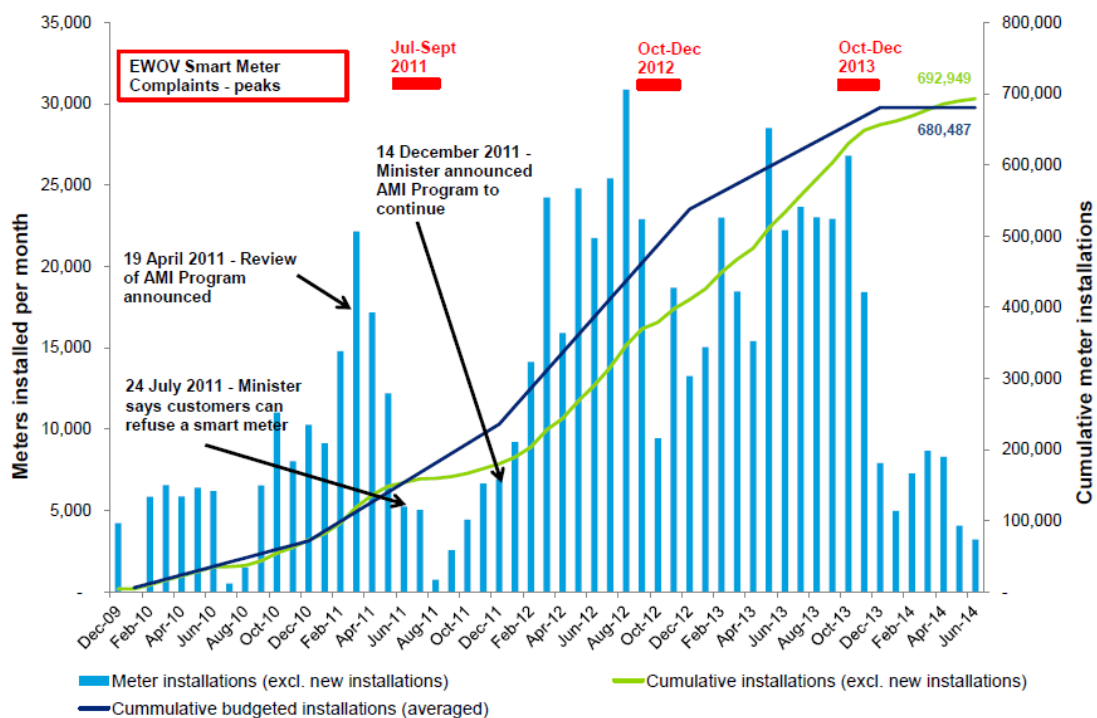
Our 2012–15 Approved Budget forecast AusNet Services procuring 10 112 metering units in 2014. This forecast was based on a requirement in the Order that AusNet Services would have to complete its roll-out by the end of 2013.

<sup>52</sup> Department of Environment, Land, Water & Planning, Submission on Advanced metering infrastructure Transition Charges Applications 2017, 30 August 2016, p. 1.

The Order was amended on 10 December 2013 to require the Victorian electricity distributors to continue to use their best endeavours to install a complying AMI meter for prescribed customers. This new regulatory requirement allowed AusNet Services to continue to roll-out AMI meters after 2013.

There were external factors that are likely to have contributed to the extension of AusNet Services' AMI roll-out beyond the original completion date. Figure 4.3 shows AusNet Services' AMI deployment schedule since the commencement of the roll-out period until June 2014. It highlights the timing of external factors and gives an indication of the impact that they may have had on AusNet Services' deployment of AMI meters.<sup>53</sup> Such external factors included a 2011 review of the AMI roll-out which AusNet Services stated led to 13 months of uncertainty between November 2010 and December 2011.<sup>54</sup> We accept that such uncertainty is likely to have increased customer concerns regarding AMI meters and, potentially, lead to a higher rate of customer refusals. This is consistent with our assessment in our 2014 excess charges report.

**Figure 4.3 AusNet Services AMI deployment**



Source: AusNet Services, AMI Transition Charges Application, 31 May 2016, p. 11.

<sup>53</sup> AusNet Services, *AMI Transition Charges Application*, 31 May 2016, p. 28.

<sup>54</sup> AusNet Services, *AMI Transition Charges Application*, 31 May 2016, p. 28.

Our draft decision accepts that regulatory changes to the AMI roll-out and customer concern about remotely read interval meters are likely to have led to delays in AusNet Services' deployment program. These delays were out of AusNet Services' control and on this basis we accept the proposed additional metering units of 145 856 needed to be installed after 2013.

### *Technology mix*

We do not accept the technology mix that makes up AusNet Services' 2014 excess capital expenditure proposal (see Table 4.10 above). Our draft decision applies a mix of technologies which we consider to reflect a prudent and efficient entity's provision of AMI services.

AusNet Services roll-out applied a mix of communication technologies. Initially, it sought to use WiMAX for the majority of installations. But in more recent years, it has begun a transition to a mesh radio solution. Additionally for a proportion of customers, AusNet Services has used 3G communications technology. This was to provide 'infill coverage where the [WiMAX or mesh radio] communication technology coverage was not available or was insufficient'.<sup>55</sup> Compared to WiMAX and mesh radio, 3G is a more expensive form of communications technology.

In the 2012–15 Approved Budget, we forecasted a 3G infill of 3 percent. AusNet Services' transition charges application stated that this was not a sufficient allowance. Its principal argument was that in calculating an infill level of 3 percent we used Powercor's 3G coverage as the efficient benchmark. For AusNet Services, this was not appropriate given findings from a geospatial consultant, We–do–IT, that AusNet Services' network is among the most difficult terrain of all the Victorian distributors.<sup>56</sup> Implicit in this finding is the contention that a greater 3G infill is needed for more difficult terrains.

Energeia provided us with advice on AusNet Services' efficient level of 3G infill. It observed that AusNet Services' proposal represented the use of 3G communications technology at 17.3 percent of total metering installations.<sup>57</sup> Energeia stated that this level of infill was not supported by the technical design of AusNet Services' communications network. In particular, the proposed infill of 17.3 percent was based on using a 'micro access point' device that was not available when AusNet Services was designing its communications network.<sup>58</sup> Energeia concluded that in the absence of technical design information supporting AusNet Services' proposed infill level, the 2012–15 Approved Budget of 3 percent should be maintained.<sup>59</sup>

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<sup>55</sup> AusNet Services, *AMI Transition Charges Application*, 31 May 2016, p. 24.

<sup>56</sup> AusNet Services, *AMI Transition Charges Application*, 31 May 2016, p. 26.

<sup>57</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 32.

<sup>58</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 32.

<sup>59</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 32.

Based on Energeia's advice, we do not accept AusNet Services' proposals. We are not satisfied that AusNet Services has provided sufficient information that supports an alternative benchmark comparator for determining its efficient level of 3G communications infill. We have accordingly maintained the 3 percent infill in making this draft decision. This led us to substituting AusNet Services' proposed 122 579 3G communication modules with 4 376 (see Table 4.10 above).

For the remaining 141 480 additional meter unit volumes accepted in this draft decision, we have determined a capital expenditure excess based on a mesh radio equivalent unit cost. Consistent with past Tribunal decisions and AER determinations,<sup>60</sup> we have not accepted any costs associated with WiMAX communication modules (see Table 4.10 above). This aspect of our draft decision, along with the application of a 3G infill of 3 percent, leads to us substituting AusNet Services' proposed 2014 additional capex of \$24.2 million with \$12.5 million (\$2018).

### 2015 meter supply

We accept \$1.4 million (\$2018) in excess expenditure for 2015 meter supply.

Table 4.11 sets out the components of our draft decision. It shows that we accept the total volume of AusNet Services' proposed additional metering units, which amounts to 12 570. We have accepted these volumes because we are satisfied that regulatory changes and customers concerns caused delays in AusNet Services' AMI meter deployment. We also accept the technology mix which AusNet Services proposed given that it consisted of complete metering units using mesh radio modules.

**Table 4.11 Draft decision on 2015 meter supply capex volumes**

	Approved volumes (2012–15 Budget)	Proposed additional volumes	Draft decision
Meters	9 852	12 570	12 570
3G modules	0	0	0
WiMAX modules	0	0	0
Mesh radio modules	0	0	0
Total metering units	9 852	12 570	12 570

Source: AER analysis.

### Meter installation

We accept \$7.4 million (\$2018) in excess capital expenditure for 'meter installation'. This is equal to about 48 percent of AusNet Services' proposed \$15.5 million (\$2018)

<sup>60</sup> *Appeal by SPI Electricity Pty Ltd [2012] ACompT 11; AER, 2012–15 AMI SPI Electricity Pty Ltd Budget and Charges Determination - amendments pursuant to the Australian Competition Tribunal's Orders, February 2013.*

in excess capital expenditure for installing meters in 2014 and 2015. Table 4.12 sets out our draft decision.

**Table 4.12 Draft decision on meter installation capex (\$m 2018)**

	Approved budget (2012–15 Budget)	Proposed excess	Draft decision
2014	0.0	14.3	6.8
2015	0.0	1.3	0.6
Total	0.0	15.5	7.4

Source: AusNet Services, AMI Transition Charges Application, 31 May 2016, p. 23 and p. 27.

### 2014 meter installation

We accept \$6.8 million (\$2018) in excess expenditure for 2014 meter installation.

Table 4.13 sets out the components of our draft decision. It shows that we accept the volume of meter installations associated with 'faults' and 'roll-out – meter installations' but not 'standalone 3G modules'. This has led to us substituting AusNet Services' proposed 2014 volume of metering installations of 110 944 with 41 082.

**Table 4.13 Draft decision on 2014 meter installation capex volumes**

	Approved volumes (2012–15 Budget)	Proposed additional volumes	Draft decision
Faults	0	4 060	4 060
Roll-out – Meter installations	0	37 022	37 022
Standalone 3G modules	0	69 862	0
Total	0	110 944	41 082

Source: AER analysis.

In support of the proposed excess expenditure associated with its standalone 3G module installations, AusNet Services stated that it experienced delays in the delivery of hardware. Specifically, it stated that 'there was a delay in the delivery of the 3G communication modules in 2013 as a result of the impact of policy changes'.<sup>61</sup> This prompted AusNet Services to adopt a two-step installation process. This involves the installation of a number of its meters in 2013 and, after this, a retrofit installation of 3G communication modules in 2014.

<sup>61</sup> AusNet Services, AMI Transition Charges Application, 31 May 2016, p. 29.

The Victorian Government submitted that it considers the installation of meters without communications modules to be an inefficient practice as this practice required two site visits rather than one.<sup>62</sup> We agree with the Victorian Government's view.

We are not satisfied that the two-step process AusNet Services adopted reasonably reflects the efficient costs of a business providing AMI services. Energeia notes that the process of retrofitting meters with 3G communication modules led to an increase in costs of between \$120 to \$351 (\$nominal) per module installation. This is compared to a process where both the meter and its communications module were installed at the same time. Given this inefficiency, we consider the associated excess capital expenditure is not prudent.<sup>63</sup>

When we apply our draft decision on 2014 meter installation capex volumes in conjunction with the advice we have received from Energeia on the efficient unit costs, we arrive at a substitute excess capital expenditure of \$6.8 million (\$2018).

### 2015 meter installations

We accept \$0.6 million (\$2018) in excess expenditure for 2014 meter installation.

Table 4.14 sets out the components of our draft decision. It shows that AusNet Services only proposed a level of volumes associated with 'faults', which we have accepted.

**Table 4.14 Draft decision on 2015 meter installation capex volumes**

	Approved volumes (2012–15 Budget)	Proposed additional volumes	Draft decision
Faults	0	3 319	3 319
Roll-out – Meter installations	0	0	0
Standalone 3G modules	0	0	0
Total	0	3 319	3 319

Source: AER analysis.

When we apply our draft decision on 2014 meter installation capex volumes in conjunction with the advice we have received from Energeia on the efficient unit costs, we arrive at a substitute excess capital expenditure of \$0.6 million (\$2018).

<sup>62</sup> Department of Environment, Land, Water & Planning, Submission on Advanced metering infrastructure Transition Charges Applications 2017, 30 August 2016, p. 2.

<sup>63</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5I.7 and 5I7A.

## IT capex

We accept \$5.7 million (\$2018) in excess capital expenditure for 'IT systems'. This is equal to about 17 percent of AusNet Services' proposed \$33.3 million (\$2018) in IT excess capital expenditure. Table 4.15 sets out our draft decision.

**Table 4.15 Draft decision on IT capex (\$m 2018)**

	Approved budget (2012–15 Budget)	Proposed excess	Draft decision
2014	0.0	9.7	0.0
2015	0.0	23.6	5.7
Total	0.0	33.3	5.7

Source: AER analysis.

In support of its application, AusNet Services noted that its approved budget did not include an allowance for IT expenditure in 2014 and 2015. It submitted that irrespective of this AusNet Services incurred IT capex in those years 'mainly as a result of the complexity of systems implementation, migration and integration task being greater than originally activated'.<sup>64</sup> AusNet Services further stated that in 'determining expenditure to be applying for approval, AusNet Services has excluded all expenditure associated with remediating the AMI IT systems and the WiMAX communication technology'.<sup>65</sup>

Energeia's review of this aspect of AusNet Services' application 'first attempted to determine whether the IT investments were made on a cost savings basis, which resulted in lower cost elsewhere, for example opex'.<sup>66</sup> In response to information requests, no such business cases were provided.<sup>67</sup> This led to Energeia finding that AusNet Services 'is not implementing good investment governance, which would have generated the business cases and made them easily available for review'.<sup>68</sup>

Energeia's assessment also included analysis of whether the proposed excess expenditure for IT capex was driven by timing. More specifically, Energeia sought to determine whether the proposed excess expenditure was due to AusNet Services bringing forward investment in its IT systems in this earlier period which the other Victorian businesses, facing similar circumstances, had decided to defer to a later period and included in their 2016–2020 distribution determination. Figure 4.4 presents Energeia's analysis. It shows that AusNet Services' excess IT capital expenditure in 2014 and 2015 represents a substantially greater investment in IT systems than the

<sup>64</sup> AusNet Services, *AMI Transition Charges Application*, 31 May 2016, p. 35.

<sup>65</sup> AusNet Services, *AMI Transition Charges Application*, 31 May 2016, p. 34.

<sup>66</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 33.

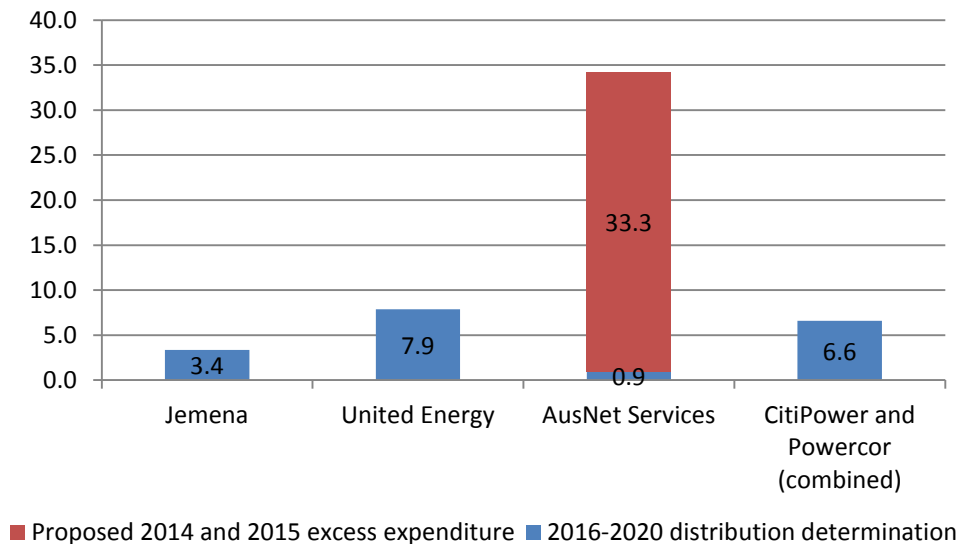
<sup>67</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 33.

<sup>68</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 33.



other Victorian distributors forecast to spend in the 2016–20 distribution determination period. This indicates that the proposed excess IT capital expenditure is not due to timing.

**Figure 4.4 Comparison of AusNet Services' IT capex (\$m 2018)**



Source: Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 32.

Based on Energeia's advice, we consider that an efficient entity in AusNet Services' circumstances would not require any more IT capex than the combined expenditure of CitiPower and Powercor. We have selected the combined IT capex of CitiPower and Powercor to derive our efficient benchmark comparator. This is because Powercor is the closest comparator for AusNet Services, in terms of network characteristics and customer numbers and Powercor shares its IT systems with CitiPower.

Taking this approach, we accept an excess IT capital expenditure of \$5.7 million (\$2018). This amount is equal to the difference between CitiPower and Powercor's IT system capex (\$6.6 million (\$2018)) and AusNet Services IT system capex (\$0.9 million (\$2018)), which we approved in the 2016–2020 distribution determinations. Consistent with Energeia's advice to us, we consider this to be the efficient level of IT capex which a prudent operator in AusNet Services' circumstances would have incurred in 2014 and 2015.

### 4.2.3 Excess operating expenditure

We accept \$22.2 million (\$2018) of AusNet Services' proposed excess operating expenditure. Our draft decision is that this amount meets the requirements in the Order to be recovered through the transition charge. The amount which we accept is equal to around 78 percent of AusNet Services' proposed \$28.6 million (\$2018).

When considering its excess operating expenditure proposal, AusNet Services submitted that we must take our 2016–2020 distribution determination into account. In that determination, we applied a 'base–step–trend' approach to forecasting AusNet

Services' alternative control opex requirement for the 2016–20 regulatory control period. In selecting 2014 as the base year, we declined to make an efficiency adjustment. Our reasoning was that AusNet Services' actual opex in 2014 'does not contain material inefficiencies... on the basis that the Victorian distribution businesses are generally efficient'.<sup>69</sup>

AusNet Services' transition charge application submitted that our assessment of its base opex requirement in the 2016–2020 distribution determination supports its 2014 and 2015 excess operating expenditure proposal. This implies that since we used AusNet Services' actual opex in 2014 to derive a forecast for the 2016–2020 regulatory control period, the proposed 2014 excess operating expenditure should be deemed efficient and, it should be inferred by extension, the proposed 2015 excess operating expenditure.

We do not accept this aspect of AusNet Services' proposal. The assessment under the 2016–2020 distribution determination is distinct from that under the Order. It is undertaken for different purposes and under different rules.

Our decision in the 2016–2020 distribution determination was to approve a total opex forecast for AusNet Services that reasonably reflected the criteria set out in clause 6.5.6 of the NER.

While we built our forecast for the 2016–2020 regulatory control period from past actual costs incurred by AusNet Services in 2014, our forecast did not approve a budget for any particular category of operating expenditure. When we set expenditure forecasts in distribution determinations, we are not seeking to pass through to consumers any particular actual costs of a service provider for any particular project, but rather to set an incentive based overall target forecast for total opex. We explain this task in our Explanatory Statement to our Expenditure Forecast Assessment Guideline as follows:

Two fundamental points are relevant to how we perform our task. First, the NER requires us to form a view on forecast total capex and opex, rather than subcomponents such as individual projects and programs...<sup>70</sup>

The Order on the other hand, requires a very specific and ex-post or backward looking efficiency assessment of AMI project costs under a cost pass through arrangement.

Furthermore, we make each decision at different points in time, and we have different information available to us at those different points in time to which we must have regard. For the purposes of our current draft decision, we have access to additional information about AMI costs for the 2014 and 2015 years which was not before us when we made our 2016–2020 distribution determination.

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<sup>69</sup> AER, *Victorian Distribution Determination 2016–20 Preliminary Decision*, October 2015, p. 16–46.

<sup>70</sup> Better Regulation, *Explanatory Statement, Expenditure Forecast Assessment Guideline*, November 2013, p. 34.

Among the information which was not before us during the 2016–2020 distribution determination is the report of Energeia. This report included benchmarking analysis of a kind provided for under the Order and which under the Order we must take into account.<sup>71</sup> In particular, Energeia's benchmarking analysis found that 'AusNet Services opex per customer over the 2009–15 period was the second highest of all [Victorian electricity distributors]'.<sup>72</sup> It also found that AusNet Services' was '\$100 per meter or \$68 million higher than the benchmark efficient entity for opex, which Energeia concludes was Powercor'.<sup>73</sup> While Energeia accepts that the AER findings in its 2016–2020 distribution determination are 'more relevant' at this level, Energeia's subsequent analysis of selected excess expenditure leads to its finding that opex should be lower than that sought by AusNet Services with respect to meter reading and customer service and project management office expenditure. More information on this analysis is set out in section 9.

The Victorian Government also raised concerns about the extent of the customer service and project management office expenditure excess given that CitiPower, Powercor and United Energy did not seek an expenditure excess for these costs.<sup>74</sup>

The findings we referred to in our 2016–2020 distribution determination when approving a total opex forecast, though relevant, are therefore not determinative of the quite separate decision we must make now under the distinct requirements of the Order.

Based on Energeia's analysis, we conclude that AusNet Services' proposed 2014 and 2015 excess operating expenditure of \$28.6 million (\$2018) does not reasonably reflect the efficient costs of a business providing AMI services, within the terms of the Order.<sup>75</sup> We instead accept \$22.2 million (\$2018). This reflects a \$1.7 million (\$2018) reduction in AusNet Services' meter reading opex, which has been calculated by using our 2016–20 distribution determination meter reading allowance.<sup>76</sup> It also includes a \$4.7 million (\$2018) reduction in customer service and project management costs due to the application of the 2012–15 Approved Budget unit prices for 2013, adjusted for CPI and wage inflation.<sup>77</sup>

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<sup>71</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5I.8A and 5I.8B.

<sup>72</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 36.

<sup>73</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 36.

<sup>74</sup> Department of Environment, Land, Water & Planning, *Submission on Advanced metering infrastructure Transition Charges Applications 2017*, 30 August 2016, p. 4.

<sup>75</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5I.7 and 5I.7A.

<sup>76</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 36.

<sup>77</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 36.

## 5 United Energy

We do not accept United Energy's Transition Charge Application, which proposed a positive transition charge of \$1.0 million (\$2018). In place of its proposal, we have calculated a substitute transition charge.

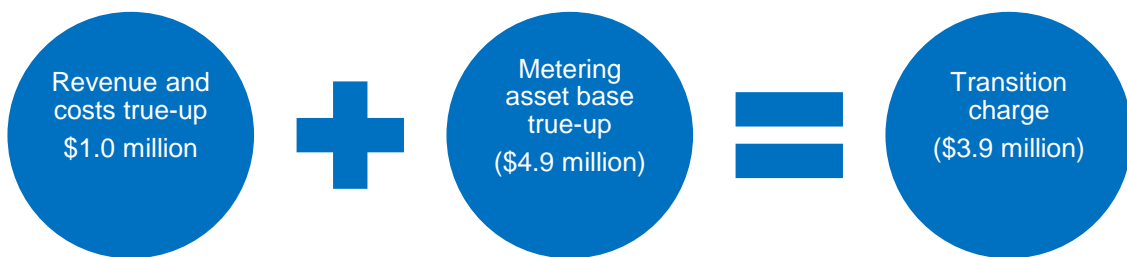
### 5.1 Draft decision

Our draft decision provides for a negative transition charge of \$3.9 million (\$2018).

Under the Order, the calculation of United Energy's transition charge must consist of a revenue and costs true-up and a MAB adjustment (see section 3.1).<sup>78</sup> United Energy's application included the revenue and costs true-up in the calculation of its proposed transition charge but did not include the MAB adjustment. We have not accepted this aspect of United Energy's proposal.

Figure 5.1 sets out the components that make up our draft decision. It shows that our draft decision transition charge consists of a positive revenue and costs true-up of \$1.0 million (\$2018) plus a negative MAB adjustment of \$4.9 million (\$2018) giving a total transition charge of negative \$3.9 million (\$2018).

**Figure 5.1 Draft decision transition charge (\$2018)**



Source: AER analysis.

#### 5.1.1 Revenue and costs true-up

We have calculated a positive revenue and costs true-up of \$1.0 million (\$2018).

In making our draft decision, we have accepted United Energy's proposal to recover \$25.3 million (\$2018) in proposed 2014 and 2015 excess expenditure.

With respect to the revenue and costs true-up of the transition charge, the only difference between our draft decision and United Energy's proposal is the year in which we have determined the transition charge will apply.

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<sup>78</sup> Victorian Advanced Metering Infrastructure Cost Recovery Order In Council, cl 5L.4 and 5L.7 to 5L.12.

In its application, United Energy sought to apply the charge in 2017. For the reasons outlined in section 1 above, our draft decision is to apply the true-up in the 2018 year of the 2016–2020 regulatory control period. To do this, we have adjusted for the time value of money.

To calculate the revenue and costs true-up in accordance with the Order, we followed a series of steps outlined below.

### Step one

The first step we took in calculating United Energy's revenue and costs true-up was to verify the distributor's actual AMI revenue recovered from its customers over the 2009–15 period.

Table 5.1 sets out United Energy's AMI tariff revenue which we have verified against audited regulatory information notices.

**Table 5.1 AMI tariff revenue (\$m, NPV 2009)**

	2009	2010	2011	2012	2013	2014	2015	Total
Tariff revenue	17.7	40.2	48.8	51.0	54.7	57.4	60.4	330.2

Source: United Energy, 2009–15 Regulatory Information Notices.

### Step two

The next step we took was to calculate United Energy's approved building block costs or approved budget costs. When doing this, the Order provides that we are required to give consideration to a proposal (if any) to recover excess expenditure incurred in 2014 and 2015.

United Energy proposed to recover \$25.3 million (\$2018) in total excess expenditure (capex) which it incurred in 2014. We have accepted this proposal in full for the reasons outlined in section 5.2.

United Energy approved recoverable costs over the 2009–15 period are set out in Table 5.2. It shows that by accepting the full amount of proposed excess expenditure, United Energy's recoverable building block costs are the same as it proposed in its transition charge application. We convert the values in Table 5.2 from a 2009 NPV to a 2018 NPV in step four below.

**Table 5.2 Approved recoverable costs (\$m, NPV 2009)**

	2009	2010	2011	2012	2013	2014	2015	Total
United Energy's proposal	26.3	42.0	56.2	59.9	58.1	47.1	41.1	330.7
AER draft	26.3	42.0	56.2	59.9	58.1	47.1	41.1	330.7

decision			
Difference	0.0	0.0	0.0

Source: AER analysis.

### Step three

The third step we took was to calculate the difference between United Energy's revenue and approved costs. Table 5.3 sets out this calculation in 2009 NPV terms. It shows that our draft decision is the same as United Energy proposed.

**Table 5.3 Revenue and costs true-up (\$m, NPV 2009)**

	Revenue	Approved costs	True-up
United Energy's proposal	330.2	330.7	0.5
AER draft decision	330.2	330.7	0.5

Source: AER analysis.

### Step four

Our final step was to discount the true-up amount to its correct NPV.

We have decided in this draft decision to apply the transition charge in the 2018 year of the Victorian electricity distributor's 2016–2020 regulatory control period. We therefore discounted the amount we calculated in step three to its 2018 NPV.<sup>79</sup> This amount is set out in Table 5.4.

**Table 5.4 Draft decision on revenue and costs true-up (\$m, NPV 2018)**

	True-up
AER draft decision	1.0

Source: AER analysis.

## 5.1.2 MAB true-up

We have calculated a negative MAB true-up of \$4.9 million (\$2018).

### Step one

The first step we took was to recalculate the 2016–2020 opening MAB value.

<sup>79</sup> When discounting to a 2018 NPV, we used forecast CPI for the 2018 year. We also applied a forecast WACC for the 2017 and 2018 years. We will update these forecast CPI and WACC values for actuals when we apply the transition charge through our 2018 annual pricing approval processes.

This process involved a comparison. In particular, we compared the opening MAB value which we determined in our 2016–2020 distribution determination with the opening MAB value that we have calculated in this transition charges draft decision. Table 5.5 sets out that recalculation.

**Table 5.5 Calculation of opening MAB value (\$m, 2008)**

	2011	2012	2013	2014	2015	Opening MAB
2016–2020 Victorian determination	174.5	194.7	207.4	201.4	174.6	174.6
Transition charge draft decision	174.5	194.7	207.4	198.0	172.9	172.9

Source: AER analysis.

As shown in Table 5.5 above, the opening MAB value we have calculated in this transition charges draft decision is lower than in our 2016–2020 distribution determination. The reason for this is that our 2016–2020 distribution determination relied on forecast data. In particular, when determining the capex to be rolled into the MAB for the 2014 and 2015 years we used United Energy's forecast capex in its 2015 AMI Charges Revision Applications.<sup>80</sup> In effect, we used a forecast United Energy had made in August 2014, which had not been subject to a prudence assessment.

Our transition charge draft decision, by contrast, takes United Energy's *actual* capex in 2014 and 2015 into consideration. We have also considered a proposal from United Energy to recover excess capex in the 2014 and 2015 years. With respect to this, we have only rolled into our recalculation of the MAB, any excess capex that we consider to be prudent. Our reasons regarding this prudence assessment are outlined in section 5.2 below.

### Step two

Once we had recalculated United Energy's MAB value, the next step we took was to escalate the value of the recalculated MAB value to 2015 dollar terms.

The reason why we escalated it to 2015 dollar terms was that this is the value which we applied in our 2016–2020 distribution determination. Table 5.6 sets out the results of the escalation we applied.

**Table 5.6 Recalculation of opening MAB value**

	(\$m, 2008)	(\$m, 2015)
Opening MAB as of 1 January 2016	172.9	210.3

<sup>80</sup> 2015 AMI charges revision application, August 2014.

Source: AER analysis.

### Step three

The next step we took was to compare the revenue recoverable from the opening MAB we set our 2016–2020 distribution determination with our recalculation of the MAB in this transition charge draft decision. Table 5.7 sets out the results of this comparison.

**Table 5.7 Recalculation of MAB revenue (\$million)**

	2016 (\$nominal)	2017 (\$nominal)	2018 (\$nominal)	2019 (\$nominal)	2020 (\$nominal)	Total (\$Dec 2015)
2016–2020 Victorian determination	37.4	37.1	36.7	26.2	22.2	135.2
Transition charge draft decision	36.7	36.4	36.0	24.1	21.4	131.1
Difference						(4.1)

Source: AER analysis.

### Step four

The final step we took to calculate the MAB adjustment was to discount the revenue difference calculated in step 3 to its 2018 NPV.<sup>81</sup> When we did this, we calculated a negative MAB adjustment of \$4.9 million (\$2018).

## 5.2 Reasons for draft decision

Our draft decision accepts the proposed excess expenditure included in United Energy's transition charges application. Our reasons are outlined below.

### 5.2.1 Excess capital expenditure

We accept United Energy's proposed \$25.3 million (\$2018) in excess capital expenditure for 2014. Our draft decision is that the proposed amount meets the requirements in the Order to be recovered through the transition charge.

#### *Meter supply and installation*

We accept United Energy's proposed \$7.0 million (\$2018) in excess capital expenditure for 'meter supply'. We also accept its proposed \$17.9 million (\$2018) for meter installation capex. Table 5.8 sets out our draft decision.

<sup>81</sup> When discounting to a 2018 NPV, we used forecast CPI for the 2018 year. We also applied a forecast WACC for the 2017 and 2018 years. We will update these forecast CPI and WACC values for actuals when we apply the transition charge through our 2018 annual pricing approval processes.



**Table 5.8 Draft decision on meter supply capex (\$m 2018)**

	Approved budget (2012–15 Budget)	Proposed excess	Draft decision
2014			
Meter supply	1.4	7.0	7.0
Meter installation	0.0	17.9	17.9
2015			
Meter supply	0.0	0.0	0.0
Meter installation	0.0	0.0	0.0
Total	1.4	24.9	24.9

Source: AER analysis.

In its transition charge application, United Energy proposed that its excess capital expenditure for meter supply and installation was due to delays in its AMI roll-out that were outside of its control.<sup>82</sup> United Energy noted that its original plan was that 95 percent of its AMI meters would be deployed by 31 December 2012, with the remaining 5 percent to be completed during 2013.<sup>83</sup> Under this plan, the installation of AMI meters in 2014 was not contemplated in the AER's approved budget for that year. Government policy and market condition changes, however, caused delays which led to the deployment of meters in 2014.

Energeia accepted United Energy's contention that its excess capital expenditure for meter supply and installations was due to delays outside of its control. Specifically, it characterised the expenditure as reflective of a timing as opposed to a cost variation.<sup>84</sup> Energeia also observed that overall United Energy's AMI expenditure per meter was the lowest.<sup>85</sup> It concluded that United Energy's 'overall metering capex, which includes meter supply and meter installation capex sub-categories, to be the benchmark efficient entity'.<sup>86</sup>

Our draft decision, based on Energeia's advice and our own analysis, is to accept United Energy's proposed excess capital expenditure for meter supply and installation, totalling \$24.9 million (\$2018). We are satisfied that the expenditure reflects the efficient costs of business providing AMI services which also faced the government policy and market changes United Energy experienced. In accordance with the

<sup>82</sup> United Energy, *AMI Transition Charges Application*, 31 May 2016, p. 14.

<sup>83</sup> United Energy, *AMI Transition Charges Application*, 31 May 2016, p. 14.

<sup>84</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 28.

<sup>85</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 28.

<sup>86</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 28.

Order,<sup>87</sup> we find that the expenditure is prudent and have included it in our calculation of United Energy's transition charge in this draft decision.

### ***Communications infrastructure***

We accept United Energy's proposed excess capital expenditure for AMI communications infrastructure, totalling \$0.3 million (\$2018).

In support of its application, United Energy proposed that its 2012–15 Approved Budget 'assumed that all access points and repeaters would be purchased and installed by 2012, consistent with the planned completion date of 31 December 2013 for the AMI roll-out'.<sup>88</sup> Delays nonetheless led to some additional infrastructure deployed in 2014.

Our draft decision accepts United Energy's proposal. Energeia's advice is that the proposed excess capital expenditure for AMI communications infrastructure reflects a timing variation. It further noted that United Energy is the benchmark efficient entity in terms of its AMI communications infrastructure. We have included the proposed \$0.3 million (\$2018) in our calculation of United Energy's transition charge.

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<sup>87</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5I.7 and 5I.7A.

<sup>88</sup> United Energy, *AMI Transition Charges Application*, 31 May 2016, p. 14.

## 6 Jemena

We do not accept Jemena's Transition Charge Application, which proposed a negative transition charge of \$1.7 million (\$2018). In place of its proposal, we have calculated a substitute transition charge.

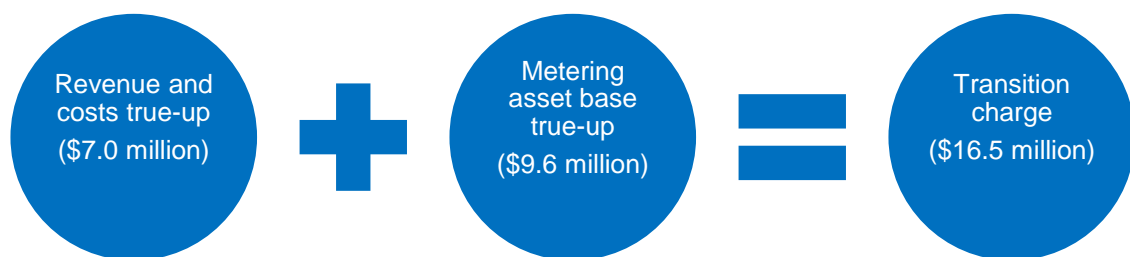
### 6.1 Draft decision

Our draft decision provides for a negative transition charge of \$16.5 million (\$2018).

Under the Order, the calculation of Jemena's transition charge must consist of a revenue and costs true-up and a MAB adjustment (see section 3.1).<sup>89</sup> Jemena's application included the revenue and costs true-up in the calculation of its proposed transition charge but did not include the MAB adjustment. We have not accepted this aspect of Jemena's proposal.

Figure 6.1 sets out the components that make up our draft decision. It shows that our draft decision transition charge consists of a negative revenue and costs true-up of negative \$7.0 million (\$2018) plus a negative MAB adjustment of \$9.6 million (\$2018) giving a total transition charge of negative \$16.5 million (\$2018).

**Figure 6.1 Draft decision transition charge (\$2018)**



Source: AER analysis.

#### 6.1.1 Revenue and costs true-up

We have calculated a negative revenue and costs true-up of \$7.0 million (\$2018).

In 2015 NPV terms, Jemena proposed a negative revenue and costs true-up of \$0.8 million (\$2015).<sup>90</sup> When discounted to a 2018 NPV this is equal to \$1.7 million (\$2018) return to customers. Our draft decision for a \$7.0 million (\$2018) true-up will therefore lead to a greater return of revenue to customers than Jemena had proposed in its application.

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<sup>89</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5L.4 and 5L.7 to 5L.12.

<sup>90</sup> Jemena, *AMI Transition Charges Application*, 31 May 2016, p. 1.

The reason for the difference between our draft decision and Jemena's proposal relates to our assessment of 2014 and 2015 excess expenditure. For the reasons set out in section 6.2, our draft decision is to accept \$7.9 million (\$2018) of Jemena's proposed \$14.8 million (\$2018) in excess expenditure.

To calculate the revenue and costs true-up in accordance with the Order, we followed a series of steps outlined below.

### Step one

The first step we took in calculating Jemena's revenue and costs true-up was to verify the distributor's actual AMI revenue recovered from customers over the 2009–15 period.

Table 6.1 sets out Jemena's AMI tariff revenue which we have verified against audited regulatory information notices.

**Table 6.1 AMI tariff revenue (\$m, NPV 2009)**

	2009	2010	2011	2012	2013	2014	2015	Total
Tariff revenue	10.3	37.0	34.7	35.7	37.4	39.7	43.9	238.6

Source: United Energy, 2009–15 Regulatory Information Notices.

### Step two

The next step we took was to calculate Jemena's approved building block costs or approved budget costs. When doing this, the Order provides that we are required to give consideration to a proposal (if any) to recover excess expenditure incurred in 2014 and 2015.

Jemena proposed to recover \$14.8 million (\$2018) in total excess expenditure which it incurred in 2014 and 2015 (capex and opex). Of this amount, our draft decision accepts \$7.9 million (\$2018). Our reasons are set out in section 6.2.

The revenue impact of our draft decision to accept less excess expenditure than Jemena proposed is set out in Table 6.2. It shows that by not accepting the full amount of excess expenditure, Jemena's recoverable building block costs are lower than proposed. We convert the values in Table 6.2 from a 2009 NPV to a 2018 NPV in step four below.

**Table 6.2 Approved recoverable costs (\$m, NPV 2009)**

	2009	2010	2011	2012	2013	2014	2015	Total
Jemena's proposal	28.5	30.1	37.5	39.6	39.0	33.6	29.4	237.8
AER draft decision	28.5	30.1	37.5	39.6	39.0	30.8	29.7	235.2

Difference	(2.8)	0.3 <sup>(a)</sup>	(2.6)
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Source: AER analysis.

- (a) Our draft decision accepts higher recoverable building block costs than proposed as a result of our calculation of Jemena's tax liability. In 2015, we have substituted Jemena's proposed building block tax liability of \$0.3 million (\$nominal) with \$2.7 million (\$nominal). We have made this substitution because Jemena will have access to lower tax deductions as a consequence of us accepting less excess capital expenditure in this draft decision than was proposed. In terms of revenue, this increases Jemena's approved recoverable costs by \$0.3 million (NPV 2009) in 2015.

### Step three

The third step we took was to calculate the difference between Jemena's revenue and approved costs. Table 6.3 sets out this calculation in 2009 NPV terms.

**Table 6.3 Revenue and costs true-up (\$m, NPV 2009)**

	Revenue	Approved costs	True-up
United Energy's proposal	238.6	237.8	(0.8)
AER draft decision	238.6	235.2	(3.4)

Source: AER analysis.

### Step four

Our final step was to discount the true-up amount to its correct NPV.

We have decided in this draft decision to apply the transition charge in the 2018 year of the Victorian electricity distributor's 2016–2020 regulatory control period. We therefore discounted the amount we calculated in step three to its 2018 NPV.<sup>91</sup> This amount is set out in Table 6.4.

**Table 6.4 Draft decision on revenue and costs true-up (\$m, NPV 2018)**

	True-up
AER draft decision	(7.0)

Source: AER analysis.

## 6.1.2 MAB true-up

We have calculated a negative MAB true-up of \$9.6 million (\$2018).

<sup>91</sup> When discounting to a 2018 NPV, we used forecast CPI for the 2018 year. We also applied a forecast WACC for the 2017 and 2018 years. We will update these forecast CPI and WACC values for actuals when we apply the transition charge through our 2018 annual pricing approval processes.

## Step one

The first step we took was to recalculate the 2016–2020 opening MAB value.

This process involved a comparison. In particular, we compared the opening MAB value which we determined in our 2016–2020 distribution determination with the opening MAB value that we have calculated in this transition charges draft decision. Table 6.9 sets out that recalculation.

**Table 6.5 Calculation of opening MAB value (\$m, 2008)**

	2011	2012	2013	2014	2015	Opening MAB
2016–2020 Victorian determination	109.0	111.6	118.0	111.3	98.5	98.5
Transition charge draft decision	109.0	111.6	118.0	107.7	90.3	90.3

Source: AER analysis.

As shown in Table 6.5 above, the opening MAB value we have calculated in this transition charges draft decision is lower than in our 2016–2020 distribution determination. The reason for this is that our 2016–2020 distribution determination relied on forecast data. In particular, when determining the capex to be rolled into the MAB for the 2014 and 2015 years we used Jemena's forecast capex in its 2015 AMI Charges Revision Applications.<sup>92</sup> In effect, we used a forecast Jemena had made in August 2014, which had not been subject to a prudence assessment.

Our transition charge draft decision, by contrast, takes Jemena's *actual* capex in 2014 and 2015 into consideration. We have also considered a proposal from Jemena to recover excess capex in the 2014 and 2015 years. With respect to this, we have only rolled into our recalculation of the MAB, any excess capex that we consider to be prudent. Our reasons regarding this prudence assessment are outlined in section 6.2 below.

## Step two

Once we had recalculated Jemena's MAB value, the next step we took was to escalate the value of the recalculated MAB value to 2015 dollar terms.

The reason why we escalated it to 2015 dollar terms was that this is the value which we applied in our 2016–2020 distribution determination. Table 6.6 sets out the results of the escalation we applied.

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<sup>92</sup> 2015 AMI charges revision application, August 2014.

**Table 6.6 Recalculation of opening MAB value**

	(\$m, 2008)	(\$m, 2015)
Opening MAB as of 1 January 2016	90.3	109.8

Source: AER analysis.

### Step three

The next step we took was to compare the revenue recoverable from the opening MAB we set our 2016–2020 distribution determination with our recalculation of the MAB in this transition charge draft decision. Table 6.7 sets out the results of this comparison.

**Table 6.7 Recalculation of MAB revenue (\$million)**

	2016 (\$nominal)	2017 (\$nominal)	2018 (\$nominal)	2019 (\$nominal)	2020 (\$nominal)	Total (\$Dec 2015)
2016–20 Victorian determination	23.9	22.5	16.4	16.3	15.6	80.1
Transition charge draft decision	21.7	21.5	15.2	14.5	11.7	72.0
Difference						(8.1)

Source: AER analysis.

### Step four

The final step we took to calculate the MAB adjustment was to discount the revenue difference calculated in step 3 to its 2018 NPV.<sup>93</sup> When we did this, we calculated a negative MAB adjustment of \$9.6 million (\$2018).

## 6.2 Reasons for draft decision

Our draft decision does not accept the proposed excess capital and operating expenditure included in Jemena's transition charges application. Our reasons are outlined below.

### 6.2.1 Excess capital expenditure

We accept \$7.6 million (\$2018) of Jemena's proposed excess capital expenditure for 2014 and 2015 is prudent. This amounts to approximately 62 percent of the 12.3 million (\$2018) Jemena sought to recover. Our draft decision is that this amount meets

<sup>93</sup> When discounting to a 2018 NPV, we used forecast CPI for the 2018 year. We also applied a forecast WACC for the 2017 and 2018 years. We will update these forecast CPI and WACC values for actuals when we apply the transition charge through our 2018 annual pricing approval processes.

the requirements in the Order to be recovered through the transition charge. Each of Jemena's excess capital expenditure categories are considered below.

### ***Meter supply***

We accept \$1.6 million (\$2018) in excess capital expenditure for 'meter supply'. This is the full amount that Jemena sought to recover for additional metering units. Table 6.8 sets out our draft decision.

**Table 6.8 Draft decision on meter supply capex (\$m 2018)**

	Approved budget (2012–15 Budget)	Proposed excess	Draft decision
2014	1.1	2.8	2.8
2015	1.2	(1.1)	(1.1)
Total	2.3	1.6	1.6

Source: AER analysis.

Jemena proposed that its excess capital expenditure for meter supply was due to delays in its AMI roll-out that were outside of its control.<sup>94</sup> We accept that there were government policy and market changes which would have caused delays. This is consistent with our draft decision for both AusNet Services and United Energy.<sup>95</sup> We also note that benchmarking conducted by Energeia observed that Jemena's 2009–15 meter supply capex was reasonably efficient (see section 9). We accordingly accept Jemena's proposed meter supply capex of \$1.6 million (\$2018).

### ***Meter installation***

We accept \$4.8 million (\$2018) in excess capital expenditure for 'meter installation'. This is equal to about 58 percent of Jemena's proposed \$8.2 million (\$2018) in excess capital expenditure for installing meters in 2014 and 2015. Table 6.9 sets out our draft decision.

**Table 6.9 Draft decision on meter installation capex (\$m 2018)**

	Approved budget (2012–15 Budget)	Proposed excess	Draft decision
2014	0.0	8.0	4.5
2015	0.0	0.3	0.3
Total	0.0	8.2	4.8

<sup>94</sup> Jemena, *AMI Transition Charges Application*, 31 May 2016, p. 30.

<sup>95</sup> See sections 4 and 5 of this draft decision.



Source: AusNet Services, AMI Transition Charges Application, 31 May 2016, p. 23 and p. 27.

In its application, Jemena submitted that its proposed excess capital expenditure for meter installations should be accepted because:

- the expenditure is driven by a timing variation
- Jemena's unit rates for meter installations are efficient.<sup>96</sup>

We accept that the proposed excess capital expenditure for meter installations is, in part, driven by a timing variation. Our draft decision has reached this conclusion on the basis that changes to government policy and market conditions would have pushed out the installation of meters in 2014 and 2015 which Jemena had initially scheduled to install earlier.

We do not, however, accept that Jemena's unit rates for meter installations are efficient. Energeia found that Jemena's unit costs for installations were above the efficient benchmark.<sup>97</sup> This analysis is set out in section 9. Energeia's review found that Jemena's overall meter installation capex was \$46 million (\$2018) more than the efficient benchmark comparator, United Energy. Table 6.10 also shows that Energeia found that Jemena's installation unit costs were materially higher than United Energy.

**Table 6.10 Comparison of installation unit costs (\$ 2018)**

	Jemena	United Energy	Difference
2014 installation unit cost	277	137	140
2015 installation unit cost	222	142	80

Source: Energeia, Review of 2017 AMI transition applications, August 2016, p. 28.

Based on Energeia's analysis, we accept an excess capital expenditure for meter installations of \$4.8 million (\$2018). In calculating this amount, we have accepted the proposed volume of installations in Jemena's application, which total 2 672 in 2014 and 1 103 in 2015. This is in recognition that government policy and market conditions did lead to Jemena having to install meters in 2014 and 2015. However, we have not accepted the unit rates Jemena included in its application. In its place, we used United Energy's installation unit rates. By doing this, we consider the excess expenditure to reasonably reflect, as required under the Order, the efficient costs of a business providing AMI services.<sup>98</sup>

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<sup>96</sup> Jemena, *AMI Transition Charges Application*, 31 May 2016, p. 30.

<sup>97</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 29.

<sup>98</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5I.7 and 5I.7A.

### ***Back office capex***

We accept \$1.2 million (\$2018) in excess capital expenditure for additional back office activities incurred in 2014. This is equal to about 45 percent of Jemena's proposed \$2.4 million (\$2018) excess expenditure for this cost category.

The Victorian Government raised concerns about the extent of the customer service and project management office expenditure excess.<sup>99</sup>

Our draft decision accepts that Jemena would have incurred additional back office capex activities in 2014. However, we do not accept the unit costs making up those activities. Instead, we have applied the unit costs, updated for labour costs escalation, we accepted for Jemena in our 2012–15 Approved Budget. This is consistent with the advice we received from Energeia.<sup>100</sup>

Applying our substitute unit costs to the volume of back office activities incurred in 2014 we calculated an excess capital expenditure of \$1.2 million (\$2018). We consider this amount to reflect the costs of a business providing AMI services, as required under the Order.<sup>101</sup>

### **6.2.2 Excess operating expenditure**

We accept \$0.3 million (\$2018) in excess operating expenditure for additional meter data activities incurred in 2014 and 2015. This is equal to about 16 percent of Jemena's proposed \$2.5 million (\$2018).

In its application, Jemena stated that the excess operating expenditure for this category was driven by:

- higher manual metering costs than forecast
- higher back office system operating costs for processing and handling of accumulation and manually read interval data.<sup>102</sup>

Energeia conducted a review of Jemena's meter data opex. It found that Jemena's opex for this category was the highest of all Victorian distributors and more than double United Energy's expenditure, which Energeia identified as the efficient benchmark. See section 9 of this draft decision for more information.

Given Energeia's benchmarking analysis, we do not consider Jemena's proposed excess operating expenditure for meter data to reasonably reflect, as required, the costs of an efficient business providing AMI services.<sup>103</sup> Our draft decision accepts \$0.3 million (\$2018) in excess expenditure for manual meter reading. Jemena had an

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<sup>99</sup> Department of Environment, Land, Water & Planning, Submission on Advanced metering infrastructure Transition Charges Applications 2017, 30 August 2016, p. 4.

<sup>100</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 30.

<sup>101</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5I.7 and 5I.7A.

<sup>102</sup> Jemena, *AMI Transition Charges Application*, 31 May 2016, p. 32.

<sup>103</sup> *Victorian Advanced Metering Infrastructure Cost Recovery Order In Council*, cl 5I.7 and 5I.7A.

obligation to continue to read meters for customers who had refused to provide access for installing a smart meters, but to do so efficiently. This allowance covers the efficient costs incurred by Jemena up until the separate manual meter charge was introduced in April 2015. This is consistent with the advice we received from Energeia based on an efficient unit cost and volume of installations.<sup>104</sup>

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<sup>104</sup> Energeia, Review of 2017 AMI transition applications, August 2016, pp. 27–28.

## 7 CitiPower

We do not accept CitiPower's Transition Charge Application.

The only difference between CitiPower's proposal and our draft decision is the year in which the charge will apply. CitiPower proposed that the charge should apply in 2017 but our draft decision is that this will apply in 2018.

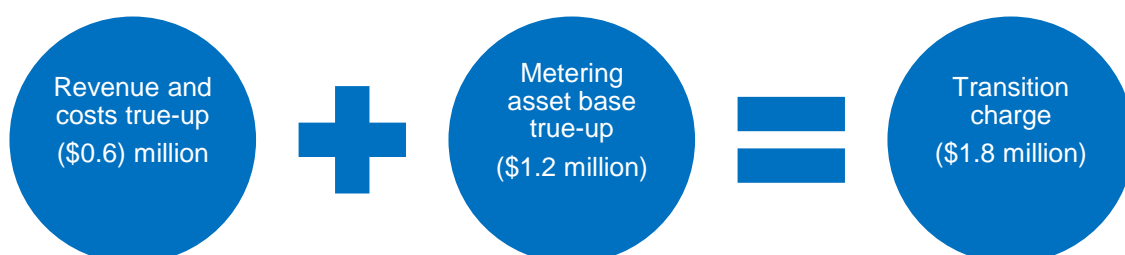
### 7.1 Draft decision

Our draft decision provides for a negative transition charge of \$1.8 million (\$2018).

Unlike other applications we received,<sup>105</sup> CitiPower's proposed transition charge included both a revenue and cost true-up and a MAB adjustment. We have, however, not accepted the value of the true-up adjustments which CitiPower included in its application.

Figure 5.1 sets out the components that make up our draft decision. It shows that our draft decision transition charge consists of a negative revenue and costs true-up of \$0.6 million (\$2018) plus a negative MAB adjustment of \$1.2 million (\$2018) giving a total transition charge of negative \$1.8 million (\$2018).

**Figure 7.1 Draft decision transition charge (\$2018)**



Source: AER analysis.

#### 7.1.1 Revenue and costs true-up

We have calculated a negative revenue and costs true-up of \$0.6 million (\$2018).

With respect to the revenue and costs true-up of the transition charge, the key difference between our draft decision and CitiPower's proposal is the year in which we have determined the transition charge will apply. CitiPower underspent its 2014 and 2015 budget and therefore did not apply to recover excess expenditure.

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<sup>105</sup> AusNet Services, Jemena and United Energy did not include a MAB true-up in their calculations.

In its application, CitiPower sought to apply the charge in 2017. For the reasons outlined in section 1 above, our draft decision is to apply the true-up in the 2018 year of the 2016–2020 regulatory control period. This is the only difference between CitiPower's proposal and this draft decision. To do this, we have adjusted for the time value of money. Each of the steps we followed in calculating CitiPower's transition charge are outlined below.

### Step one

The first step we took in calculating CitiPower's revenue and costs true-up was to verify the distributor's actual AMI revenue recovered from its customers over the 2009–15 period.

Table 7.1 sets out CitiPower's AMI tariff revenue which we have verified against audited regulatory information notices.

**Table 7.1 AMI tariff revenue (\$m, NPV 2009)**

	2009	2010	2011	2012	2013	2014	2015	Total
Tariff revenue	11.7	28.9	23.5	23.4	28.1	24.2	20.9	160.5

Source: CitiPower, 2009–15 Regulatory Information Notices.

### Step two

The next step we took was to calculate CitiPower's approved building block costs or approved budget costs. Since CitiPower underspent its budget, this process did not require us to consider any 2014 and 2015 excess expenditure.

**Table 7.2 Approved recoverable costs (\$m, NPV 2009)**

	2009	2010	2011	2012	2013	2014	2015	Total
CitiPower's proposal	24.8	18.5	25.2	26.0	26.0	21.5	18.2	160.2
AER draft decision	24.8	18.5	25.2	26.0	26.0	21.5	18.2	160.2
Difference						0.0	0.0	0.0

Source: AER analysis.

### Step three

The third step we took was to calculate the difference between CitiPower's revenue and approved costs. Table 7.3 sets out this calculation in 2009 NPV terms. It shows that our draft decision is the same as CitiPower's proposed.

**Table 7.3 Revenue and costs true-up (\$m, NPV 2009)**

	Revenue	Approved costs	True-up
CitiPower's proposal	160.5	160.2	(0.3)
AER draft decision	160.5	160.2	(0.3)

Source: AER analysis.

### **Step four**

Our final step was to discount the true-up amount to its correct NPV.

We have decided in this draft decision to apply the transition charge in the 2018 year of the Victorian electricity distributor's 2016–2020 regulatory control period. We therefore discounted the amount we calculated in step three to its 2018 NPV.<sup>106</sup> This amount is set out in Table 7.4.

**Table 7.4 Draft decision on revenue and costs true-up (\$m, NPV 2018)**

	True-up
AER draft decision	(0.6)

Source: AER analysis.

## **7.1.2 MAB true-up**

We have calculated a negative MAB true-up of \$1.8 million (\$2018).

### **Step one**

The first step we took was to recalculate the 2016–2020 opening MAB value.

This process involved a comparison. In particular, we compared the opening MAB value which we determined in our 2016–2020 distribution determination with the opening MAB value that we have calculated in this transition charges draft decision. Table 7.5 sets out that recalculation.

**Table 7.5 Calculation of opening MAB value (\$m, 2008)**

	2011	2012	2013	2014	2015	Opening MAB
2016–2020	91.0	115.6	126.1	115.7	105.2	105.2

<sup>106</sup> When discounting to a 2018 NPV, we used forecast CPI for the 2018 year. We also applied a forecast WACC for the 2017 and 2018 years. We will update these forecast CPI and WACC values for actuals when we apply the transition charge through our 2018 annual pricing approval processes.

Victorian determination

Transition charge draft decision	91.0	115.6	126.1	114.6	103.8	103.8
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Source: AER analysis.

As shown in Table 7.5 above, the opening MAB value we have calculated in this transition charges draft decision is lower than in our 2016–2020 distribution determination. The reason for this is that our 2016–2020 distribution determination relied on forecast data. In particular, when determining the capex to be rolled into the MAB for the 2014 and 2015 years we used CitiPower's forecast capex in its 2015 AMI Charges Revision Applications.<sup>107</sup> In effect, we used a forecast CitiPower had made in August 2014, which had not been subject to a prudency assessment. Our transition charge draft decision, by contrast, takes CitiPower's *actual* capex in 2014 and 2015 into consideration.

### Step two

Once we had recalculated CitiPower's MAB value, the next step we took was to escalate the value of the recalculated MAB value to 2015 dollar terms.

The reason why we escalated it to 2015 dollar terms was that this is the value which we applied in our 2016–2020 distribution determination. Table 7.6 sets out the results of the escalation we applied.

**Table 7.6 Recalculation of opening MAB value**

	(\$m, 2008)	(\$m, 2015)
Opening MAB as of 1 January 2016	103.8	126.2

Source: AER analysis.

### Step three

The next step we took was to compare the revenue recoverable from the opening MAB we set our 2016–2020 distribution determination with our recalculation of the MAB in this transition charge draft decision. Table 7.7 sets out the results of this comparison.

**Table 7.7 Recalculation of MAB revenue (\$million)**

	2016 (\$nominal)	2017 (\$nominal)	2018 (\$nominal)	2019 (\$nominal)	2020 (\$nominal)	Total (\$Dec 2015)
2016–2020 Victorian determination	20.5	20.4	20.3	18.4	13.4	79.0

<sup>107</sup> 2015 AMI charges revision application, August 2014.

Transition charge draft decision	20.3	20.2	20.1	18.0	13.3	77.9
Difference						-1.0

Source: AER analysis.

### ***Step four***

The final step we took to calculate the MAB adjustment was to discount the revenue difference calculated in step 3 to its 2018 NPV.<sup>108</sup> When we did this, we calculated a negative MAB adjustment of \$1.8 million (\$2018).

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<sup>108</sup> When discounting to a 2018 NPV, we used forecast CPI for the 2018 year. We also applied a forecast WACC for the 2017 and 2018 years. We will update these forecast CPI and WACC values for actuals when we apply the transition charge through our 2018 annual pricing approval processes.



## 8 Powercor

We do not accept Powercor's Transition Charge Application.

The only difference between Powercor's proposal and our draft decision is the year in which the charge will apply. Powercor proposed that the charge should apply in 2017 but our draft decision is that this will apply in 2018.

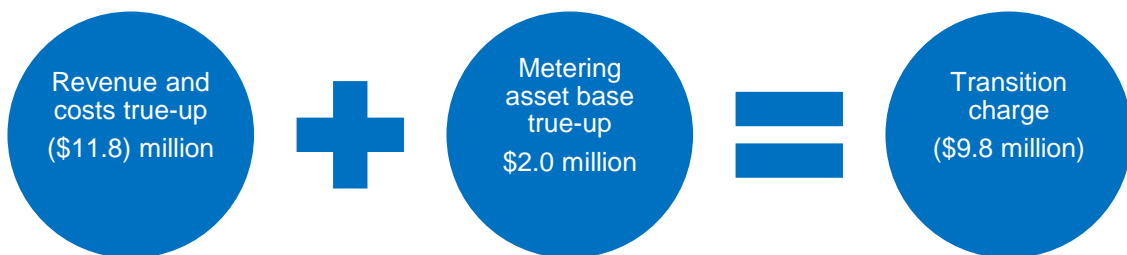
### 8.1 Draft decision

Our draft decision provides for a negative transition charge of \$9.8 million (\$2018).

Unlike other applications we received,<sup>109</sup> Powercor's proposed transition charge included both a revenue and cost true-up and a MAB adjustment. We have, however, not accepted the value of the true-up adjustments which Powercor included in its application.

Table 8.1 sets out the components that make up our draft decision. It shows that our draft decision transition charge consists of a negative revenue and costs true-up of \$11.8 million (\$2018) plus a positive MAB adjustment of \$2.0 million (\$2018) giving a total transition charge of negative \$9.8 million (\$2018).

**Figure 8.1 Draft decision transition charge (\$2018)**



Source: AER analysis.

#### 8.1.1 Revenue and costs true-up

We have calculated a negative revenue and costs true-up of \$11.8 million (\$2018).

With respect to the revenue and costs true-up of the transition charge, the key difference between our draft decision and Powercor's proposal is the year in which we have determined the transition charge will apply. Powercor underspent its 2014 and 2015 budget and therefore did not apply to recover excess expenditure.

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<sup>109</sup> AusNet Services, Jemena and United Energy did not include a MAB true-up in their calculations.

In its application, Powercor sought to apply the charge in 2017. For the reasons outlined in section 1 above, our draft decision is to apply the true-up in the 2018 year of the 2016–2020 regulatory control period. This is the only difference between Powercor's proposal and this draft decision. To do this, we have adjusted for the time value of money. Each of the steps we followed in calculating Powercor's transition charge are outlined below.

### Step one

The first step we took in calculating Powercor's revenue and costs true-up was to verify the distributor's actual AMI revenue recovered from its customers over the 2009–15 period.

Table 8.1 sets out Powercor's AMI tariff revenue which we have verified against audited regulatory information notices.

**Table 8.1 AMI tariff revenue (\$m, NPV 2009)**

	2009	2010	2011	2012	2013	2014	2015	Total
Tariff revenue	31.3	62.1	57.3	57.1	66.1	56.4	47.9	378.2

Source: Powercor, 2009–15 Regulatory Information Notices.

### Step two

The next step we took was to calculate Powercor's approved building block costs or approved budget costs. Since Powercor underspent its budget, this process did not require us to consider any 2014 and 2015 excess expenditure.

**Table 8.2 Approved recoverable costs (\$m, NPV 2009)**

	2009	2010	2011	2012	2013	2014	2015	Total
Powercor's proposal	61.6	38.9	55.0	59.8	63.6	49.7	43.9	372.4
AER draft decision	61.6	38.9	55.0	59.8	63.6	49.7	43.9	372.4
Difference						0.0	0.0	0.0

Source: AER analysis.

### Step three

The third step we took was to calculate the difference between Powercor's revenue and approved costs. Table 8.3 sets out this calculation in 2009 NPV terms. It shows that our draft decision is the same as Powercor's proposed.

**Table 8.3 Revenue and costs true-up (\$m, NPV 2009)**

	Revenue	Approved costs	True-up
CitiPower's proposal	378.2	372.4	(5.8)
AER draft decision	378.2	372.4	(5.8)

Source: AER analysis.

### **Step four**

Our final step was to discount the true-up amount to its correct NPV.

We have decided in this draft decision to apply the transition charge in the 2018 year of the Victorian electricity distributor's 2016–2020 regulatory control period. We therefore discounted the amount we calculated in step three to its 2018 NPV.<sup>110</sup> This amount is set out in Table 8.4.

**Table 8.4 Draft decision on revenue and costs true-up (\$m, NPV 2018)**

	True-up
AER draft decision	(11.8)

Source: AER analysis.

## **8.1.2 MAB true-up**

We have calculated a positive MAB true-up of \$2.0 million (\$2018).

### **Step one**

The first step we took was to recalculate the 2016–2020 opening MAB value.

This process involved a comparison. In particular, we compared the opening MAB value which we determined in our 2016–2020 distribution determination with the opening MAB value that we have calculated in this transition charges draft decision. Table 8.5 sets out that recalculation.

**Table 8.5 Calculation of opening MAB value (\$m, 2008)**

	2011	2012	2013	2014	2015	Opening MAB
2016–2020	222.9	292.5	321.4	298.7	273.1	273.1

<sup>110</sup> When discounting to a 2018 NPV, we used forecast CPI for the 2018 year. We also applied a forecast WACC for the 2017 and 2018 years. We will update these forecast CPI and WACC values for actuals when we apply the transition charge through our 2018 annual pricing approval processes.

Victorian determination

Transition charge draft decision	222.9	292.5	321.4	302.2	275.9	275.9
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Source: AER analysis.

As shown in Table 8.5 above, the opening MAB value we have calculated in this transition charges draft decision is higher than in our 2016–2020 distribution determination. The reason for this is that our 2016–2020 distribution determination relied on forecast data. In particular, when determining the capex to be rolled into the MAB for the 2014 and 2015 years we used Powercor's forecast capex in its 2015 AMI Charges Revision Applications.<sup>111</sup> In effect, we used a forecast Powercor had made in August 2014. Our transition charge draft decision, by contrast, takes Powercor's *actual* capex in 2014 and 2015 into consideration.

### Step two

Once we had recalculated Powercor's MAB value, the next step we took was to escalate the value of the recalculated MAB value to 2015 dollar terms.

The reason why we escalated it to 2015 dollar terms was that this is the value which we applied in our 2016–2020 distribution determination. Table 8.6 sets out the results of the escalation we applied.

**Table 8.6 Recalculation of opening MAB value**

	(\$m, 2008)	(\$m, 2015)
Opening MAB as of 1 January 2016	275.9	335.5

Source: AER analysis.

### Step three

The next step we took was to compare the revenue recoverable from the opening MAB we set our 2016–2020 distribution determination with our recalculation of the MAB in this transition charge draft decision. Table 8.7 sets out the results of this comparison.

**Table 8.7 Recalculation of MAB revenue (\$million)**

	2016 (\$nominal)	2017 (\$nominal)	2018 (\$nominal)	2019 (\$nominal)	2020 (\$nominal)	Total (\$Dec 2015)
2016–2020 Victorian determination	52.3	52.0	51.7	47.3	35.4	202.4

<sup>111</sup> 2015 AMI charges revision application, August 2014.

Transition charge draft decision	52.7	52.5	51.8	47.8	35.8	204.1
Difference						1.7

Source: AER analysis.

### ***Step four***

The final step we took to calculate the MAB adjustment was to discount the revenue difference calculated in step 3 to its 2018 NPV.<sup>112</sup> When we did this, we calculated a negative MAB adjustment of \$2.0 million (\$2018).

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<sup>112</sup> When discounting to a 2018 NPV, we used forecast CPI for the 2018 year. We also applied a forecast WACC for the 2017 and 2018 years. We will update these forecast CPI and WACC values for actuals when we apply the transition charge through our 2018 annual pricing approval processes.

## 9 Benchmarking

In this section, we outline Energeia's benchmarking results.

### 9.1 Review approach

The key steps Energeia undertook in performing its benchmarking included:

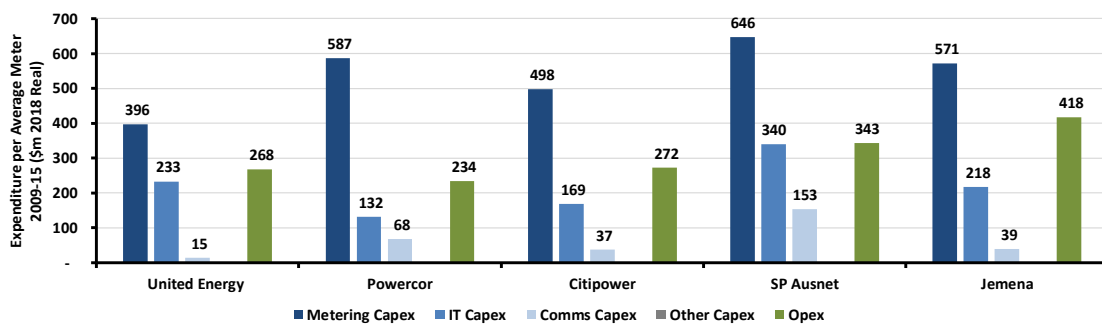
- reviewing each distributors Transition Charges Application and supporting materials
- developing questions to help clarify or supplement information provided by the distributors
- undertaking independent research, analysis and modelling as required
- developing an independent estimate of the benchmark efficient level of expenditure for each expenditure category and DNSP based on key contextual factors set out in the Order.

Energeia also stated that its review included determining 'efficient levels of excess expenditure where it was less than our estimate of benchmark efficiency levels, adjusted for key contextual differences'.<sup>113</sup>

### 9.2 Category level benchmarking

Energeia's category level benchmarking results are set out in Figure 9.1.

**Figure 9.1 Average expenditure per meter over 2009–15 (\$2018)**



Source: Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 3.

### 9.3 Sub-category level benchmarking

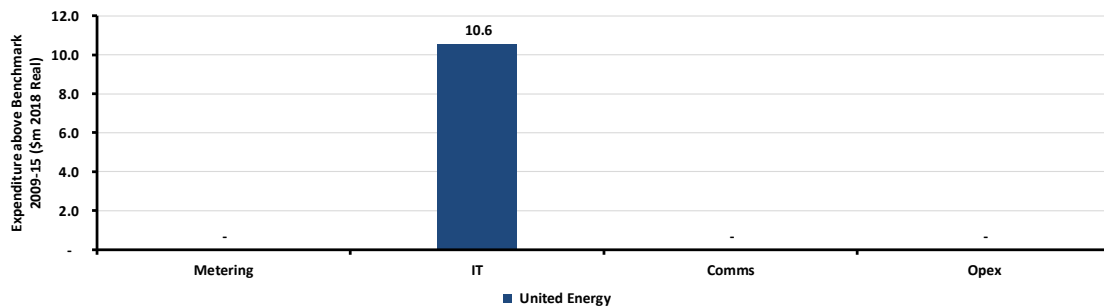
Energeia developed specific sub-category benchmark estimates. Its report notes that these 'sub-categories included meter installation, rollout completion timeframes, and several opex sub-categories'.<sup>114</sup>

<sup>113</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 3.

### 9.3.1 United Energy

In its report, Energeia states that 'all of [United Energy's] excess expenditure was found to be efficient under the [Order]'. It states that this was 'mainly due to our finding that they represent the efficient benchmark entity overall, and in the metering and communications capex sub-categories, which were also their excess expenditure sub-categories'. Figure 9.2 shows the results of Energeia's analysis.

**Figure 9.2 United Energy's expenditure above the benchmark efficient entity in 2009–15 by category (\$2018)**

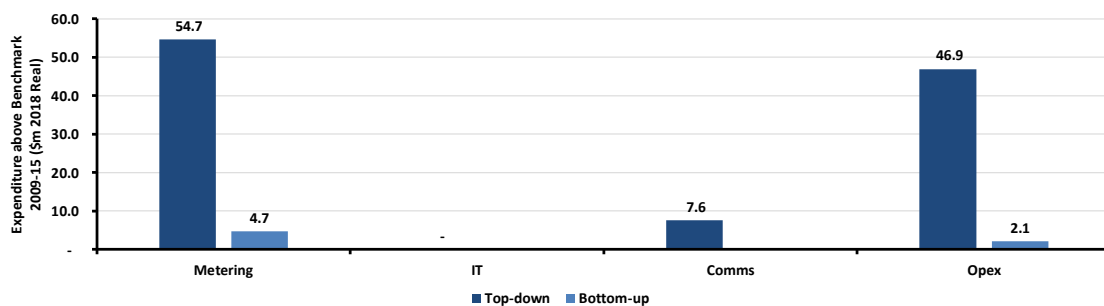


Source: Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 4.

### 9.3.2 Jemena

The sub-category level benchmarking Energeia conducted for Jemena is set out in Figure 9.3. For Jemena, Energeia considered United Energy to be the benchmark efficient entity. This was 'for each capex and opex category, except for IT, where Jemena set the efficient benchmark'.<sup>115</sup>

**Figure 9.3 Jemena's expenditure above the benchmark efficient entity in 2009–15 by category (\$2018)**



Source: Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 4.

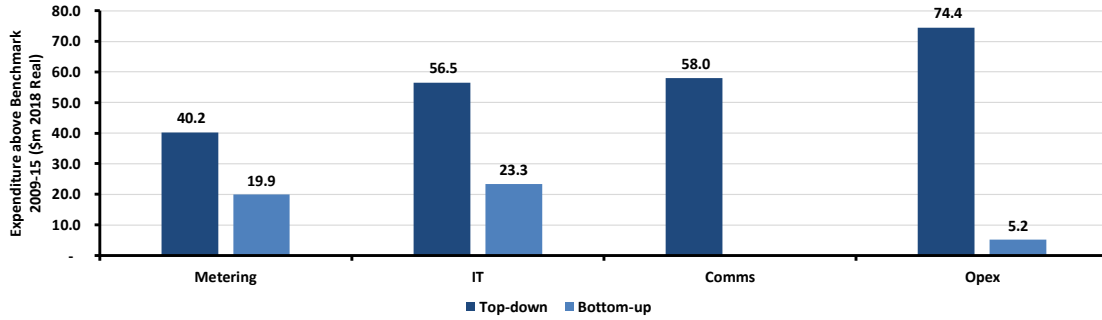
<sup>114</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 3.

<sup>115</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 3.

### 9.3.3 AusNet Services

Figure 9.4 sets out the sub–category level benchmarking included in Energeia's report. Energeia stated that it used 'Powercor as the benchmark efficient entity for [AusNet Services] except for IT capex, where Powercor and CitiPower were combined to take a more conservative position'.<sup>116</sup>

**Figure 9.4 AusNet Services' expenditure above the benchmark efficient entity in 2009–15 by category (\$2018)**



<sup>116</sup> Energeia, *Review of 2017 AMI transition applications*, August 2016, p. 3.