



**FINAL DECISION**  
**ActewAGL distribution**  
**determination**  
**2015–16 to 2018–19**

**Attachment 16 – Alternative**  
**control services**

April 2015

© Commonwealth of Australia 2015

This work is copyright. In addition to any use permitted under the Copyright Act 1968, all material contained within this work is provided under a Creative Commons Attributions 3.0 Australia licence, with the exception of:

- the Commonwealth Coat of Arms
- the ACCC and AER logos
- any illustration, diagram, photograph or graphic over which the Australian Competition and Consumer Commission does not hold copyright, but which may be part of or contained within this publication. The details of the relevant licence conditions are available on the Creative Commons website, as is the full legal code for the CC BY 3.0 AU licence.

Requests and inquiries concerning reproduction and rights should be addressed to the:

Director, Corporate Communications  
Australian Competition and Consumer Commission  
GPO Box 4141, Canberra ACT 2601

or [publishing.unit@acc.gov.au](mailto:publishing.unit@acc.gov.au).

Inquiries about this publication should be addressed to:

Australian Energy Regulator  
GPO Box 520  
Melbourne Vic 3001

Tel: (03) 9290 1444

Fax: (03) 9290 1457

Email: [AERInquiry@aer.gov.au](mailto:AERInquiry@aer.gov.au)

AER reference: 52254

## Note

This attachment forms part of the AER's final decision on ActewAGL's revenue proposal 2015–19. It should be read with other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 - Annual revenue requirement

Attachment 2 - Regulatory asset base

Attachment 3 - Rate of return

Attachment 4 - Value of imputation credits

Attachment 5 - Regulatory depreciation

Attachment 6 - Capital expenditure

Attachment 7 - Operating expenditure

Attachment 8 - Corporate income tax

Attachment 9 - Efficiency benefit sharing scheme

Attachment 10 - Capital expenditure sharing scheme

Attachment 11 - Service target performance incentive scheme

Attachment 12 - Demand management incentive scheme

Attachment 13 - Classification of services

Attachment 14 - Control mechanism

Attachment 15 - Pass through events

Attachment 16 - Alternative control services

Attachment 17 - Negotiated services framework and criteria

Attachment 18 - Connection policy

Attachment 19 - Pricing methodology

Attachment 20 - Financeability

# Contents

<b>Note</b> .....	<b>16-2</b>
<b>Contents</b> .....	<b>16-3</b>
<b>Shortened forms</b> .....	<b>16-4</b>
<b>16 Alternative control services</b> .....	<b>16-6</b>
<b>16.1 Ancillary network services</b> .....	<b>16-6</b>
16.1.1 Final decision .....	16-6
16.1.2 ActewAGL's revised proposal.....	16-10
16.1.3 Assessment approach.....	16-11
16.1.4 Reasons for final decision .....	16-12
<b>16.2 Metering</b> .....	<b>16-21</b>
16.2.1 Final decision .....	16-22
16.2.2 ActewAGL's revised proposal.....	16-27
16.2.3 Assessment approach.....	16-31
16.2.4 Reasons for final decision .....	16-36
<b>A Appendix</b> .....	<b>16-56</b>
<b>A.1 Final Decision charges for alternative control services</b> .....	<b>16-56</b>
A.1.1 Ancillary network service charges .....	16-56
A.1.2 Metering.....	16-61

## Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
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
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
repex	replacement expenditure
RFM	roll forward model

Shortened form	Extended form
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

## 16 Alternative control services

Alternative control services are those that are provided by distributors to specific customers. They do not form part of the distribution use of system revenue allowance provide by us to each distributor. Rather, distributors recover the costs of providing alternative control services through a selection of fees, most of which are charged on a 'user pays' basis.

This section describes the AER's determination on the charges that distributors can levy customers for the provision of ancillary network services and metering.

### 16.1 Ancillary network services

Ancillary network services are non-routine services provided to individual customers on an 'as needs' basis. They comprise less than four per cent of ActewAGL's total revenue requirement.

In the 2009–14 regulatory control period, we classified ancillary network services as standard control services. ActewAGL named them 'miscellaneous' services and 'monopoly' services. The fees and labour rates for these services were originally set by the jurisdictional regulator and the fees indexed only by inflation. This is the first time these fees have been reviewed in detail.

For the avoidance of doubt, this final decision considers ancillary network services to be fee based services. That is, a fee has been determined based on the cost of providing the service (labour rates) and the average time taken to perform it. The fee is fixed—it applies irrespective of the actual time taken on site to perform the service.

By contrast, quoted services are those which are once off and specific to a particular customer's request. The cost of this service will depend on the actual time taken to perform the service.<sup>1</sup>

#### 16.1.1 Final decision

For the most part we have approved ActewAGL's revised proposed 2015–16 charges for fee based ancillary network services, because the proposed service charges reflect efficient costs.

We rejected only one of ActewAGL's revised proposed labour rates (office support service delivery) for ancillary network services. Consequently, we rejected ActewAGL's revised proposed 2015–16 fees for the following three services:

- meter test (CT/VT)—business hours

---

<sup>1</sup> This is analogous to engaging a plumber to fix drainage problems in a house. The plumber's hourly rate is known in advance but the time taken to perform the fix is variable and will determine the final bill.

- special meter read
- metering transfer admin fee (transfer to another metering provider).

We do not approve ActewAGL's labour rates for fee based and quoted ancillary network services. Our final decision for maximum labour rates (including on costs, but not overheads) is set out in Table 16.1.

Because we do not approve the escalation to labour rates applied by ActewAGL's revised regulatory proposal—substituting it instead with those in in Table 16.1—we consequently do not approve any proposed fees for the remaining years of the regulatory control period. Our final decision on labour escalation is set out in Attachment 7 (operating expenditure).

**Table 16.1: Final decision labour escalation factor (percentage)**

	2015–16	2016–17	2017–18	2018–19
labour escalation factor	-0.76	-1.13	-1.22	-1.22

Source: AER analysis.

Note: The exceptions single phase, single element manually read interval meter; single phase two element meter and three phase meter. All these have an X factor of zero. To be clear, labour escalators themselves are positive for each year of the regulatory control period. However, the labour escalators in this table are operating as de facto X factors. Therefore, they are negative.

Appendix A.1.1 sets out our final decision for maximum charges to apply for ancillary network services.

### Form of control—fee based services

We apply a price cap as the form of control for fee based services.<sup>2</sup> Under this form of control a schedule of prices is set for the first year. For the following years, the previous year's prices are adjusted by CPI and an X factor. Our final decision X factors are set out in appendix A.1.

Mathematically, the form of control for fee based ancillary network services is:

---

<sup>2</sup> AER, *Stage 1 Framework and Approach Paper ActewAGL: Transitional regulatory control period 1 July 2014 to 30 June 2015 Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March 2013, pp.39-42.



## Figure 16.1 Fee based ancillary network services formula

$$\bar{p}_i^t \geq p_i^t \quad i=1,\dots,n \text{ and } t=1,\dots,4,$$

$$\bar{p}_i^t = \bar{p}_i^{t-1}(1 + \Delta CPI_t)(1 - X_i^t)$$

Where:

$\bar{p}_i^t$  is the cap on the price of service  $i$  in year  $t$ . For 2015–16, this is the price as determined in Table 16.17 escalated by  $(1 + \Delta CPI)$

$p_i^t$  is the price of service  $i$  in year  $t$ .

$$\Delta CPI_t = \left[ \frac{CPI_{Mar,t-2} + CPI_{Jun,t-2} + CPI_{Sep,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-3} + CPI_{Jun,t-3} + CPI_{Sep,t-2} + CPI_{Dec,t-2}} \right] - 1$$

$CPI$  means the all groups index number for the weighted average of eight capital cities as published by the ABS, or if the ABS does not or ceases to publish the index, then  $CPI$  will mean an index which the AER considers is the best estimate of the index.

$X_i^t$  is the X-factor for service  $i$  in year  $t$  in the regulatory control period, as set out in Table 16.2:

**Table 16.2 AER final decision on X factors for each year of the 2015–19 period**

	2015–16	2016–17	2017–18	2018–19
X factor	-0.76	-1.13	-1.22	-1.22

Source: AER analysis.

Note: The exceptions single phase, single element manually read interval meter; single phase two element meter and three phase meter. All these have an X factor of zero. To be clear, labour escalators themselves are positive for each year of the regulatory control period. However, the labour escalators in this table are operating as de facto X factors. Therefore, they are negative.

$\bar{p}_i^t$  is the cap on the price of service  $i$  in the first year of the subsequent regulatory control period. To be decided in the final decision.

## Form of control—quoted services

ActewAGL proposes to set prices on a quoted basis for those ancillary services where the service is not typical or standard, or the scope of the service is specific to particular customers' needs.<sup>3</sup>

We approve ActewAGL's proposed form of control for quoted services.<sup>4</sup> ActewAGL proposes to set prices for quoted services using the formula:

### Figure 16.2 Quoted services formula

$$\text{Price} = \text{Labour} + \text{Contractor Services} + \text{Materials} + \text{Other Costs} + \text{Risk Margin}$$

Where:

*Labour* (including on costs and overheads) consists of all labour costs directly incurred in the provision of the service which may include but is not limited to labour on costs, fleet on costs and overheads and other associated delivery costs including overheads. The labour cost for each service is dependent on the skill level and experience of the employee/s, time of day/week in which the service is undertaken, travel time, number of hours, number of site visits and crew size required to perform the service. Labour is escalated annually by  $(1-X_i)(1+\Delta\text{CPI}_i)$ .<sup>5</sup>

Table 16.3 sets out the escalation rates for each year that can apply to the labour rates.<sup>6</sup>

**Table 16.3 AER final decision on labour escalation factor to apply to maximum labour charge out rates for quoted services**

	2015–16	2016–17	2017–18	2018–19
X factor	-0.76	-1.13	-1.22	-1.22

Source: AER analysis.

Note: The exceptions single phase, single element manually read interval meter; single phase two element meter and three phase meter. All these have an X factor of zero. To be clear, labour escalators themselves are positive for each year of the regulatory control period. However, the labour escalators in this table are operating as de facto X factors. Therefore, they are negative.

<sup>3</sup> ActewAGL, *Regulatory Proposal 2015-19 Subsequent regulatory control period*, 2 June 2014 (resubmitted 10 July 2014), pp. 348-349.

<sup>4</sup> ActewAGL, *Revised Regulatory Proposal 2015-19 Regulatory control period*, January 2015, p. 641.

<sup>5</sup> The definition of X and  $\Delta\text{CPI}$  for Figure 16.2 are the same as for

Figure 16.1.

<sup>6</sup> Our opex rate of change attachment discusses the escalation factors.

*Contractor Services* (including overheads) reflects all costs associated with the use of external labour in the provision of the service, including overheads and any direct costs incurred as part of performing the service. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred as part of performing the service, for example permits for road closures or footpath access, are passed on to the customer. Contractor services are escalated annually by  $\Delta$ CPI.

*Materials* (including overheads) reflects the cost of materials directly incurred in the provision of the service, material storage and logistics on costs and overheads. Materials are escalated annually  $\Delta$ CPI.

*Other Costs* consists of costs that arise due to special requirements of the job or services provided at above the least cost technically acceptable standard. This term is consistent with ActewAGL’s approved Connection Policy, under which the customer pays the full costs of special requirements or above standard services.<sup>7</sup>

*Risk Margin* is the margin agreed with the customer to reflect the risks associated with the project. This will generally only apply to large scale projects, such as relocation or removal of major network assets at the request of a customer. The application of this margin represents a continuation of the approach that has applied under the ACT Capital Contributions Code, whereby a “reasonable profit margin” can be charged for relocations, removals and redevelopments.<sup>8</sup>

### 16.1.2 ActewAGL’s revised proposal

ActewAGL proposed that we should approve the labour rates for office support delivery and senior technical officer set out in its initial regulatory proposal.<sup>9</sup> Our consultant, Marsden Jacob Associates, calculated benchmark rates which we included in our draft decision. ActewAGL submitted that the draft decision does not explain the methodology adopted by Marsden Jacob.<sup>10</sup>

ActewAGL submitted that its proposed labour rates for ancillary network services are efficient. ActewAGL has updated these labour rates using its revised labour price escalators (Attachment 7). ActewAGL’s revised proposed labour rates are shown in Table 16.4.

**Table 16.4: Proposed labour rates (including on costs) for fee based and quoted services (\$ per hour, \$2014–15)**

Classification	2014–15	2015–16	2016–17	2017–18	2018–19
----------------	---------	---------	---------	---------	---------

<sup>7</sup> ActewAGL Distribution 2014, Connection Policy, version 2.0, June, p. 4. Services provided outside the scope of the Connection Policy and the chapter 5A Rules (for example services provided in accordance with the chapter 5 Rules) may also be subject to charges for above standard or special requirements.

<sup>8</sup> ICRC 2012, Electricity Network Capital Contributions Code, July 2012, clauses 3.7 and 3.8

<sup>9</sup> ActewAGL, *Revised regulatory proposal*, January 2015, p. 679.

<sup>10</sup> ActewAGL, *Revised regulatory proposal*, January 2015, p. 679.

Electrical worker	85.11	86.24	87.73	89.05	90.36
Electrical worker—labourer	69.52	70.44	71.65	72.74	73.8
Electrical apprentice	63.88	64.73	65.85	66.84	67.82
Office support service delivery	81.31	82.39	83.81	85.08	86.32
Project officer design section	100.22	101.56	103.31	104.87	106.41
Senior technical officer / Engineer design section	137.72	139.56	141.96	144.11	146.22

Source: ActewAGL, *Revised regulatory proposal*, January 2015, p.679.

ActewAGL also submitted that because of our draft decision, it was no longer possible for it to charge a fee for 'new underground service connection—greenfield and greenfield metering only' services. It submitted that imposing a fee for this type of service would be inconsistent with its connection policy.<sup>11</sup> Therefore, ActewAGL proposed to remove the following ancillary network service charges:

- New underground service connection—greenfield cable only
- New underground service connection—greenfield metering only

### 16.1.3 Assessment approach

This final decision continues to adopt the draft decision approach of focussing on the key inputs in determining prices for ancillary network services. We considered:

- ActewAGL's revised proposal.<sup>12</sup>
- Marsden Jacob's analysis of ancillary network services, including recommended maximum total labour rates for NSW and the ACT.

As with the draft decision, we consider labour is the key input in determining an efficient level of fees for ancillary network services. We focused on comparing ActewAGL's proposed total labour rates against maximum total labour rates for NSW that Marsden Jacob developed. In this final decision, 'total labour rates' comprise raw labour rates, on-costs, and overheads.

Our final decision maximum total labour rates apply the following labour components to arrive at a maximum total labour rate (for particular labour types):

- a maximum raw labour rate,
- a maximum on cost rate, and
- a maximum overhead rate

<sup>11</sup> ActewAGL, *Revised regulatory proposal*, January 2015, p. 672. We approved ActewAGL's connection policy in Attachment 18 to our draft decision.

<sup>12</sup> ActewAGL, *Revised regulatory proposal 2015–19*, 20 January 2015, pp. 637–679

to arrive at a maximum total labour rate (for that labour type).

As we explain in more detail in section 16.1.4, Marsden Jacob obtained ranges (that is, minimum rates and maximum rates) for each of these components. Marsden Jacob then applied the maximum from these ranges to derive the maximum total labour rate.<sup>13</sup> We consider that using Marsden Jacob's recommended maximum labour rates to determine appropriate fees for services will provide ActewAGL with a reasonable opportunity to recover at least the efficient costs it incurs in providing these services. It will promote the efficient provision of electricity services and allow a return commensurate with the regulatory and commercial risks involved for the provision of those services.<sup>14</sup>

Where ActewAGL's proposed total labour rates exceeded the maximum total labour rates we regarded as efficient, we applied our maximum total labour rates to determine ancillary network services charges. Equally, we adopted ActewAGL's proposed total labour rates where they sat below Marsden Jacob's maximum total labour rates.

As a further check of our analysis, we also compared components of ActewAGL's proposed labour costs with those of the Victorian distributors. We consider the latter's costs are closer to efficient levels.<sup>15</sup>

In coming to conclusions about the fees for ActewAGL's most frequently requested ancillary network services, we also assessed the times taken to perform the service.

#### **16.1.4 Reasons for final decision**

We do not approve ActewAGL's revised proposed fees for ancillary network services. The proposed fees exceed those based on maximum total labour rates for ActewAGL's labour types which we consider efficient for providing these services. As we set out in section 16.1.3, we compared ActewAGL's total labour rates against Marsden Jacob's maximum (rather than, for example, average) total labour rates. We note ancillary network services comprise a relatively small portion of ActewAGL's revenue. This is because a relatively small number of ActewAGL's customers request ancillary network services in any given regulatory year. Hence, we consider it prudent to use maximum total labour rates as an input to derive prices for ancillary network services. Maximum total labour rates act as 'ceilings' on the rates we consider ActewAGL should pay for the various labour types. Where ActewAGL reveals rates lower than the maximum total labour rates, we consider those lower rates should be the inputs for deriving ancillary network services prices. We consider this ensures the distribution business has a reasonable opportunity to recover at least its efficient costs, including a return commensurate with the regulatory and commercial risks in providing the services.

---

<sup>13</sup> Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, pp. 1–6.

<sup>14</sup> NEL, ss. 7A and 16

<sup>15</sup> Deloitte Access Economics, *NSW distribution network service providers labour analysis—Addendum to 2014 report*, April 2015.

Our assessment focussed on the inputs to the methods ActewAGL used to derive its fees for ancillary network services. In particular, labour is the major input to its proposed ancillary network services fees. We found proposed labour rates were inefficient. Hence, we adjusted ActewAGL's total labour rates where they exceeded the maximum total labour rates that Marsden Jacob developed and recommended (see section 16.1.3).

Each of the NSW and ACT distributors used different labour category names and descriptions. However, Marsden Jacob found that the types of labour used to deliver ancillary network services fell into one of five categories:

- administration
- technical services
- engineers
- field workers, and
- senior engineers.<sup>16</sup>

Table 16.5 shows the maximum total labour rates developed by Marsden Jacob and adopted by us. We consider these total maximum recommended labour rates should be used to assess ActewAGL's proposed charges for ancillary network services.

Marsden Jacob developed raw maximum recommended labour rates (that is, excluding on-costs and overheads) for each of these labour categories. It assessed raw labour rates, overheads and on-costs (see 16.1.4) separately and derived maximum rates for each component. Marsden Jacob then applied these maximum rates to produce the maximum total labour rates.

We used these maximum total labour rates to determine whether ActewAGL's proposed fees for ancillary network services reflect the underlying cost of an efficient labour rate. We consider this to be a prudent approach. It provides the distribution business with a reasonable opportunity to recover at least its efficient costs. We consider fees based on labour rates higher than the maximum total labour rates would be inefficient.

**Table 16.5: Final decision on maximum allowable labour rates (including on costs and overheads) (\$2014–15)**

Labour classification	Corresponding Marsden Jacob labour category	AER maximum allowable 2015–16 hourly total labour rates (\$2014–15)
Electrical worker	technical	142.81
Electrical worker—labourer	field worker	133.79

<sup>16</sup> Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 1.

Labour classification	Corresponding Marsden Jacob labour category	AER maximum allowable 2015–16 hourly total labour rates (\$2014–15)
Electrical apprentice	field worker	133.79
Office support service delivery	administration	89.06
Project officer design section	engineer	177.52
Senior technical officer / Engineer design section	senior engineer	210.96

Source: Marsden Jacob Associates, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, pp. 6 and 24.

Note: Ausgrid claimed confidentiality on its total labour rates.

Marsden Jacob also reviewed the times taken to perform ActewAGL's most frequently requested ancillary network services. Times taken to perform the seven most frequently requested ancillary network services were within benchmark times for these services. For the detailed review, refer to the Marsden Jacob report.<sup>17</sup>

- special meter read
- meter test
- supply of conveyancing information (desk inquiry)
- disconnection site visit
- disconnection at pole top / pillar box
- reconnections.

By adopting our final decision labour escalation rates (Attachment 7, appendix B has further details) in Table 16.1, we have made associated changes to the X factors that will apply to ActewAGL's services during the 2015–19 regulatory control period.

## Raw labour rates

In developing maximum raw labour rates (that is, excluding on-costs and overheads), Marsden Jacob examined Hays 2014 salary data. The Hays 2014 salary reports draw on information from 2,500 companies across Australia and New Zealand. Australian distributors in the Hays data (who gave permission to be named) were ActewAGL,

---

<sup>17</sup> Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014.

Jemena, and Citipower.<sup>18</sup> The Hays rates draw from a wide pool of labour which ActewAGL would likely have access to. We therefore consider these rates provide a good representation of the competitive market rate for appropriate categories of labour.

In its revised proposal, ActewAGL maintained that its proposed labour rates are efficient.<sup>19</sup>

AGL's submission queried whether the NSW distributors' proposed labour rates are efficient or even a current reflection of the NSW labour market. It submitted that the NSW distributors provided no justification as to why local market conditions require much higher labour rates than other states. AGL supported our comparison of labour rates and on-costs against other states as an appropriate means of evaluation and analysis.<sup>20</sup>

This echoes the Energy Users Association of Australia's (EUAA) submission not to allow the NSW distributors to effectively treat their negotiated labour rates in enterprise bargaining agreements as 'pass throughs'.<sup>21</sup>

We consider that AGL and the EUAA's submissions on the NSW distributors' proposals apply equally to ActewAGL.

We do not assume that a wage deal struck through an enterprise bargaining agreement is automatically efficient. If the service provider expected us to use the costs revealed through its enterprise bargaining agreement as the starting point for determining total labour expenditure, it would not have an effective incentive for cost control, or for the efficient provision of services and the efficient use of the distribution system.<sup>22</sup> Effectively, that would make such expenditures akin to cost of service regulation, rather than the NER's emphasis on incentive regulation.

As discussed below, Marsden Jacob developed its recommendations using labour types and their respective rates that are available in a competitive labour market.

Marsden Jacob reviewed salary information from all Australian cities. However, Marsden Jacob only used NSW salary data to develop its recommended maximum raw labour rates in respect of the NSW and ACT distributors.<sup>23</sup> Marsden Jacob compared labour rates it developed using the Hays NSW data against the Hays Victoria data. Marsden Jacob did this as a cross-check to test the reasonableness of its

---

<sup>18</sup> A list of contributors to the Hays 2014 salary data who gave permission to be named is available on Hays, *Contributors—Hays 2014 Salary*, accessed 12 February 2015, *Guide* [http://www.hays.com.au/salary-guide/HAYS\\_375078](http://www.hays.com.au/salary-guide/HAYS_375078)

<sup>19</sup> ActewAGL, *Revised regulatory proposal*, January 2015, p. 679.

<sup>20</sup> AGL, *Submission on NSW distributors draft decisions*, 15 February 2015, p. 4.

<sup>21</sup> Energy Users Association of Australia, *Submission to NSW Electricity Distribution Revenue Proposals (2014/15 to 2018/19)*, 8 August 2014, pp. 9–10; Energy Users Association of Australia, *Submission to NSW DNSP revised revenue proposal to AER draft determination (2014 to 2019)*, 13 February 2015, p. 44.

<sup>22</sup> NEL ss. 7, 7A and 16; AER, *Final decision: Powerlink transmission determination 2012–13 to 2016–17*, April 2012, p. 52.

<sup>23</sup> Marsden Jacob, *MJA analysis*.



recommended labour rates. Marsden Jacob found its recommended labour rates did not differ significantly from the Hays Victoria raw labour rate data.

In its report, Marsden Jacob also included raw labour rates across the five labour categories for Queensland and Auckland. Marsden Jacob included this data for illustration purposes—labour rates in each category did not vary significantly across these locations. The differences observed probably captured differences between locations including economic conditions, labour laws and population. For these reasons, we consider the NSW rates alone were acceptable to develop maximum recommended labour rates for ancillary network service charges for the NSW and ACT distributors.

Marsden Jacob used job titles from Hays’ energy specific salary guide to develop maximum recommended labour rates.<sup>24</sup> Marsden Jacob supplemented this with data from the Hays office support salary guide.<sup>25</sup> This ensured that the ‘administration’ category was sufficiently covered.

Marsden Jacob analysed 66 different job titles; Marsden Jacob used 36 of these in developing rates for the five labour categories.<sup>26</sup> These 36 labour job titles involved tasks which clearly fell into either the 'administration', 'technical specialist', 'engineer', 'field worker', or 'senior engineer' labour categories. Marsden Jacob excluded job titles that were not relevant to electricity distributors such as 'wind farm engineer'. Table 16.6 shows the 36 job titles Marsden Jacob used to develop recommended maximum labour rates for each of the five labour categories. We consider these 36 job titles provide Marsden Jacob with a sample of labour rates available in a competitive labour market.

**Table 16.6: Job titles Marsden Jacob used to develop benchmark labour rates**

Labour category		Job title
Admin	14 data points	Project secretary / Administrator
	(7 job titles)	Client liaison (residential)
		Data entry operator
		Records officer
		Administration assistant (12+ months experience)
		Project administration assistant (3+ years’ experience)
		Project coordinator
Technical specialist	22 data points	Technician

<sup>24</sup> Hays, *The 2014 Hays salary guide: salary & recruiting trends*, 2014.

<sup>25</sup> Hays, *The 2014 Hays salary guide: salary & recruiting trends*, 2014.

<sup>26</sup> Marsden Jacob Associates, *MJA analysis*.

Labour category		Job title
	(11 job titles)	Control room operator
		Control room manager
		E&I technician
		Protection technician
		Generator technician
		Operator / manager
		Site engineer
		Planner / scheduler
		OHS supervisor
		OHS manager
Engineer	14 data points	Design engineer
	(7 job titles)	Project engineer (EPCM)
		Power systems engineer
		Protection engineer
		Transmission line design engineer
		Asset engineer (3 to 7 years)
		Project engineer
Field worker	14 data points	Leading hand
	(7 job titles)	Electrician
		Mechanical fitter
		Line worker
		G&B linesworker
		Cable jointer
		Cable layer
Senior engineer	8 data points	Senior design engineer
	(4 job titles)	Principal design engineer
		Senior project engineer (EPCM)
		Commissioning Engineer

Source: Marsden Jacob Analysis

Marsden Jacob considered the range of data provided for each labour category across the various job titles. In doing this, it derived salary ranges for each labour category by:

- identifying the lowest salary from all job titles in the labour category

- identifying the highest salary from all job titles in the labour category.

We consider this range represents the full pool of labour (and raw labour rates) that ActewAGL would have access to in a competitive labour market. Marsden Jacob recommended using the maximum raw labour rate for each labour category to develop its maximum total labour rate.<sup>27</sup> We consider this to be a prudent approach. It provides the distribution business with a reasonable opportunity to recover at least its efficient costs, while promoting the efficient provision of services.

**Table 16.7: final decision maximum raw labour rates**

Marsden Jacob labour category	Corresponding ActewAGL labour categories	AER maximum raw labour rate (\$ per hour, \$2014–15)
Admin	Office support service delivery	39
Technical	Electrical worker	59
Engineer	Project officer design section	69
Field worker	Electrical worker - labourer, & electrical apprentice	47
Senior engineer	Senior technical officer / engineer design section	82

Source: Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, pp. 2–3.

## On-costs

Marsden Jacob recommended a maximum on cost rate of 52.23 per cent. Marsden Jacob developed a 'bottom up' estimate of on costs for the NSW and ACT distributors. Marsden Jacob did this for each of these businesses with reference to the following factors:

- the superannuation levels included in each distributor's enterprise bargaining agreement
- a conservative estimate of workers compensation premium
- standard payroll tax rates in NSW and the ACT
- annual leave loading of 17.5 per cent loading on four weeks annual leave, which equates to 1.35 per cent of total salary
- a conservative long service leave allowance based on three months leave for every ten years of service, equating to 2.5 per cent per year

<sup>27</sup> Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, pp. 2–3.

- an assumed rate of 18.18 per cent standard leave (including annual leave, sick leave, and public holidays) for all businesses.

Based on these factors, Marsden Jacob calculated a maximum on cost rate for the ACT and NSW businesses of 52.23 per cent.<sup>28</sup> It then used this maximum on cost rate to derive its maximum total labour rates. We consider this to be a prudent approach that is consistent with the revenue and pricing principles.

## Overheads

Marsden Jacob applied the maximum overhead rates in Table 16.8 to derive its total labour rates.<sup>29</sup> In recommending these maximum overhead rates, Marsden Jacob compared the overhead rates the NSW and ACT distributors proposed (in their original regulatory proposals). Marsden Jacob found that Ausgrid and Endeavour Energy's overhead rates were significantly higher than those of Essential Energy, and ActewAGL. They were also significantly higher than the Victorian distributors' overhead rates.<sup>30</sup> Marsden Jacob therefore recommended maximum overhead rates based on the maximum of only ActewAGL and Essential Energy's proposed overhead rates. Marsden Jacob's maximum overhead rates are also higher than the rates proposed by the Queensland distributors.<sup>31</sup> This adds further support to using Marsden Jacobs' maximum overhead rates to calculate maximum total labour rates. We therefore consider that Marsden Jacob's total labour rates, which use the overhead rates in Table 16.8 as inputs, are prudent and appropriately reflect the revenue and pricing principles.

**Table 16.8 Maximum overhead rates**

Labour type	Maximum overhead rates (per cent)
Administration	50
Technical specialist	59
Engineer	69
Field Worker	87
Senior Engineer	69
Average overheads	65

<sup>28</sup> Marsden Jacob, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 4.

<sup>29</sup> Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

<sup>30</sup> Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

<sup>31</sup> Ergon Energy, *Regulatory proposal 2015-20: 05.06.02—fixed fee services model*, 31 October 2014 (CONFIDENTIAL); Ergon Energy, *Regulatory proposal 2015-20: 05.06.03—quoted price services model*, 31 October 2014 (CONFIDENTIAL); Energex, *Regulatory proposal 2015-20: Alternative control services costing model*, 31 October 2014 (CONFIDENTIAL).

Source: Marsden Jacob Associates, *Final: Provision of advice in relation to Alternative Control Services – Public version: Advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

In its discussion of maximum overhead rates, Marsden Jacob noted:

- the nature of the differences in overhead rates may be due to differences in cost allocation methods
- capping the overhead rate may have unintended consequences for the broader cost allocation methodology
- we should test the method of addressing overhead allocation vis a vis the cost allocation method.<sup>32</sup>

We reviewed the objectives of our cost allocation guideline. The cost allocation method sets out the principles and policies for attributing costs to, or allocating costs between, the categories of distribution services a distributor provides. Hence, in approving a distributor's cost allocation method, we approve the methodology it uses to allocate costs. This does not equate to approving the costs. The approval of actual costs is subject to applicable requirements set out in the NER.<sup>33</sup> Proper application of the cost allocation method does not indicate whether the distributor's expenditure, including overheads, is at efficient levels or otherwise reflects the requirements of the NER, having regard to the revenue and pricing principles and the national electricity objective.<sup>34</sup> By extension, proper application of the cost allocation method does not indicate whether the resulting overhead rates represent efficient levels.

## **ActewAGL proposal—labour escalators, revenue recovery & X factors**

In its revised regulatory proposal, ActewAGL:

- made submissions about alternative revenue recovery options, depending on the outcome of final decision on standard control revenues.<sup>35</sup>
- proposed a set of X factors for fee based ancillary network services.<sup>36</sup>
- proposed 2015–16 charges for fee based ancillary network services.<sup>37</sup>

We consider that each ancillary network service should be priced by reference to its efficient costs—there should not be any cross-subsidies. We used maximum efficient labour rates to arrive at efficient 2015–16 prices for ActewAGL's fee based ancillary network services. We then used our final decision labour escalators to derive X factors

---

<sup>32</sup> Marsden Jacob Associates, *Provision of advice in relation to alternative control services—advice prepared for the Australian Energy Regulator*, 20 October 2014, p. 5.

<sup>33</sup> AER, *Electricity distribution network service providers—Cost allocation guidelines*, June 2008, p. 7-11.

<sup>34</sup> AER, *Electricity distribution network service providers—Cost allocation guidelines*, June 2008, p. 7-11.

<sup>35</sup> ActewAGL, *Revised regulatory proposal*, January 2015, p. 673.

<sup>36</sup> ActewAGL, *Revised regulatory proposal*, January 2015, p. 676-679.

<sup>37</sup> ActewAGL, *Revised regulatory proposal*, January 2015, pp. 673-676.

that will result in ActewAGL recovering an efficient level of costs over the regulatory control period.

## 16.2 Metering

Our final decision on ActewAGL's metering proposal is made in the context of ongoing policy reform. We based our assessment on the NER in place at the time of this final decision, but have had regard to the likelihood of policy reform in the future through rule changes that will apply during this regulatory period.

Currently, competition in metering is limited to large customers in the national electricity market while regulated distributors have the sole responsibility to provide small customers with metering services.<sup>38</sup>

The Australian Energy Market Commission (AEMC) is undertaking a rule change process to expand competition in metering and related services to help facilitate a market led roll out of advanced metering technology, following proposals from the COAG Energy Council. The increased availability of advanced meters will enable the introduction of more cost reflective network prices and allow consumers to make more informed decisions about how they want to use energy services.

The AEMC published its draft rule on 26 March 2015. It states that the AER should determine 'the arrangements for a DNSP to recover the residual costs of its regulated metering service in accordance with the existing regulatory framework'.<sup>39</sup> Other key features of the draft rule change include:

- the transfer of the role and responsibilities of the existing 'Responsible Person' to a new type of Registered Participant called a Metering Coordinator
- allowing any person to become a Metering Coordinator, subject to meeting the registration requirements
- permitting a large customer to appoint its own Metering Coordinator
- requiring a retailer to appoint the Metering Coordinator, except where a large customer has appointed its own Metering Coordinator.<sup>40</sup>

Our final decision takes the AEMC's draft rule into account and establishes a regulatory framework for the 2015-19 regulatory period which will be robust enough to handle the transition to competition once the rule change takes effect from 1 July 2017.<sup>41</sup> This involves having transparent standalone prices for all new or upgraded meter connections and annual charges.

---

<sup>38</sup> NER clause 7.2.3(a). Small customers refers to any customer with less than 160MWh annual consumption (effectively all residential and small business customers fall into this category).

<sup>39</sup> AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. 225.

<sup>40</sup> AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. iii.

<sup>41</sup> AEMC, *Draft rule determination: Expanding competition in metering and related services*, 26 March 2015, p. 79.

The key issue in the lead up to competition is how to recover the residual metering capital costs that arises when metering customers begin to switch to competitive metering providers. Rather than an upfront exit fee which would create a regulatory barrier to competitive entry, our final decision is that switching customers continue to pay the capital cost component of the regulated annual metering service charge.

## 16.2.1 Final decision

### Structure of metering charges

We have classified type 5 and 6 metering services as alternative control services. The control mechanism for alternative control metering services will be caps on the prices of individual services.

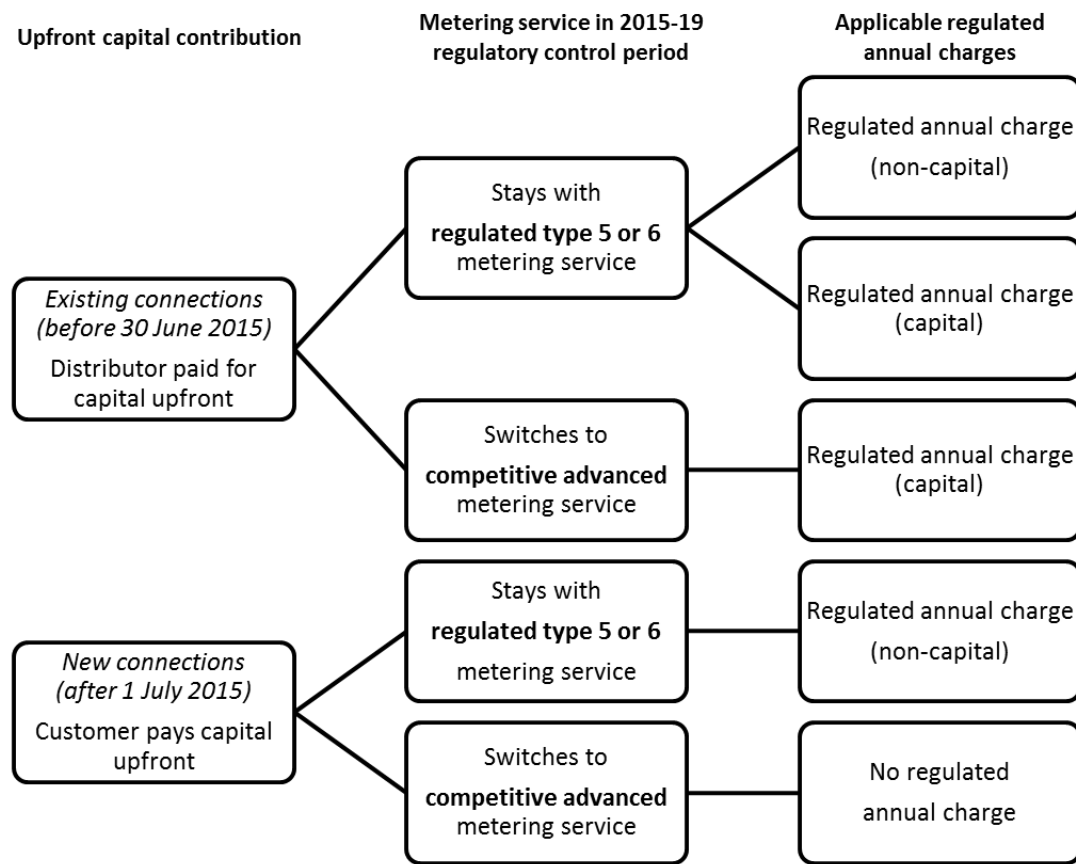
Our final decision approves two types of metering service charges:

- Upfront capital charge (for all new and upgraded meters installed from 1 July 2015)
- Annual charge comprising of two components:
  - capital —metering asset base (MAB) recovery
  - non-capital —operating expenditure (opex) and tax.

We have not approved a meter transfer fee relating to administrative costs associated with metering customers who switch to a competitive metering provider.

Figure 16.3 depicts how the two regulated annual charge components relate to different metering customers.

**Figure 16.3 – Final decision – Applicable regulated metering charges**



Source: AER analysis.

This diagram shows regulated annual charges only. In addition, customers who switch may incur charges for their competitive advanced metering service. Any such charges are not subject to AER oversight and are not shown in the diagram above.

### Existing connections (before 30 June 2015)

For regulated meters installed before 30 June 2015, metering capital costs were amortised. That is, distributors paid upfront for the capital costs which were then added to the asset base and recovered gradually through annual charges.

If a customer with an existing regulated metering connection on their premises receives a regulated type 5 or 6 metering service, they pay the following charges:

- Capital (MAB recovery<sup>42</sup>) component of regulated annual metering charge
- Non-capital (opex and tax) component of the regulated annual metering charge.

<sup>42</sup> The MAB is largely the undepreciated value of all existing meters. It will increase slightly in the 2015–19 regulatory control period to include forecast replacement capex. A meter has to be replaced if it suddenly fails or may have to be proactively replaced because the distributor must comply with AEMO's metrology procedures.



If a customer with an existing regulated metering connection on their premises chooses to switch to a competitive advanced metering service (and no longer receives a regulated type 5 or 6 metering service) they stop paying the non-capital component of the regulated annual metering charge. They will pay the following charges:

- Capital component of the regulated annual metering charge
- This charge recovers the MAB from all customers with existing connections (from before 30 June 2015) on their premises, whether or not they subsequently switch from their existing regulated meter to an advanced meter. As a result, the diminishing number of customers who remain with their existing regulated meters are not required to pay the entire capital cost of the MAB. This has the benefit of minimising cross subsidies between customers switching to competitive meters and those remaining on regulated meters. It also means the contribution towards the recovery of the MAB is relatively small because it is paid through ongoing annual charges rather than an upfront exit fee
- Any charges payable to their competitive metering provider for advanced metering services. Any such charges are not subject to AER oversight and are not shown in Figure 16.3.

This structure applies even if a customer pays upfront for a meter upgrade to their existing regulated meter after 1 July 2015 (for example, wants to upgrade from a type 6 to a type 5 meter) and then switches to a competitive advanced metering provider. This is because the upfront capital charge recovers the costs of the meter upgrade, but not of the existing meter installed before 30 June 2015.

### **New connections (after 1 July 2015)**

For regulated new meter connections installed after 1 July 2015, the capital costs will be paid upfront by the customer. As such, no capital expenditure (capex) related to new meter connections installed after this date will be added to the MAB.

If a customer has a new regulated metering connection that was installed on their premises after 1 July 2015 and receives a regulated type 5 or 6 metering service, they pay the following charges:

- Non-capital component of the regulated annual metering charge
- As they have already paid for their capital component upfront, the only costs relating to their regulated metering service left to be recovered through annual charges are the non-capital costs.

If a customer has a new regulated metering connection on their premises and wants to switch to a competitive advanced metering service (and no longer receives a regulated type 5 or 6 metering service), they stop paying all regulated annual metering charges. They will pay the following charges:

- Any charges payable to their competitive metering provider for advanced metering services. Any such charges are not subject to AER oversight and are not shown in Figure 16.3.

## Annual metering service charges

We generally accept ActewAGL's building block approach as the basis for establishing annual metering charges. With respect to each building block, our final decision is:

- Opening MAB

We maintain our draft decision<sup>43</sup> to accept ActewAGL's proposed opening MAB as at 1 July 2014 of \$50.04 million (\$ nominal).<sup>44</sup>

- Depreciation

We do not accept ActewAGL's revised proposal to apply accelerated depreciation to the assets in its MAB over a nine year period.<sup>45</sup> Instead we uphold our draft decision for a standard asset life of 15 years and that forecast, as opposed to actual, depreciation will apply to ActewAGL's MAB.<sup>46</sup>

- Forecast capex

We accept ActewAGL's revised capex building block of \$13.0 million (\$2014–15). It incorporates a change in capitalisation policy for new or upgraded connections, which our draft decision included.<sup>47</sup> The revised amount (\$13.0 million) is a reduction from ActewAGL initially proposed \$33.2 million (\$2014–15).<sup>48</sup>

- Forecast opex

In assessing the metering opex building block, we used a base-step-trend approach to developing an alternative forecast. Our cost assessment led us to approve \$11.1 million in opex<sup>49</sup> for annual metering services in place of the proposed \$16.1 million (\$2014-15).

Based on our cost assessment of the individual building blocks we do not accept ActewAGL's proposed price caps for annual metering charges. Our substitute price caps are set out in Appendix A.

## Upfront capital charges

We accept ActewAGL's proposed price caps for new or upgraded connections, which from 1 July 2015 will be recovered as an upfront charge to customers. The charges we have accepted are set out in Appendix A.

---

<sup>43</sup> AER, *Draft decision on ActewAGL's regulatory proposal: 2014-15 and 2015-19*, November 2014, p. 16–34.

<sup>44</sup> ActewAGL, *Revised regulatory proposal 2015-19, H10 - PTRM Modelling*, January 2015.

<sup>45</sup> ActewAGL, *Revised regulatory proposal 2015-19*, January 2015, p. 662.

<sup>46</sup> AER, *Draft decision on ActewAGL's regulatory proposal: 2014-15 and 2015-19*, November 2014, p. 16–34. Forecast depreciation is consistent with our approach applied to standard control services in this final determination.

<sup>47</sup> AER, *Draft decision on ActewAGL's regulatory proposal: 2014-15 and 2015-19*, November 2014, p. 16–29.

<sup>48</sup> ActewAGL, *Initial regulatory proposal, Attachment B8, Metering PTRM*, May 2014. Converted to \$2014–15.

<sup>49</sup> Exclusive of debt raising costs.

## Meter exit fee

We do not approve a meter exit fee to recover the residual value of meters associated with customers switching to competitive metering providers. Nor do we accept an exit fee to recover administration costs.

## Control mechanism

Our final decision is to apply price caps for individual type 5 and 6 metering services as the form of control. This means a schedule of prices is set for the first year. For the following year's the previous year's prices are adjusted by CPI and an X factor. The control mechanism formula is set out below:

$$\bar{p}_i^t \geq p_i^t \quad i=1,\dots,n \text{ and } t=1,2,3,4$$

$$\bar{p}_i^t = \bar{p}_i^{t-1}(1 + \Delta CPI_t)(1 - X_i^t)$$

Where:

$\bar{p}_i^t$  is the cap on the price of service  $i$  in year  $t$ . However, for 2015–16 this is the price as determined in Appendix A.

$p_i^t$  is the price of service  $i$  in year  $t$ .

$$\Delta CPI_t = \left[ \frac{CPI_{Mar,t-2} + CPI_{Jun,t-2} + CPI_{Sep,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-3} + CPI_{Jun,t-3} + CPI_{Sep,t-2} + CPI_{Dec,t-2}} \right] - 1$$

$CPI$  means the all groups index number for the weighted average of eight capital cities as published by the ABS, or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index.

$X_i^t$  is:

- for the annual metering charges the factors set out in Table 16.9
- for the upfront capital charges the factors set out in Table 16.10.

**Table 16.9 – Approved X-Factors for annual metering charges (per cent)**

	2016–17	2017–18	2018–19
X factor	0.0	0.0	0.0

Source: AER analysis.

**Table 16.10 – Approved X-Factors for the upfront capital charges (per cent)**

	2015–16	2016–17	2017–18	2018–19
X factor	-0.45	-0.68	-0.73	-0.73

Source: AER analysis.

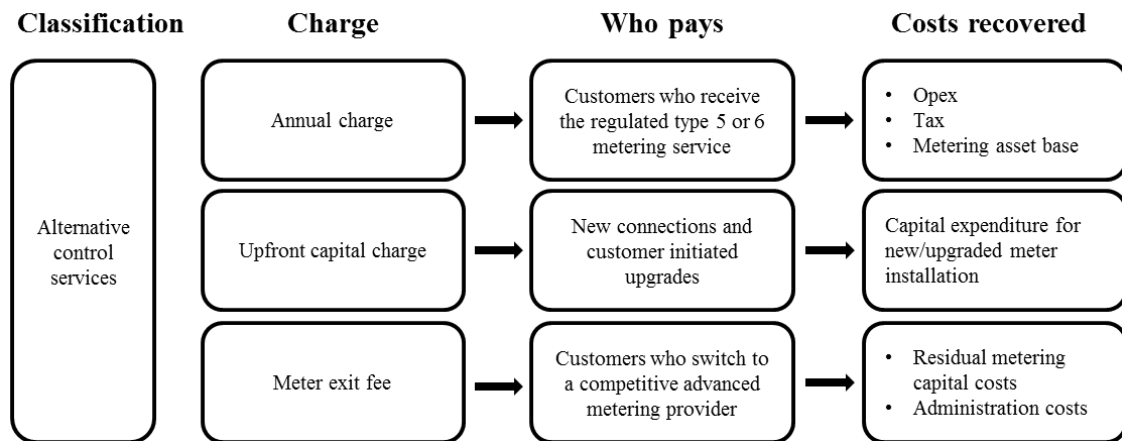
We will check for compliance with the control mechanism during the annual pricing process. To be compliant, ActewAGL must annually adjust individual price caps in accordance with the control mechanism formula shown above. Further, ActewAGL must show that individual prices are less than or equal to the approved price cap for that individual service through providing a copy of its published price list for that year.

### 16.2.2 ActewAGL's revised proposal

In January 2014, ActewAGL submitted its revised metering proposal for the 2015–19 regulatory control period. It accepted the service classification and control mechanism outlined in our draft decision.<sup>50</sup> That is, ActewAGL accepted our classification of metering services as alternative control services and proposed price caps on individual metering services.<sup>51</sup>

### Structure of metering charges

**Figure 16.4 – Revised proposal – structure of metering charges**



Source: AER analysis.

<sup>50</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 645.

<sup>51</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 645.

ActewAGL accepts our draft decision to charge for new or upgraded connections upfront and to establish separate annual charges for new existing customers.<sup>52</sup>

However, it did not accept our draft decision to recover residual metering capital costs through standard control services, and maintains its initial position to charge a meter exit fee to recover residual metering capital costs and administration costs.<sup>53</sup>

ActewAGL's revised proposal position on exit fees is discussed further in 16.2.2.

## Annual metering services

For each tariff class, ActewAGL proposed a price cap for annual metering services. The costs that constitute the annual metering service charges were built up by applying a 'building block' approach. This involved forecasting the revenue requirement for each of ActewAGL's metering cost categories and then translating this into price caps. Table 16.11 sets out ActewAGL's proposed metering building block requirement. Table 16.12 shows the proposed annual charges for metering services that recover the total proposed revenue.

**Table 16.11 – ActewAGL's proposed metering building block revenue requirement (\$ million, nominal)**

	2014–15	2015–16	2016–17	2017–18	2018–19
Return on capital	4.4	4.6	4.3	3.9	3.5
Return of capital	4.5	5.4	5.9	6.5	7.2
Opex	3.0	3.2	3.3	3.5	4.3
Benchmark tax liability	1.0	1.0	1.1	1.1	1.1
Total	12.8	14.2	14.5	15.0	16.1

Source: ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 663.

**Table 16.12 – ActewAGL's proposed prices for annual metering services (\$ annual, 2014–15)**

Tariff class	Price per NMI	Price per NMI
	Existing customers	New customers
<b>Quarterly basic</b>		
Accumulation and time-of-use	80.34	24.35
<b>Monthly basic</b>		
Accumulation and time-of-use	116.80	60.81

<sup>52</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 650.

<sup>53</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 650.

Tariff class	Price per NMI	Price per NMI
	Existing customers	New customers
<b>Time-of-use metering rate</b>		
Time-of-use meters read monthly	116.80	60.81
<b>Monthly manually read interval metering rate</b>		
Interval meters recording at either 15- or 30-minute intervals, read manually and processed monthly	719.05	660.65
<b>Quarterly manually read interval metering rate</b>		
Interval meters recording at either 15- or 30-minute intervals, read manually and processed quarterly	227.76	171.77

Source: ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 665–6.

## Meter exit fee

ActewAGL considered that our draft decision to classify the recovery of residual type 5 or type 6 meter capital costs as a discrete, additional standard control service to smear recovery through network tariffs from the general customer base is legally impermissible.<sup>54</sup> It gave the following reasons:

- The AER can only classify a service, not a category of cost
- The NER prohibits the inclusion of assets into the RAB for standard control services that are not used to provide standard control services
- The NER does not permit additions to the RAB for standard control services during the regulatory control period.

In addition to its legal concerns ActewAGL had other objections, including that our draft decision does not reconcile with policy views expressed by SCER (now the COAG Energy Council) and any departure from those policy views should be a policy decision made by the AEMC.<sup>55</sup>

In its revised proposal, ActewAGL maintained its position that a meter exit fee should apply when customers switch, to recover residual metering capital costs and administration costs involved in the administration of customer transfers from its database to those of competing providers.<sup>56</sup>

## Upfront capital charge

ActewAGL's treatment of new or upgraded connections in its revised regulatory proposal is different to its initial proposal. Initially ActewAGL proposed to include the capital cost recovery of new or upgraded connections in its annual metering charge. In

<sup>54</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p.651.

<sup>55</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p.653.

<sup>56</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p.638–9.

its revised proposal, however, ActewAGL applied our draft decision such that it now seeks to establish upfront capital charges for new or upgraded connections from 1 July 2015.<sup>57</sup>

The proposal for upfront charges for new or upgraded connections is consistent with our draft decision. We maintain our position in the draft decision that such charges should improve cost visibility and facilitate comparisons by consumers in the lead up to competition in metering. This is by shifting how the capital costs for new and upgraded meters are recovered, from the annual metering services charge where costs are smeared across all customers, to an upfront and direct payment which new entrants to the market can compete against on price.<sup>58</sup>

Table 16.13 sets out ActewAGL's proposed upfront charges for new or upgraded meters. The proposed charges for installing a meter are also included.

**Table 16.13 – ActewAGL averaged proposed new or upgraded meter prices in the 2015–19 regulatory control period (\$2014–15)**

Meter description/activity	Upfront charge
Install meter (excludes cost of meter)	359.54
Install subsequent meter – same location and visit (excludes meter)	179.77
Install / replace meter – micro renewable energy installation (excludes meter)	359.54
Single phase, single element manually read interval meter	129.22
Single phase, two element meter	234.85
Three phase meter	356.16

Source: ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 660.

## Control mechanism

ActewAGL noted that our draft decision did not make a constituent decision on how compliance with the control mechanism for metering services is to be demonstrated.<sup>59</sup>

<sup>57</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 650.

<sup>58</sup> AER, *Draft decision on ActewAGL's regulatory proposal: 2014-15 and 2015–19*, November 2014, p. 16–30.

<sup>59</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 650.

## 16.2.3 Assessment approach

ActewAGL proposed price caps on three categories of metering services.<sup>60</sup> These are annual metering services, upfront capital charges for new or upgraded connections, and a meter exit fee.

### Structure of metering charges

#### AEMC Draft Rule Change

The AEMC's draft rule change does not specify a method, but considered that the AER should determine how distributors recover residual capital costs of its regulated metering service in accordance with the existing regulatory framework.<sup>61</sup>

#### National Electricity Law

We had regard to the national electricity objective and the revenue and pricing principles which include providing a distribution business with a reasonable opportunity to recover at least its efficient costs.<sup>62</sup>

#### National Electricity Rules

We had regard to the distribution pricing principles set out in clause 6.18.5 of the NER, which include the requirement that revenue recovered should be between the standalone and avoidable cost of serving that customer group.

In determining the appropriate structure of metering charges we have made decisions on the classification of the service and the control mechanism. The classification and control mechanism to recover metering capital costs that risk becoming stranded if a customer switches was not explicitly considered in our Stage 1 Framework and Approach.<sup>63</sup> Our final decision classification and control mechanism has been made with regard to the factors set out in clauses 6.2.2(c) and 6.2.5(c) of the NER. We had particular regard to:

- how the classification/control mechanism may influence the potential for competition in unregulated metering
- a method that provides administrative simplicity for customers, ActewAGL and the AER where possible

---

<sup>60</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 650.

<sup>61</sup> AEMC, Draft Rule Determination (Expanding competition in metering and related services), 26 March 2015, p 225

<sup>62</sup> NEL, Revenue and Pricing Principles, 7A (2).

<sup>63</sup> NER, cl. 6.12.3 (b) (cl). We may depart from the classification and control mechanism decisions made in our framework and approach paper if we consider there have been unforeseen circumstances. The unforeseen circumstance in this case was that there previously was no stranding risk because customers had no choice to exit regulated metering. As such, we did not consider residual metering costs in our framework and approach paper (March 2013) which was released prior to SCER metering rule change request (October 2013).



- the extent to which costs can be directly attributable to individual customers in order to minimise cross subsidies.

We also have a preference for a nationally consistent approach. Our approach to the classification of services is discussed in Attachment 13.

## Annual metering service charges

We assessed ActewAGL's proposed opening MAB, depreciation, capex and opex components associated with the annual metering service.

### Opening metering asset base

In assessing ActewAGL's proposed opening MAB, we reviewed how ActewAGL had separated its proposed opening MAB as at 1 July 2014, from the regulatory asset base (RAB) for standard control services.

### Depreciation

With respect to depreciation, we considered the remaining asset lives ActewAGL proposed and had regard to the opening of competition to metering services.

### Forecast capex

Our approach to assessing the revised proposal on forecast capex was consistent with our draft decision. We reviewed the following:

- the proposed 'material' and 'non-material' unit costs<sup>64</sup>
- the forecast volume of reactive and proactive replacements.

Further, from 1 July 2015, ActewAGL's customers will incur an upfront payment recovering the capital cost of meters installed at 'new or upgraded connections'. The commencement date for the upfront payment (1 July 2015) is the earliest available under the NER. This provides that the existing cost allocation approach leading up to placeholder year must be retained in 2014–15.<sup>65</sup> In the case of new or upgraded connections, the capital cost of the meters must be recovered under the general network charge for standard control services. However from 1 July 2015, ActewAGL proposed to change its capital contribution policy so that such costs are recovered directly from customers.<sup>66</sup>

New or upgraded connections in 2014-15 formed part of our assessment of ActewAGL's proposed capex building block for annual metering services. However, the 'true-up' of any differences between the capital costs ActewAGL recovered in the

---

<sup>64</sup> Material costs relate to the hardware used to provide metering services. Non-material costs relate to the labour activities which ActewAGL must perform to install a new or replaced meter.

<sup>65</sup> NER, cl. 6.15.2(7).

<sup>66</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 659.

2014–15 placeholder year with our assessment of what we consider to be prudent and efficient will actually be recovered under the general network service charge.

### **Forecast opex**

We applied the same approach to assessing ActewAGL's proposed opex, as in our draft decision.

Opex refers to the operating, maintenance and other non–capital costs, including labour, incurred in the provision of metering services.

After determining ActewAGL's efficient base opex, and accounting for any (positive or negative) step changes, we trended forward that amount over the 2015–19 regulatory control period. This is known as the 'base, step and trend' approach.

### **Base**

As opex is largely recurrent in nature, we considered ActewAGL's historical costs to be a useful starting point to establish a base to forecast future costs. We also used benchmarking to assess the relative efficiency of the base year compared with comparable network businesses in the national electricity market.

Our base assessment uses historical data over a five year period, rather than selecting a single base year. Given that we do not apply an efficiency benefit sharing scheme (EBSS) to alternative control services, we consider an average of multiple years to be a better measure of a business' efficient base; it avoids any incentive to 'load' a single base year with expenditure going forward.

We used 'opex for metering' data collected in our economic benchmarking regulatory information notices (RIN). This audited data is suitable for comparison because the data provided by the distributors was prepared according to a consistent set of instructions and definitions.<sup>67</sup>

Our metering assessment relates to annual charges for default metering services common to all regulated type 5 and 6 metering customers. There are also ancillary metering services paid for by customers specifically requesting a service like an off-cycle meter read or a meter accuracy test. However, the economic benchmarking metering opex data does not distinguish between ancillary and default metering services. We did not make this adjustment for the draft decision, but have adjusted base metering opex data to exclude ancillary metering service costs for the final decision.

With this adjusted base data, we then performed our benchmarking analysis. We used a partial performance indicator for our benchmarking analysis. This compared historic

---

<sup>67</sup> AER, Economic benchmarking RIN for distribution network service providers - Instructions and Definitions - Sample, November 2013.

annual metering opex per customer across non-Victorian distributors<sup>68</sup> in the national electricity market.

Our benchmarking analysis for metering is a simpler version than what we used to assess standard control opex. This reflects the generally lighter handed regulatory approach to alternative control services compared with standard control services. For example, our econometric modelling results we used to assess standard control opex were based on data for network services and therefore do not strictly apply to metering services.

As with our draft decision, we adjusted the benchmarking results for customer density. This is a network characteristic exogenously influences opex requirements.

### **Step changes**

When assessing a distributor's proposed step changes, we considered if they are needed for the total opex forecast to reasonably reflect the opex criteria.<sup>69</sup> Our assessment approach is consistent with the approach specified in our *Expenditure forecast assessment guideline*.<sup>70</sup>

We generally consider an efficient base level of opex is sufficient for a prudent and efficient distributor to meet all existing regulatory obligations. This is the same regardless of whether we forecast an efficient base level of opex based on the service provider's own costs or the efficient costs of comparable benchmark providers. We only include a step change in our forecast if we are satisfied a prudent and efficient service provider would need an increase in its opex.

Step changes should generally relate to a new obligation or some change in the service provider's operating environment beyond its control. It is not enough to simply demonstrate an efficient cost will be incurred for an activity that was not previously undertaken.

### **Trend**

We then trended forward base opex (plus any step changes) by considering forecast changes in output, price and productivity.

For both capex and opex, we had regard to the capex and opex objectives and criteria in chapter 6 of the NER.<sup>71</sup> Though these considerations relate to standard, as opposed to alternative, control services, they are helpful and relevant in providing a general framework for assessing a building block expenditure forecast. Among other things,

---

<sup>68</sup> Victorian distributors rolled out advanced metering technology in the last regulatory period. These costs are not comparable to other distributors which have type 5 and 6 meters.

<sup>69</sup> NER, cl. 6.6.5(c).

<sup>70</sup> AER, *Expenditure assessment forecast guideline*, November 2013, p.11, 24.

<sup>71</sup> NER, cl. 6.5.6 and 6.5.7.

when considering a distribution business's forecast, the capex and opex objectives and criteria state we should consider:

- the efficient costs required
- the costs a prudent operator would incur
- whether the proposed cost inputs are realistic.<sup>72</sup>

## Upfront capital charge

To assess the reasonableness of the proposed charges from 1 July 2015, we analysed ActewAGL's unit costs. We did not consider the forecast volumes of new or upgraded connections for the 2015–19 regulatory control period; they have no bearing on the quantum of the upfront charge.

## Meter exit fee

We considered the appropriate method to recover the residual metering asset value as part of our structure of metering charges assessment.

With regard to the administration component of the proposed exit fee, we must balance revenue recovery for the efficient costs of the distributor's service provision with identifying and removing barriers to entry and competition, consistent with the proposed metering rule change submitted by the COAG Energy Council and currently being deliberated by the Australian Energy Market Commission.

We undertook a cost assessment underlying the proposed meter transfer fees to determine the efficiency of those costs. To assess costs we considered the activities either required, or reasonably expected to be required, for a meter transfer, by both a distributor and a competing metering provider. We had regard to the costs estimated to be incurred from such activities in New South Wales, the Australian Capital Territory, Queensland and South Australia. Victorian distributors are under a State Government mandated smart meter roll out, and so meter transfer is not a comparable activity that can be presently undertaken and therefore benchmarked.

We consulted with first and second tier retailers and the Australian Energy Market Operator to ascertain those activities necessary for the efficient transfer of meter customers among service providers. The New South Wales and Australian Capital Territory distributors' revised revenue proposals, and the initial proposals from Queensland and South Australia's distributors, outlined the activities they would undertake to transfer customers.

---

<sup>72</sup> NER, cl. 6.5.6(c) and 6.5.7(c).

## Interrelationships

Our final decision should provide ActewAGL with an opportunity to recover at least its efficient costs.<sup>73</sup> This includes, where relevant, providing enough expenditure for the business to repay its debt financing costs and earn a reasonable return on its investments.

Our final decision on ActewAGL's alternative control metering proposal, therefore, interrelates with our assessment of its proposed rate of return. Refer to attachment 3 of this final decision for the rate of return we accept for direct control services,<sup>74</sup> along with our reasons. Unlike standard control services, we will not be annually adjusting for the return on debt for alternative control services. The only annual changes for price caps for alternative control services will be consistent with our price control mechanism formula set out in 0.

### 16.2.4 Reasons for final decision

Our reasons for not accepting ActewAGL's proposed charges for annual metering services, new or upgraded connections, and the meter exit fee are discussed in this section.

### Structure of metering charges

Our final decision approves two types of charges:

- Upfront capital charge (for all new and upgraded meters installed from 1 July 2015)
- Annual charge comprising two components:
  - capital—metering asset base (MAB) recovery
  - non-capital—opex and tax.

We approve an upfront capital charge for two reasons. Firstly, it directly attributes the capital costs to the customer who initiates the meter installation. Secondly, it is appropriate in the context of expanding competition in metering. It is difficult to forecast the number of new regulated type 5 and 6 meters that will be installed in the upcoming 2015–19 regulatory control period. By charging upfront, we avoid having to forecast capex for new and upgraded metering installations that may not eventuate.

To better meet the distribution pricing principles, it is important for annual charges to be set on a cost-reflective basis. It is particularly significant in the context of expanding competition in metering. Previously, metering was a standard control service and the related metering costs were bundled into general network tariffs. There was no transparency around the costs of providing regulated metering services. By setting cost-reflective regulated metering charges, customers will be able to compare the

---

<sup>73</sup> NEL, Revenue and Pricing Principles, 7A (2).

<sup>74</sup> Direct control services are defined in Chapter 10 of the NER to include standard and alternative control services.

costs of their current regulated service with offers from alternative metering providers when competition begins.

We consider that a cost-reflective annual charge for new metering connections installed after 1 July 2015 should only consist of non-capital costs (opex and tax). This is because the capital cost of meters installed after 1 July 2015 would have been fully customer funded. In contrast, pre 30 June 2015 customers on a regulated type 5 or 6 metering service who have not paid for the meter upfront should contribute to the MAB recovery through their annual charge. That is, they pay a cost-reflective annual charge that includes both capital and non-capital components. This is the way such customers pay for their regulated metering services now.

However, if a customer chooses to switch to a competitive metering provider, the capital component of the annual charge would become stranded for the distributor. That is unless there is a mechanism for recovering that cost. It is important to recognise that customers pay the capital costs of a meter on an annual basis, they represent an amortised cost (that is, have been paid for upfront by the distributor and then recovered gradually over time from customers). Past capex is a fixed cost because it does not vary with how many customers switch; the capital costs have already been incurred by the distributor to provide a regulated metering service. This is in contrast to metering opex, such as meter reading costs, which are largely variable. This means the distributor can avoid those costs if a customer switches.<sup>75</sup>

QCROSS considers:

*"it would be inappropriate to recover residual costs associated with a service that customers are not getting any benefit from.... distributors should not be allowed to recover such costs from consumers - either through a charge which is allocated across all customers nor via individual exit fees."<sup>76</sup>*

But this effectively means that the distributor would be unable to recover the undepreciated residual value of those meters. The revenue and pricing principles provide that distributors should have a reasonable opportunity to recover at least their efficient costs. We therefore consider it appropriate that distributors recover their fixed capital costs that were incurred in providing regulated metering services.

Accordingly, we considered the most appropriate way to recover metering capital costs incurred in providing regulated metering services that risk becoming stranded if a customer switches.

ActewAGL considered that it was the AEMC's role to make a policy decision to depart from the policy views expressed in SCER's rule change request.<sup>77</sup> In its draft rule change, the AEMC confirmed that "the arrangements for a DNSP to recover the

---

<sup>75</sup> Although the capital costs of the meter remain to be recovered by the distributor, there is no longer any need to read the meter, thus providing an opex saving.

<sup>76</sup> QCROSS Submission to AER Consultation Paper (Recovery of Residual Metering Costs), 31 March 2015, p 2

<sup>77</sup> ActewAGL, Revised Regulatory Proposal, p. 653.

residual costs of its regulated metering service should be determined by the AER in accordance with the existing regulatory framework."<sup>78</sup> The AEMC note that relevant aspects of the regulatory framework include the NEO, the revenue and pricing principles as set out in section 7A of the NEL, distribution pricing principles as set out in rule 6.18 of the NER and the provisions regarding the classification of distribution services and applicable control mechanism as set out in rule 6.2 of the NER.<sup>79</sup> These are the criteria we have considered in making our final decision.

ActewAGL proposed to charge an upfront exit fee when a customer wished to switch to a competitive metering provider. This would ensure it recovered its metering capital costs for existing meters that would otherwise become stranded.

However various stakeholders raised concerns that a large upfront exit fee would be a barrier to competitive entry and to the take up of advanced metering.<sup>80</sup> In particular, it potentially creates a first mover disadvantage because a market-led smart meter rollout is predicated on the customer not having to pay any charges upfront.<sup>81</sup> Therefore, the first mover competitive metering provider may have to pay for both an exit fee as well as the new smart meter—and bear the risk of those sunk costs if the customer decided to move to another competitive metering provider. We consider that exit fees create a regulatory barrier to a market-led roll out of advanced metering.

There are several methods of ensuring distributors can recover capital costs incurred in providing regulated metering services. After extensive consultation with stakeholders<sup>82</sup>, we decided on a method that we considered best balances the objectives of distributors and customers and meets regulatory objectives to promote competition in metering services.

Based on economic principles, the efficient investment signal to switch to unregulated metering would be to set individual exit fees based on the remaining economic value of the individual meter associated with the customer making the decision to switch. The remaining economic value would vary with the capability of the meter (the meter type) and remaining life (the age) of the meter. This would ensure that an existing meter

---

<sup>78</sup> AEMC, Draft Rule Determination (Expanding competition in metering and related services), 26 March 2015, p. 225.

<sup>79</sup> AEMC, Draft Rule Determination (Expanding competition in metering and related services), 26 March 2015, p. 225.

<sup>80</sup> Consumer Challenge Panel, Updated submission on NSW DNSPs regulatory proposals 2014-19, 15 August 2014, pp. 36-7.

Vector Limited, Submission on DNSPs regulatory proposals, 8 August 2014 p. 4.

ERAA, Submission on Issues paper NSW electricity distribution regulatory proposals, 8 August 2014, p. 2.

Origin Energy, Submission on NSW electricity distributors regulatory proposal (attachment 1), 8 August 2014, p. 33.

AGL, Submission on NSW electricity distribution networks regulatory proposals, 8 August 2014, p. 21.

PIAC, Submission on NSW electricity distribution network price determination, 8 August 2014, p. 105.

<sup>81</sup> Vector Limited, Submission on DNSPs regulatory proposals, 8 August 2014 p. 4.

<sup>82</sup> In addition to our normal consultative process which allows stakeholders to provide submissions on the distributor's proposal and our draft decision, we also held a metering workshop on 11 September 2014 and released a consultation paper (on the alternative approach to the recovery of the residual metering capital costs through an alternative control services annual charge) in March 2015. We received submissions from consumer groups, potential competitive metering providers, retailers and distributors.

would only be replaced if the new meter delivers sufficient additional economic value to cover its own cost and any remaining economic value of the existing regulated meter.

Although we considered that at a theoretical level this option has merit, at a practical level it has substantial shortcomings for a range of reasons. Firstly there is limited information as most distribution businesses do not record information about asset type or age at the individual customer level. Secondly, we are not satisfied that the amount distribution businesses are entitled to recover (based on actual costs) necessarily corresponds to the remaining economic value of a meter. For example, if a meter fails, distributors are still allowed to recover the capital costs that were incurred to provide that meter originally—even though the meter is no longer in service and therefore has no economic value. Also, regulated historic metering costs may not be efficient, as distribution businesses have not faced competitive pressures. Finally, we were concerned that it may be inappropriate to charge customers different exit fees that would vary with meter type and age because such investment decisions were made by distribution businesses, not customers.

Our draft decision involved recovering residual metering capital costs through charges for standard control services based on actual customer switching. These residual capital costs would then be recovered from the general distribution customer base through making a b-factor adjustment to annual revenue requirements, which would have the effect of (all things equal) increasing network tariffs. To mitigate network tariff price volatility that may arise if many customers switched in the one year, we proposed a tolerance limit on the b-factor.<sup>83</sup>

Our draft decision approach received wide support from most stakeholders.<sup>84</sup> Despite having some reservations, NSW distributors largely accepted our draft decision, but did not agree with the operation of the b-factor and the tolerance limit. ActewAGL did not support our approach primarily on the basis that there may be legal concerns on whether our draft decision approach would be permissible under the NER. In particular, whether residual capital costs can be recovered through standard control services in the way proposed. Ergon Energy shared the same concern.<sup>85</sup>

---

<sup>83</sup> AER, Draft decision Ausgrid distribution determination – Attachment 16 Alternative control services, November 2014, p. 46.

<sup>84</sup> Vector Limited, Submission on the AER's Draft Decisions on NSW and ACT Electricity Distributors' Regulatory Proposals for 2015-16 to 2018-19, p. 3.

ERAA, Submission on NSW DNSPs draft decision, 13 Feb 2015, p. 1.

Origin, Submission on NSW draft decisions, 15 Feb 2015, p. 22.

CCP, Submission to AER Responding to NSW draft determination and revised proposals, p.41.

AGL, Submission to AER on NSW electricity distribution network determinations 2014-19: AER draft decisions and revised regulatory proposals, pp.1-3.

TEC, Submission to AER on the draft determination on NSW DB's regulatory proposals 2014-19, Feb 2015, p.2.

NCOSS, Submission to the AER draft determination on NSW distribution business's revised regulatory proposals 2014–19, February 2015, p.7.

<sup>85</sup> Ergon Energy, Submission on the draft decisions: NSW and ACT distribution determinations 2015-16 to 2018-19, p. 35.



In response to the concerns raised, we consulted on alternatives that would not require moving residual capital costs through to the standard control RAB.<sup>86</sup> Our final decision approach is to recover the residual metering capital cost from all customers through an alternative control service. We consider this better meets the national electricity objective and addresses the main concerns raised by the NSW and ACT distributors in the following ways:

- Our final decision does not attempt to classify a category of cost as there are no residual metering capital costs that risk becoming stranded when a customer churns. The relevant service is meter provision (pre 1 July 2015). The costs associated with this service are recovered through the capital component of the regulated annual charge.
- Meter provision (pre 1 July 2015) remains an alternative control service even after a customer churns, it will not be added to the RAB for standard control services.
- Given the above, our final decision will not require additions to the RAB for standard control services during the regulatory control period.
- Our final decision removes any price volatility. The capital component of the annual charge is set for the entire 2015–19 regulatory control period and will only be updated for smoothing X-factors and CPI in accordance with the control mechanism formula. Without any annual adjustments, there is no longer a need for any tolerance limits.

Distributors recover the same amount overall under both our draft and final decision approaches. The difference is which particular customer class pays. Under our draft decision, a switching customer did not directly have to pay for the residual metering capital costs related to their regulated metering service. Instead, residual capital costs would be recovered from all distribution customers through network (DUoS) tariffs, including larger customers who have never received these metering services. Switching customers only indirectly paid for a small fraction of the residual metering capital costs through the increase in network tariffs (the same increase faced by all distribution customers).

This has been amended in our final decision, such that a metering customer switching from the distributor directly shares in the recovery of residual capital costs associated with their past regulated metering service with all other metering customers. They do so by continuing to pay the same capital component of the regulated annual charge as all other metering customers until the MAB is fully depreciated.

Our final decision addresses the NSW businesses concerns because it ensures steady cost recovery without the need for annual corrections through a b-factor adjustment or the application of tolerance limits. It also avoids the potential legal concerns raised by ActewAGL.

---

<sup>86</sup> AER, Consultation paper - Recovering the residual metering capital costs through an ACS annual charge - March 2015

We consider our final decision to have switching customers continue to pay for the capital costs associated with the regulated metering service, on balance, better meets the regulatory objectives under the NEL and NER, than either ActewAGL's initial proposal or our draft decision approach. We considered:

- Impact on competition:
  - The structure and quantum of regulated metering charges impact competitive entry (both upfront exit fees and the regulated annual charge)
  - Like our draft decision, our final decision removes the upfront exit fee which was identified as the primary barrier to competitive entry by stakeholders
  - Like our draft decision, our final decision removes concerns about first mover disadvantage that would arise if the first mover had to pay the upfront exit fee and risk being undercut by another competitive provider that does not face the exit fee. Under the final decision, the customer is charged the capital component of the regulated annual metering charge directly
  - Relative to our draft decision, our final decision increases the costs to switch to a competitive metering provider.<sup>87</sup> A higher switching cost relatively lowers the incentive to switch to a competitive metering provider, so our final decision approach may result in slightly slower uptake of competitive metering services, depending on how compelling an offer is by a competitive metering provider.
- Administrative simplicity:
  - Our final decision makes use of existing information that ActewAGL has, rather than relying on further information on the remaining economic or technical life of individual metering assets which would be difficult to determine
  - It is less complex than the draft decision which involved making annual adjustments to the b-factor and the standard control services RAB. Further, tolerance limits are no longer needed because there will be no price volatility under our final decision approach.
- The directly attributed cost to minimise cross subsidies:
  - Our final decision involves continuing to charge switching customers an ongoing regulated annual charge to recover metering capital costs associated with their past regulated metering service. We considered whether it was appropriate to continue to charge a regulated annual charge when a customer is no longer receiving an active regulated metering service

---

<sup>87</sup> Under our draft decision, a customer who switched only had to pay metering charges related to a competitive metering provider for their new advanced meter and a small proportion of residual metering capital costs through increased DUoS charges. Under our final decision, a customer who switches continues to pay the regulated annual charge (capital), in addition to any new advanced metering charge. The switching cost is therefore higher under our final decision.

We consider that it is appropriate to charge switched customers for fixed capital costs associated with their past regulated metering services because it more directly attributes cost recovery to the customer group that caused those costs to be incurred and ensures that the distributor has an opportunity to at least recover its efficient costs. We consider this also strikes an appropriate balance to promote efficient investment as set out in the revenue and pricing principles

- Our draft decision involved cross subsidising residual costs across the general distribution customer base. For example, the network tariff paid by a large industrial customer who has never used a type 5 or 6 regulated metering service<sup>88</sup> would contribute towards paying off residual metering capital costs associated with switching customers
- Under our final decision, only customers at premises which currently or previously had a type 5 or 6 metering service will be paying for the capital costs incurred in providing type 5 and 6 metering services
- Nonetheless, our final decision still involves some cross subsidy. This is because the capital component of the annual charge is based on the average depreciated value of the MAB. We consider this is appropriate given that we do not have granular information on the customer's specific meter asset type or age
- Another form of cross subsidy is that the regulated annual charge (capital) a switching customer will pay for includes some recovery of forecast replacement capex that is not linked to the switched customer's past regulated metering service. The opening MAB value is based on past capex. The MAB is not forecast to grow much because from 1 July 2015, all new and upgraded meters will be paid for upfront and will therefore not be included in the MAB. However, some forecast capex relating to replacement meters will be added to the MAB.<sup>89</sup> However, this is expected to be an interim issue as it is likely that distributors will not be able to install replacement meters after the metering rule change comes into effect on 1 July 2017<sup>90</sup>
- Our final decision to charge for new and upgraded meters upfront removes the risk of future cross subsidy. This is because by charging capital costs upfront, it is directly attributed and paid for by the customer choosing to install that meter. There is no risk of metering capital costs becoming stranded.

---

<sup>88</sup> Type 5 and 6 metering services are for smaller customers who consume less than 160MWh annually.

<sup>89</sup> Capex related to replacement meters is added to the MAB and recovered from all metering customers through the annual charge, rather than charged upfront. We consider this is appropriate because replacement is not initiated or controlled by the customer. A meter has to be replaced if it suddenly fails or may have to be proactively replaced because the distributor must comply with AEMO's metrology procedures.

<sup>90</sup> AEMC, Expanding competition in metering and related services, Draft Rule Determination, 26 March 2015, p. 79.

Our final decision signals a relatively higher switching cost compared to our draft decision as we explain above. This may result in slower entry by competitive entrants than our draft decision. However, we consider it appropriate that our final decision signals a lower avoidable annual cost for two reasons.

Firstly, the avoidable cost signalled under our final decision is closer to the actual avoidable cost faced by the distributor. Actual avoidable costs are variable costs the distributor no longer incurs when a customer switches. Non-capital costs (for example, meter reading) are largely variable costs. Under our existing regulatory framework, distributors are entitled to recover capital costs incurred in providing regulated metering services. Thus, the recovery of capital costs cannot be avoided even if a customer switches.

Our draft decision therefore signalled a higher than actual avoidable cost to the switching customer, which arguably might promote greater switching than what is efficient. Under the draft decision, the avoidable cost signalled to the switching customer was equal to the entire annual charge (based on both the variable non-capital and fixed capital components). Under the final decision, the avoidable cost is only the variable non-capital component of the annual charge, closer to the true avoidable cost.

Secondly, the impact on competition is not the only regulatory objective. We are required to balance a number of considerations under the NER, including the need for efficient price signals and thus minimising cross subsidies. When making our draft decision, we accepted this cross subsidy (which resulted in the relatively higher avoidable annual costs). This was preferable to the alternative of accepting a large exit fee because of the negative impact on competition. However, we consider that our final decision better balances the various objectives than both our draft decision and the initial proposal from network businesses to charge a high upfront exit fee. Our final decision removes the main barrier to competition (a high upfront exit fee) while being administratively simpler and minimising cross subsidies and therefore leading to a more efficient outcome.

## **Annual metering service charges**

Our final decision is to not accept ActewAGL's total proposed building block requirement for annual metering services. We maintain our draft decision accepting a building block approach to setting charges. We also accept the proposed opening MAB and the revised capex forecast. However, we do not accept the following components of ActewAGL's proposal:

- forecast opex
- adoption of accelerated 9 year, depreciation.

We therefore substitute ActewAGL's proposed annual metering service charges, with those set out in Appendix A.

## Opening metering asset base and depreciation

Our final decision is to maintain our draft decision to accept ActewAGL proposed opening MAB as at 1 July 2014 of \$50.04 million (\$ nominal).<sup>91</sup>

### Depreciation

We do not accept the standard asset lives proposed by ActewAGL. It proposed an accelerated depreciation approach with the aim of recovering the residual value of all existing meters over 9 years. With the opening of competition in the provision of metering services, this was intended to remove legacy assets from the MAB within two regulatory control periods.<sup>92</sup>

We do not consider that ActewAGL's proposed accelerated 9 year depreciation is efficient. It is unlikely that all meters will be provided by alternative service providers within 9 years. At that time, under ActewAGL's proposal, all existing meters will be fully depreciated but still providing services. This is not an efficient long term outcome. We consider that the metering asset lives should continue to reflect the technical lives of the meters.

We therefore substitute ActewAGL's revised accelerated depreciation profile with 15 year standard asset lives. This substitute standard asset life reflects the technical lives of ActewAGL's type 5 and 6 meters.

We confirm that forecast (as opposed to actual) depreciation will apply to ActewAGL's MAB.

### Forecast capex

We accept ActewAGL's revised capex proposal of \$13.0 million (\$2014–15). It incorporates a change in capitalisation policy for new or upgraded connections, which our draft decision included.<sup>93</sup> This amount is a reduction from ActewAGL's initially proposed \$33.2 million (\$2014–15).<sup>94</sup>

Table 16.14 sets out ActewAGL's revised capex proposal and our final decision. For each cost category, we have accepted ActewAGL's revised proposal.

**Table 16.14 – Proposed and substitute capex for metering annual services (\$ million 2014–15)**

	Revised proposal	Adjustment (unit costs)	Adjustment (volume forecast)	Final decision
New or upgraded connections (2014–	4.6	0.0	0.0	4.6

<sup>91</sup> AER, *Draft decision on ActewAGL's regulatory proposal: 2014-15 and 2015-19*, November 2014, p. 16–34.

<sup>92</sup> ActewAGL, *Revised regulatory proposal 2015-19*, January 2015, p. 662.

<sup>93</sup> AER, *Draft decision on ActewAGL's regulatory proposal: 2014-15 and 2015-19*, November 2014, p. 16–29.

<sup>94</sup> ActewAGL, *Initial regulatory proposal, Attachment B8, Metering PTRM*, May 2014. Converted to \$2014–15.

	Revised proposal	Adjustment (unit costs)	Adjustment (volume forecast)	Final decision
15 only)				
Replacements	8.3	0.0	0.0	8.3
Total	13.0	0.0	0.0	13.0

Source: ActewAGL, *Revised regulatory proposal 2015–19, H10 - PTRM Modelling*, January 2015. Converted to \$2014-15.

### Unit costs

We approve ActewAGL's proposed unit costs. This follows information in ActewAGL's revised proposal, clarifying its jurisdictional requirements with respect to the installation of certain meters.

In our draft decision, we engaged Marsden Jacob to assist our assessment of ActewAGL's forecast material unit costs. This involved the consultant considering the 'maximum rate that should be applied for each meter hardware category based on consideration of the rates applied across the business and a comparison against current market rates'.<sup>95</sup> These rates were sourced from online advertised prices and through direct engagement with major suppliers.<sup>96</sup> Based on this information and advice our draft decision was to:

- accept ActewAGL's proposed unit costs for type 5 meters, as these were within the observed market range<sup>97</sup>
- adjust the proposed unit costs for type 6 meters, as these were found to be above the observed market range. We adjusted these unit costs, bringing them to what we considered to be prudent and efficient.<sup>98</sup>

Since our draft decision, ActewAGL has provided additional information about the meter types it is required to install. Specifically, it stated that 'under the current jurisdictional requirements all new, upgrade and replacement meters must be type 5 meter (not type 6)'.<sup>99</sup> ActewAGL stated that we should accept its proposed material unit costs, in light of these jurisdictional requirements. This is given that the only type of meters which ActewAGL is able to install (type 5) was considered to be within Marsden Jacob's observed market ranges.

<sup>95</sup> Marsden Jacobs Associates, Consultant report to the AER on Alternative Control Services, October 2014, section 2.1.1.

<sup>96</sup> Marsden Jacobs Associates, Consultant report to the AER on Alternative Control Services, October 2014, section 2.1.1.

<sup>97</sup> AER, *Draft decision on ActewAGL's regulatory proposal: 2014-15 and 2015–19*, November 2014, p. 16–29.

<sup>98</sup> AER, *Draft decision on ActewAGL's regulatory proposal: 2014-15 and 2015–19*, November 2014, p. 16–29.

<sup>99</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 661.

We agree with ActewAGL. The distributor must install type 5 meters only.<sup>100</sup> Since Marsden Jacobs found that ActewAGL's material unit costs for type 5 meters were within the observed market ranges,<sup>101</sup> it follows that they should be approved. For those reasons, our final decision is to accept ActewAGL's forecast material unit costs for each type of meter.

### Forecast volumes

We maintain our draft decision accepting ActewAGL's forecast volumes of new or upgraded connections and replacements. Our reasoning is set out in our draft decision.<sup>102</sup>

Our final decision accepts a single year (2014–15) of forecast volumes for new or upgraded connections. This is in line with our position that from 1 July 2015 the cost of all new or upgraded connections should be recovered via upfront charges, rather than the annual metering charge (see section 16.2.2). It is also consistent with ActewAGL's revised proposal, which did not include any forecast volumes for new or upgraded connections beyond the 2014–15 year. Additionally, we maintain our draft decision accepting ActewAGL's replacement forecast. It is supported by data showing that many of its meters have exceeded their technical life.<sup>103</sup> Table 16.15 shows the volumes we have approved.

**Table 16.15 – Approved volumes of meters for new/upgraded connections, reactive replacements, and proactive replacements (per meter)**

	Volume
New and upgraded connections (2014–15 only)	8 150
New photovoltaic meters	550
Replacements	18 250

Source: AER analysis

<sup>100</sup> Independent Competition and Regulatory Commission, Final decision: Review of metrology procedures, December 2005, p. 31.

<sup>101</sup> Marsden Jacobs Associates, Consultant report to the AER on Alternative Control Services, October 2014, section 2.1.1.

<sup>102</sup> AER, *Draft decision on ActewAGL's regulatory proposal: 2014–15 and 2015–19*, November 2014, p. 16–30.

<sup>103</sup> ActewAGL, *Regulatory proposal, Attachment D6: Meter asset management plan*, Version 2.25, 27 May p. 14.

## Forecast opex

We accept \$11.1 million in opex for annual metering services and substitute that amount for ActewAGL's proposal. Our substitute is approximately 31 per cent lower than the \$16.1 million (\$2014–15) in ActewAGL's revised regulatory proposal.

## Base

To assess this, we observed ActewAGL's opex over a five year period (2008–09 to 2012–13). This is the same approach we applied in the draft decision but different to how ActewAGL developed its base; which involved using a single year of opex (2012–13).<sup>104</sup>

We also applied a multi-year approach to determine base opex in our draft decision. ActewAGL's revised proposal stated that this was not justified since the AER had not shown that the proposed base year (2012–13) was inefficient.<sup>105</sup>

We nonetheless consider our multi-year approach to be more robust than ActewAGL's single year method. By taking multiple years of costs into account, we avoid any incentive on ActewAGL, going forward, to load a single year with expenditure. This is important given that we do not apply an efficiency benefit sharing scheme with respect to alternative control metering services.

Consistent with our approach for standard control services, we further examined the proposed base from another perspective by applying benchmarking. To do this we used a partial performance indicator which compared ActewAGL's proposed opex per customer against other non-Victorian distribution businesses in the national electricity market.

When comparing ActewAGL's proposed opex to its peers, we normalised our results by accounting for customer density. We calculated this as the number of customers a distribution business has per kilometre of line length. We took customer density into account because, all things equal, businesses with a low customer density are likely to require higher opex. For example, this could be because of longer travel times to service customers.

We considered stakeholder submissions. These included a report from the accountancy firm PriceWaterhouseCoopers (PWC). This report, which ActewAGL commissioned, stated that the data we used to perform our benchmarking did not take into account the 'differing treatment... of metering costs depending on jurisdictional requirements'.<sup>106</sup> However, we did account for differences across jurisdictions when selecting what data to perform our analysis.

---

<sup>104</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 662.

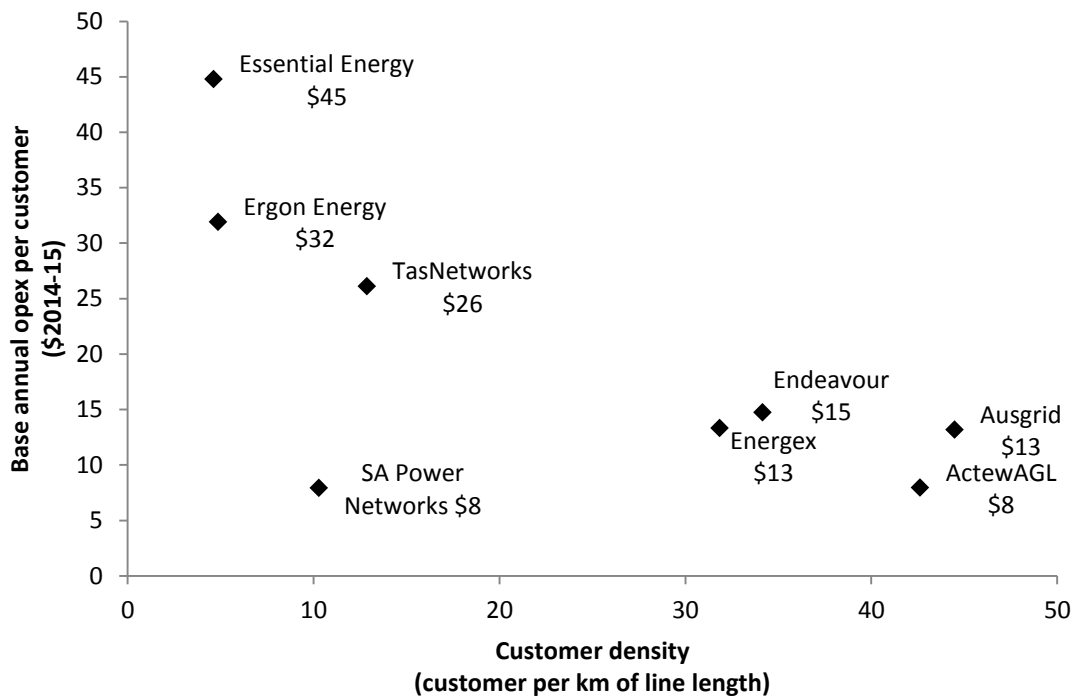
<sup>105</sup> ActewAGL, *Revised regulatory proposal 2015–19*, January 2015, p. 662.

<sup>106</sup> ActewAGL Distribution, Submission on the draft decision, February 2015, p 17



We excluded data from Victorian distributors in recognition that Victoria is the only state that had a mandated advanced meter roll out. We further accounted for jurisdictional differences in our final decision by adjusting historic data for metering opex to exclude ancillary metering activities (such as special meter reading). We did this because the classification for these services differs across jurisdictions. The benchmarking analysis now compares like for like by only including opex for default metering services that is common across jurisdictions. Therefore, we consider that our final decision analysis has appropriately taken into account different jurisdictional requirements.

**Figure 16.5 – Benchmarking of annual default metering opex per customer (\$ 2014–15)**



Source: AER analysis.

Figure 16.5 sets out the results of our benchmarking. It shows that, firstly, Ausgrid is ActewAGL's closest comparator for benchmarking purposes. Both these businesses have a similar customer density. Our benchmarking also shows that ActewAGL is relatively efficient compared to its NSW counterpart. Specifically, ActewAGL incurs less opex per metering customer than Ausgrid. This is despite the latter having a denser distribution network.

We conclude that ActewAGL's historical opex is relatively efficient. Consequently, our final decision does not apply an efficiency adjustment to ActewAGL's base opex, on

the basis of our benchmarking results. This outcome is consistent with our draft decision.<sup>107</sup>

### **Step changes**

We maintain our draft decision to accept approximately \$0.8 million (\$2014–15) for the proposed step change relating to ActewAGL’s cost allocation method.<sup>108</sup> The step change is required because ActewAGL will begin allocating overheads directly to projects, in accordance with the cost allocation method we approved for the 2014–15 and 2015–19 regulatory control periods.

We also maintain our draft decision to not approve the proposed \$0.9 million (\$2014–15) step change relating to the visual inspection of low voltage CT meters. Step changes relate to either capex/opex trade-offs or a new regulatory obligation.<sup>109</sup> It is not enough to simply demonstrate an efficient cost will be incurred for an activity that was not previously undertaken. With that in mind, we note that the requirement to inspect the CT meters is not a new obligation. ActewAGL’s metering asset management plan states that the distribution business was scheduled to conduct the inspections of all CT meters in 2008.<sup>110</sup> We therefore do not accept the proposed step change as it is a continuing obligation.

### **Trend**

We trended the base forward for forecast metering customer growth. Consistent with our draft decision, we have applied zero forecast real price and productivity growth.

Our analysis for base metering opex used average data from 2008–09 to 2012–13. One would expect to see metering opex per customer increasing over the period if there was real price growth.

---

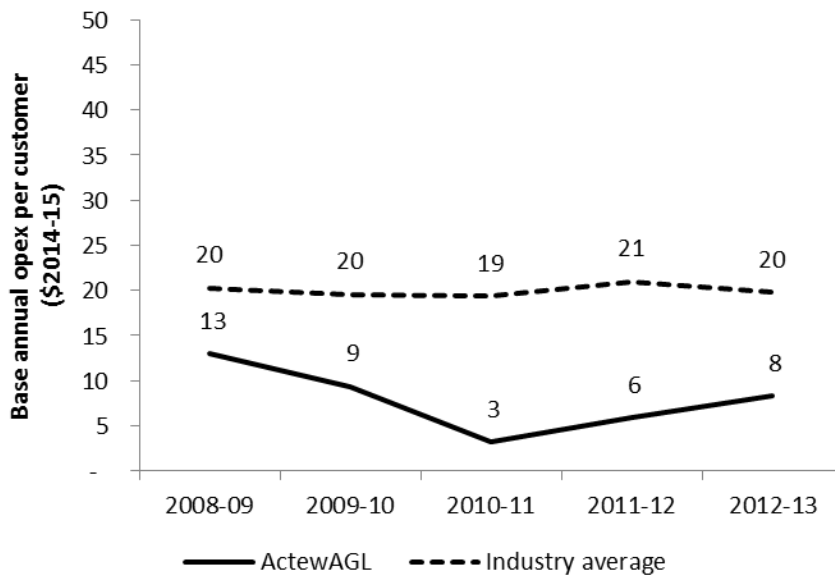
<sup>107</sup> AER, *Draft decision on ActewAGL’s regulatory proposal: 2014–15 and 2015–19*, November 2014, p. 16–32.

<sup>108</sup> AER, *Draft decision on ActewAGL’s regulatory proposal: 2014–15 and 2015–19*, November 2014, p. 16–33.

<sup>109</sup> AER, *Expenditure assessment guidelines*, November 2013, p. 11.

<sup>110</sup> ActewAGL, *Meter Asset Management Plan, Version 2.5*. 27 May 2014, p. 14.

**Figure 16.6 – Base annual opex per customer**



Source: AER analysis

However, Figure 16.6 shows that over 2008–09 to 2012–13, ActewAGL's metering opex per customer was not steadily increasing while the industry average was stable over the period. This implies that either there were no real price increases over this period, or the distributors were able to offset these real price increases with productivity improvements.

Given that opex is largely recurrent and metering opex per customer did not increase over the 2008–09 to 2012–13 period, we do not forecast metering opex per customer to increase in the 2015–19 regulatory control period. Therefore, we apply zero real price and productivity growth.

Our alternative forecast accepts 69 percent of what ActewAGL proposed. Our final decision is principally driven by our assessment that ActewAGL's historical opex is relatively efficient. We consider this to be reasonable, since in providing metering services ActewAGL should, at the very least, be as efficient as it has been in the past. For that reason, we consider our substitute opex forecast reflects ActewAGL's likely future requirements.

## **Upfront capital charge**

We accept that all new or upgraded meters initiated by a customer be recovered through an upfront charge. We also accept each of the proposed upfront capital charges.

The unit costs ActewAGL proposed for upfront capital charges are the same as those set out in our assessment of ActewAGL capex building block for the annual metering service charge. Since we assessed those unit costs to be efficient, we approve them in relation to the upfront capital charge as well.

We have determined that the upfront capital charge should be annually adjusted for labour price changes. In coming to this conclusion, we note that our final decision has determined that ancillary service fees will be subject to such annual adjustments. The upfront capital charge recovers similar costs to ancillary services fees. It follows that labour price changes should be accounted for in our price control for the upfront capital charge. We have done this in our control mechanism decision in section 16.2.1 above.

Not all of the costs associated with the upfront capital charge relate to labour. To take this into account, when making our price control decision we have used a weighted X-factor. Specifically, we observed that about 60 percent of the costs relating to the upfront capital charge are attributable to labour. In setting the X-factor, we therefore applied a weighting of 60 percent to the labour price changes, which we have forecast in this final decision.<sup>111</sup>

## Meter exit fee

Our final decision to continue charging switched customer for the capital component of the annual metering charge. Therefore, there is no risk of stranded assets that need to be recovered through an exit fee.

We do not approve ActewAGL's proposal to recover administration costs relating to customers transferring to alternative metering providers through an exit fee. We find that there are no additional tasks or functions these distributors will have to assume when customers change meter provider. Thus there are no incremental costs.

In assessing all distributors' proposed meter transfer fees, our main focus is on the types of activities that are undertaken by retailers, distributors and metering providers in the National Electricity Market when a customer churns from a distributor owned meter. We also looked at the methodologies distributors adopted to establish the fee. Furthermore, because there is an alternative provider to that of the distributor, those providers' approach to dealing with customer meter churn and any associated costs should provide a direct comparator for that of the monopoly business.<sup>112</sup>

Retailers submitted that any activities undertaken by the distributors was no different from existing data entry/system management functions undertaken as part of normal business practice and that any incremental costs associated with 'administration' would be absorbed by the entity acquiring the metering customer.<sup>113</sup>

---

<sup>111</sup> See attachment 2 of this final decision for more information on how changes in labour costs were forecast.

<sup>112</sup> Retailers in the National Electricity Market can and do provide metering services to the contestable elements of the market, namely the medium and large businesses. Distributors at this stage maintain a monopoly provision to household customers but this will change with advent of the AEMC competition in metering rule change.

<sup>113</sup> Vector Limited, submission on the AER's draft decision on New South Wales and ACT Electricity Distributors' Regulatory Proposals for 2015–16 to 2019–20, pp. 5, 6-8, 13 February 2015, p.p. 6-7; AGL, Alternative approach to the recovery of the residual metering capital costs through an alternative control service annual charge, 27 March 2015, p.2; AGL, email to AER staff, AGL Presentation to AER staff—metering regulation & transition to competition, 13 March 2015.

Oakley Greenwood, in its report to Origin Energy corroborated stakeholders views by contending that changing information in the distributors systems, is likely limited to a change in information about the entity that is responsible for the meter; the identity of the metering coordinator; and sufficient information about meter type to enable its verification for tariff assignment, was probably all that was required.<sup>114</sup>

We tested this with retailers, many of whom are already providing metering services to large customers, which is a contestable market. Simply Energy did not agree with the imposition of administration fees; nor did Origin Energy. The latter was concerned that all three NSW distributors used vastly different inputs and therefore required testing against efficient benchmarks before a reasonable costs could be determined.<sup>115</sup> The retailer considered that a consistent approach to the calculation of administrative costs was most appropriate.<sup>116</sup>

Simply Energy observed its current role in churning meters (type 4) in the competitively provided commercial market involved administrative transaction costs that were immaterial to it. It also advised that distributors were not currently charging them a meter transfer fee where the customer switched from the distributor to the retailer as metering provider.<sup>117</sup>

Commenting on the New South Wales distributors' proposals, Simply Energy stated that there appeared no assumption of batch processing. Instead, the proposed charges assumed each meter was being processed individually. Simply Energy noted that if put in the position of the distributors, it would review processes in detail to determine the optimum batch size, which would be at least 20 meters (i.e. customers) per batch.<sup>118</sup> In such circumstances, multiplying Endeavour Energy's proposed five minutes per meter by 20 minutes equates to 100 minutes per batch for each manual process. Simply Energy proposed that 10 minutes was a more credible time.<sup>119</sup> This was also appropriate for other distributors.

Furthermore, Simply Energy advised that the reasonable activities it would have to incur to process a batch of 20 meters and the time taken for each were:

- Meter provider database update—10 minutes
- Banner system meter update—25 minutes
- Metering business system update—25 minutes

---

<sup>114</sup> Oakley Greenwood, Review of NSW DBs Regulatory Submission, 8 August 2014, p. 7 in Origin Energy, Submission to NSW Electricity distributors' regulatory proposals, 8 August 2014, (attachment 2).

<sup>115</sup> Origin Energy, Ausgrid, Endeavour, Essential initial 2015–19 initial regulatory proposals, Origin submission, August 2014, (attachment 1) p. 36.

<sup>116</sup> Origin Energy, Ausgrid, Endeavour, Essential initial 2015–19 initial regulatory proposals, Origin submission, August 2014, (attachment 2), p. 7.

<sup>117</sup> Meeting between respective staff of Simply Energy and AER on 16 March 2015.

<sup>118</sup> Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

<sup>119</sup> Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

- Banner system final read update—10 minutes.<sup>120</sup>

This amounts to 70 minutes for a batch of 20 meters; or a total time per meter of 3.5 minutes. This is substantially less than the times proposed by any of the distributors. Given this, Simply Energy submitted that the imposition of a meter transfer fee in the residential metering market of the magnitude distributors had proposed was not justified. Rather, Simply Energy argued that the administrative costs are negligible.

Retailers, as the acquirers of a new meter customer, bear the costs of acquisition and must provide all relevant information to the entity that has lost the customer, in this case the distributor. This includes attending the site, removing the meter and sending it to the distributor's depot or alternative location. The retailer has an incentive to keep those costs down and to work with the business that has lost the customer—be they distributors or other retail rivals once a competitive market is established—to ensure smooth market operation. This has been the case since inception of the national electricity market for large customers. We do not find that the costs proposed by the distributors are reflective of this cost minimisation incentive.

This is confirmed by the Australian Energy Market Operator who has a new set of meter churn procedures due to commence September 2015.<sup>121</sup> This new procedure simplifies the meter churn procedure and places the onus on the Financial Responsible Market Participant (as the incoming Responsible Person) and its Metering Provider to update Market Settlement and Transfer Solutions and administer the transfer. The distributor's role is minimised, especially for the displacement of Type 6 legacy meters. Type 5 meters will require a final read. It could be expected that competing meter providers will be sufficiently encouraged to work with distributors to provide them with the necessary final read data. This is because to do otherwise will reduce their profit margins and potentially put them at risk of failing to meet their obligations to provide relevant data to ensure market settlement in a timely manner.<sup>122</sup> It is reasonable to assume that the new meter churn procedures will carry forward into the residential metering market, the competitive metering element of which is now in its infancy.

As a metering provider with experience in competitive metering markets, Vector commented on Endeavour Energy's cost assumptions in its revised revenue proposal. These are reproduced in Table 16.16 where both organisations responses can be compared.

---

<sup>120</sup> Simply Energy, metering question and churning, email to AER staff, 23 March 2015.

<sup>121</sup> See <http://www.aemo.com.au/Consultations/National-Electricity-Market/Second-Stage-Notice-of-Consultation--Meter-Churn-Package>, accessed 26 March 2015 and <http://www.aemo.com.au/Consultations/National-Electricity-Market/~media/Files/Other/consultations/gas/Churn%20Package%202014/Meter%20Churn%20Procedure%20FRMP%20v10%20clean.ashx> accessed 26 March 2015.

<sup>122</sup> We are aware of instances where some distributors are alleged to have deliberately stalled or frustrated attempts by large commercial users to switch meter provider. However, this is a separate issue of specific business conduct, rather than of efficient billing systems per se.

**Table 16.16 Endeavour Energy meter transfer fee build up and Vector response**

Endeavour Energy Task	Endeavour Energy Time	Vector Comment
Administration Officer updates the meter removal in the Meter Provider Database.	5 min	Valid distributor activity that is currently carried out regularly now. Could not be delivered by Metering Service Provider but could be automated via distributor integration to market systems
Network Billing Data Analyst updates the meter removal and the new metering details (for the non-Endeavour Energy asset) in the Banner billing system.	5 min	Valid distributor activity that is currently carried out regularly. Could not be delivered by Metering Service Provider but could be automated by distributor via integration to market systems
Network Billing Data Analyst updates the new metering details in the Metering Business System (MBS), which will allow network billing activities to occur.	5 min	Valid distributor activity that is currently carried out regularly. Could not be delivered by Metering Service Provider but could be automated by distributor via integration to market systems
Metering Officer obtains the final read for the meter and inputs the details of the final read into Banner billing system.	5 min	Valid distributor activity that is currently carried out regularly
The ASP returns the Endeavour Energy removed asset back to the designated Endeavour Energy depot. Endeavour Energy process dictates that the meter is double bagged and goose necked to ensure safe transportation of asbestos contaminated materials. The consumables required to meet these requirements are supplied by Endeavour Energy.		Metering Service Provider could carry out on behalf of the distributor if permitted by latter. Metering Service Providers anticipate funding this activity themselves.
Cost of meter disposal.		Metering Service Provider could carry out on behalf of the distributor if permitted by latter. Metering Service Providers anticipate funding this activity themselves.

Source: Endeavour Energy; Vector Limited.

Vector advised that its response to the activities listed in Table 16.16 was that the tasks were not unique to distributors. Alternative meter service providers can now, and will in the future, undertake many of these tasks. Furthermore, it noted that Endeavour Energy could integrate these activities and tasks with electronic transactions that it presently receives from AEMO.<sup>123</sup> Vector says this is how it operates in the market today and did not see why distributors should not do the same. Given that distributors were performing these functions now as standard business practice, Vector could not anticipate what incremental costs would arise as a result of competitive metering.<sup>124</sup>

<sup>123</sup> Vector Limited, Urgent - meter churn procedures, email to AER staff, 20 April 2015.

<sup>124</sup> Vector Limited, Urgent - meter churn procedures, email to AER staff, 20 April 2015

We do not agree with the distributors' position that that an increase in staff will be required within the regulatory periods commencing 1 July 2015. We also consider that it will be the meter service provider, as the financially responsible market participant, who will bear the additional costs associated with meter churn, not the distributors.

We find that customers would not be paying an efficient level of costs for meter churn if the distributors' proposed transfer fees were approved. A meter transfer fee of the order proposed by ActewAGL (\$30.79) could amount to a de-facto exit fee that would act as a barrier to competition and the uptake of new advanced meters. While the NEL requires us to ensure distributors have the opportunity to recover at least their efficient costs we are not persuaded by the evidence that distributors have material incremental costs to recover in amending records to take account of customer churn. Any incremental costs will be borne by the acquirer of the new meter customer—at the moment, retailers. Furthermore it is noteworthy that distributors are churning type 6 meters for interval meters for customers installing Solar Photovoltaic systems in large numbers without imposing any administrative fees for the meter transfer.

Further support to our findings that the proposed transfer fees are disproportionate to the activities to be undertaken is in comparing the per customer meter opex fee which we have approved in this decision. Our final decision will see ActewAGL recover \$8 annually for metering opex per customer for meter data services, truck rolls, reading and processing, a share of information technology costs and including overheads. It does not follow that a proposed transfer fee greater than this is reasonable.<sup>125</sup>

We do not approve a meter transfer fee for the regulatory control period commencing 1 July 2015.

## **Control mechanism**

Consistent with our draft decision, we have applied zero X-factors for the annual metering charges. We assessed whether real price escalation was required as part of our building block revenue assessment. It is therefore not necessary to consider whether real price escalators should apply through the X-factors.

However, we have included different X-factors for the upfront capital charges. This is to allow for real labour escalation.

In response to its revised proposal, we have confirmed how ActewAGL is to show compliance with the control mechanism through the annual process.

---

<sup>125</sup> This logic also applies if we take the ActewAGL's proposed average metering opex per customer per year of \$19.



## A Appendix

### A.1 Final Decision charges for alternative control services

#### A.1.1 Ancillary network service charges

**Table 16.17: ActewAGL, ancillary network service charges for first year of regulatory control period (\$2014–15)**

Service name	ActewAGL revised proposed 2015-16 prices (\$2014-15)	AER final decision 2015-16 prices (\$2014-15)	Percentage change (AER final decision cf. revised proposed charge)
<b>Premise Re-energisation – Existing Network Connection</b>			
Re-energise premise – Business Hours	64.47	64.47	0.0
Re-energise premise – After Hours	81.71	81.71	0.0
<b>Premise De-energisation – Existing Network Connection</b>			
De-energise premise – Business Hours	64.47	64.47	0.0
De-energise premise for debt non-payment	128.93	128.93	0.0
<b>Meter Reconfiguration</b>			
Install Interval Meter		See: Table 16.22	
Install subsequent meter - at same location during same visit (excludes cost of meter)		See: Table 16.22	
Install / Replace Meter – Micro Renewable Energy Installation		See: Table 16.22	
Single phase, single element manually read interval meter		See: Table 16.22	
Single phase, two element meter		See: Table 16.22	
Three phase meter		See: Table 16.22	
<b>Meter Investigations</b>			
Meter Test (Whole Current) – Business Hours	257.86	257.86	0.0

Service name	ActewAGL revised proposed 2015-16 prices (\$2014-15)	AER final decision 2015-16 prices (\$2014-15)	Percentage change (AER final decision cf. revised proposed charge)
Meter Test (CT/VT) – Business Hours	306.79	298.64	-2.7
<b>Special meters Services</b>			
Special Meter Read	37.98	29.82	-21.5
Meter exit fee (recovery of meter asset value)	274.62	274.62	0.0
Metering transfer admin fee (transfer to another metering provider)	30.79	22.64	-26.5
<b>Temporary Network Connections</b>			
Temporary Builders' Supply – Overhead (Business Hours)	579.43	579.43	0.0
Temporary Builders' Supply – Underground (Business Hours)	1264.93	1264.93	0.0
<b>New Network Connections</b>			
New Underground Service Connection – Greenfield	0.00	No Charge	0.0
New Overhead Service Connection – Brownfield (Business Hours)	761.01	761.01	0.0
New Underground Service Connection – Brownfield from Front	1264.93	1264.93	0.0
New Underground Service Connection – Brownfield from Rear	1264.93	1264.93	0.0
<b>Network Connection Alterations and Additions</b>			
Overhead Service Relocation – Single Visit (Business Hours)	726.35	726.35	0.0
Overhead Service Relocation – Two Visits (Business Hours)	1452.70	1452.70	0.0
Overhead Service Upgrade – Service Cable Replacement Not Required	726.35	726.35	0.0
Overhead Service Upgrade – Service Cable Replacement Required	761.01	761.01	0.0
Underground Service Upgrade – Service Cable Replacement Not Required	1230.27	1230.27	0.0
Underground Service Upgrade – Service Cable Replacement Required	1264.93	1264.93	0.0
Underground Service Relocation –	1264.93	1264.93	0.0

Service name	ActewAGL revised proposed 2015-16 prices (\$2014-15)	AER final decision 2015-16 prices (\$2014-15)	Percentage change (AER final decision cf. revised proposed charge)
<b>Single Visit (Business Hours)</b>			
Install surface mounted point of entry (POE) box	584.99	584.99	0.0
<b>Temporary De-energisation</b>			
Temporary de-energisation – LV (Business Hours)	386.80	386.80	0.0
Temporary de-energisation – HV (Business Hours)	386.80	386.80	0.0
<b>Supply Abolishment / Removal</b>			
Supply Abolishment / Removal – Overhead (Business Hours)	544.76	544.76	0.0
Supply Abolishment / Removal - Underground (Business Hours)	984.21	984.21	0.0
<b>Miscellaneous Customer Initiated Services</b>			
Install & Remove Tiger Tails – Establishment (Business Hours)	1279.28	1279.28	0.0
Install & Remove Tiger Tails - Per Span (Business Hours)	644.00	644.00	0.0
Install & Remove Warning Flags – Installation (Business Hours)	1089.53	1089.53	0.0
Install & Remove Tiger Tails - Per Span (Business Hours)	552.00	552.00	0.0
<b>Embedded Generation - Operational &amp; Maintenance Fees</b>			
Small Embedded Generation OPEX Fees - Connection Assets			
Small Embedded Generation OPEX Fees - Shared Network Asset			
<b>Connection Enquiry Processing - PV Installations*</b>			
PV Connection Enquiry – LV Class 1 (<= 10kW Single Phase / 30kW Three Phase)	0.00	0.00	0.0
PV Connection Enquiry – LV Class 2 to 5 (> 30kW <= 1500kW Three Phase)	529.62	529.62	0.0
PV Connection Enquiry – HV	1059.23	1059.23	0.0

Service name	ActewAGL revised proposed 2015-16 prices (\$2014-15)	AER final decision 2015-16 prices (\$2014-15)	Percentage change (AER final decision cf. revised proposed charge)
Provision of Data for Network technical study for large scale installations	10,592.32	10,592.32	0.0
<b>Network Design &amp; Investigation / Analysis Services - PV Installations†</b>			
Design & Investigation - LV Connection Class 1 PV (<= 10kW Single Phase / 30kW Three Phase)	0.00	0.00	0.0
Design & Investigation - LV Connection Class 2 PV (> 30kW and <= 60kW Three Phase)	3530.77	3530.77	0.0
Design & Investigation - LV Connection Class 3 PV (> 60 kW and <= 120kW Three Phase)	5296.16	5296.16	0.0
Design & Investigation - LV Connection Class 4 PV (> 120 kW and <= 200kW Three Phase )	7061.55	7061.55	0.0
Design & Investigation - LV Connection Class 5 PV (> 200kW and <= 1500kW Three Phase) – ActewAGL Network Study	10,592.32	10,592.32	0.0
Design & Investigation - HV Connection Class 5 PV (> 200kW and <= 1500kW Three Phase) – Customer Network Study	13,240.40	13,240.40	0.0
<b>Rescheduled Site Visits</b>			
Rescheduled Site Visit – One Person	128.93	128.93	0.0
Rescheduled Site Visit – Service Team	544.76	544.76	0.0
<b>Rescheduled Site Visits</b>			
Trenching - first 2 meters	494.50	494.50	0.0
Trenching - subsequent meters	115.00	115.00	0.0
<b>Rescheduled Site Visits</b>			
Under footpath	897.00	897.00	0.0
Under driveway	1069.50	1069.50	0.0

Source: AER analysis

**Table 16.18: AER final decision labour rates (including on costs and overheads)**

Labour classification	Corresponding Marsden Jacob labour category	AER final decision 2015–16 labour rates (incl. on costs and overheads) (\$ per hour, \$2014–15)
Electrical Worker	technical	confidential
Electrical Worker - Labourer	field worker	confidential
Electrical Apprentice	field worker	confidential
Office Support_Service Delivery	administration	89.06
Project Officer_Design Section	engineer	confidential
Senior Technical Officer/Engineer_Design Section	senior engineer	confidential

Source: ActewAGL, *Revised regulatory proposal*; Marsden Jacob report Marsden Jacob Associates, Email advice to the AER, 1 October 2014; AER, Final decision

**Table 16.19: AER labour escalation X factor (percentage)**

	2015–16	2016–17	2017–18	2018–19
labour escalation factor	-0.76	-1.13	-1.22	-1.22

Source: AER analysis.

Note: The exceptions single phase, single element manually read interval meter; single phase two element meter and three phase meter. All these have an X factor of zero. To be clear, labour escalators themselves are positive for each year of the regulatory control period. However, the labour escalators in this table are operating as de facto X factors. Therefore, they are negative.

## A.1.2 Metering

**Table 16.20 ActewAGL – Annual metering charges**

Tariff class	Costs	2015/16	2016/17	2017/18	2018/19
MP1: Quarterly basic metering rate	Non-capital	13.59	13.91	14.24	14.58
	Capital	27.56	28.22	28.89	29.58
MP2: Monthly basic metering rate	Non-capital	23.77	24.34	24.92	25.51
	Capital	48.21	49.36	50.54	51.74
MP3: TOU metering rate (monthly)	Non-capital	23.77	24.34	24.92	25.51
	Capital	48.21	49.36	50.54	51.74
MP4: Monthly manually-read interval metering rate	Non-capital	191.89	196.45	201.13	205.92
	Capital	389.20	398.46	407.94	417.65
MP5: Internal metering rate	Non-capital	23.77	24.34	24.92	25.51
	Capital	48.21	49.36	50.54	51.74
MP6: Quarterly manually read interval metering rate	Non-capital	54.73	56.04	57.37	58.74
	Capital	111.02	113.66	116.36	119.13

**Table 16.21 ActewAGL – Annual metering charges X-factors (percent)**

	2016–17	2017–18	2018–19
X factor	0.0	0.0	0.0

Source: AER analysis.

**Table 16.22 ActewAGL – Upfront charges**

Meter type	Charge (\$ 2014–15)
<u>Initial meter</u>	
Single phase, single element manually read interval meter	488.76
Single phase, two element meter	594.39
Three phase	715.70
<u>Subsequent meter</u>	
Single phase, single element manually read interval meter	308.99
Single phase, two element meter	414.62
Three phase	535.93

Source: AER analysis

Note 1: All charges include the cost of a meter and its installation.

Note 2: The approved charges include standard and micro-renewable energy installations.

**Table 16.23 ActewAGL – Upfront charges X-factor (percent)**

	2015–16	2016–17	2017–18	–042018–19
X factor	–0.45	–0.68	–0.73	–0.73

Source: AER analysis.