FINAL DECISION
SA Power Networks determination 2015–16 to 2019–20

Attachment 16 – Alternative control services

October 2015

AUSTRALIAN ENERGY REGULATOR

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

Note

This attachment forms part of the AER's final decision on SA Power Networks' 2015–20 distribution determination. It should be read with all 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

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Contents

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

Shortened form	Extended form
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
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 that we determined for 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.

The only categories of SA Power Networks' services which have been given an alternative control classification relate to 'type 5 and 6 metering services' and 'exceptional large customer metering services'.[1] This section describes our determination on the charges that SA Power Networks can levy customers for the provision of those services.

16.1 Metering

Our final decision on SA Power Networks' metering proposal is made in the context of ongoing policy reform. We based our assessment on the National Electricity Rules (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.[2]

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.[3] It provides 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'.[4] 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

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1 AER, *Final Framework and Approach for SA Power Networks*, April 2014, p. 54; AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–7.

2 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).

3 AEMC, *Draft rule determination: Expanding competition in metering and related services,* 26 March 2015.

4 AEMC, *Draft rule determination: Expanding competition in metering and related services,* 26 March 2015, p. 225.

- 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.[5]

The AEMC's final determination is due 26 November 2015.[6] In making our final decision, we have taken the AEMC's draft determination into account. In doing so we have sought to establish a regulatory framework for the 2015–20 regulatory period which will be robust enough to handle the transition to competition once the rule change takes effect from 1 December 2017.[7] This involves having transparent standalone prices for all new or upgraded meter connections and annual charges.

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 preliminary decision was that switching customers continue to pay the capital cost component of the regulated annual metering service charge. We have maintained that approach in our final decision.

16.2 Final decision

16.2.1 Structure of metering charges

We classify type 5 and 6 metering services as alternative control services. Our final decision is that 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.

Appendix B outlines in more detail how our approved structure of metering charges will work.

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5 AEMC, *Draft rule determination: Expanding competition in metering and related services,* 26 March 2015, p. iii.

6 AEMC, *Information: Extension of time for final rule on provision of metering services*, 2 July 2015.

7 AEMC, *Information: Extension of time for final rule on provision of metering services*, 2 July 2015.

16.2.2 Annual metering charges

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

- Opening metering asset base

  We accept SA Power Networks revised opening metering asset base (MAB) value as at 1 July 2015 of $84.8 million ($nominal).

- Depreciation

  We accept the proposed standard asset lives of each asset category.

  In particular, we accept the proposed 15 year asset lives for meters and equity raising costs, but accelerated depreciation (3 years) for meter reading devices.[8]

  Consistent with our final decision for standard control services, we specify that forecast, as opposed to actual, depreciation will apply to SA Power Networks' MAB.

- Rate of return

  Our final decision accepts that the same weighted average cost of capital (WACC) and imputation credit (gamma) values for standard control services should apply to alternative control metering services.

  See attachments 3 and 4 for our decision on WACC and gamma values, along with our reasons.

  However, unlike standard control, we will not be annually adjusting SA Power Networks' return on debt.

- Forecast capex

  We substitute SA Power Networks proposed $19.2 million in forecast capex with $19.7 million ($2014–15). Our preliminary decision approves a higher capex than proposed to correct a modelling error in the approved 2015–16 prices for the upfront capital charge.

- Forecast opex

  We accept SA Power Networks' proposed forecast opex of $47.8 million for annual metering charges ($2014–15).

Based on our cost assessment of these individual building blocks, we have rejected the proposed price caps for annual metering services. Our approved price caps which have been updated for our final decision rate of return parameters and the true up between the preliminary and final decision building block forecasts are set out in appendix A.

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[8] SA Power Networks, *Revised regulatory proposal 2015-20: Attachment Q.9 (Public) revised ACS PTRSM,* July 2015, "PTRM input" tab.

16.2.3 Control mechanism

We maintain our preliminary decision 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:

$$p_t^i = p_{t-1}^i(1 + \Delta CPI_t)\left(1 - X_t^i\right) + A_t^i$$

where:

p_{t-1}^i is the cap on the price of service i in year t–1

p_t^i is the cap on the price of service i in year t.

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[9] from the December quarter in year t–2 to the December quarter in year t–1, calculated using the following method:

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–1

divided by

The ABS CPI All Groups, Weighted Average of Eight Capital Cities for the December quarter in regulatory year t–2

minus one.

For example, for the 2016–17 year, t–2 is the December quarter 2014 and t–1 is the December quarter 2015 and in the 2017–18 year, t–2 is the December quarter 2015 and t–1 is the December quarter 2016 and so on.

X_t^i is:

for the annual metering charge (non–capital component), the factor as set out in Table 16.1

for the annual metering charge (capital component), the factor as set out in Table 16.2

for the upfront capital charges, the factor as set out in Table 16.3.

Table 16.1 X factors for annual metering charges: non–capital component (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	-34.81	5.00	5.00	5.00

[9] 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 available of the index alternative index.

Source: AER analysis.

Note: As outlined in section 16.6.4, the X factor has been used to "true-up" the difference between our preliminary and final decisions. Our final decision approves $51.9 ($nominal) in revenue associated with the non–capital component of SA Power Networks' annual metering charges. This is more than the $43.2 million ($nominal) in revenue we accepted at the preliminary decision stage. We have accordingly specified a non–capital X factor in 2016–17 that gives effect to an increase in annual metering prices when used in conjunction with the CPI–X formula. Refer to Table 16.11 in Appendix A for the indicative price changes as result of the above X factors.

Table 16.2 X factors for annual metering charges: capital component (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	–20.47	–15.00	–15.00	–15.00

Source: AER analysis.

Note: As outlined in section 16.6.4, the X factor has been used to "true-up" the difference between our preliminary and final decisions. Our final decision approves $68.5 ($nominal) in revenue associated with the capital component of SA Power Networks' annual metering charges. This is more than the $56.4 million ($nominal) in revenue we accepted at the preliminary decision stage. We have accordingly specified capital X factors that give effect to an increase in annual metering prices when used in conjunction with the CPI–X formula. Refer to Table 16.11 in Appendix A for the indicative price changes as result of the above X factors.

Table 16.3 X factors for upfront capital charge (per cent)

	2016–17	2017–18	2018–19	2019–20
Type 5 meters				
Single element	–17.43	-0.60	-0.75	-0.87
Two element	–17.65	-0.60	-0.75	-0.87
Three phase	–17.39	-0.60	-0.75	-0.87
Type 6 meters				
Single element	–7.64	-0.60	-0.75	-0.87
Two element	–6.57	-0.60	-0.75	-0.87
Three phase	–7.27	-0.60	-0.75	-0.87

Source: AER analysis.

Note: As outlined in section 16.6.4, the X factor has been used to "true-up" the difference between our preliminary and final decisions. The X factors in 2017–18 to 2019–20 are for labour price growth only.

A_i^t is an adjustment factor for residual charges when customers choose to replace assets before the end of their economic life. For metering services, the value of A is zero.

Note—we have a made a typographical adjustment to the formulae, such that time in each parameter is now denoted as a subscript, rather than superscript from the

preliminary decision. This change has no effect on the operation of the formula, and is merely for consistency with the way we have described formulae in other decisions.

16.3 SA Power Networks' revised proposal

We made our preliminary decision in relation to SA Power Networks' initial alternative control metering proposal on 29 April 2015. In its revised proposal, SA Power Networks accepted some aspects of our preliminary decision, but not others.

16.3.1 Structure of metering charges

SA Power Networks' revised proposal accepted the general structure of metering charges in our preliminary decision.[10] This structure comprised of:

- upfront capital charge for all new and upgraded meters installed from 1 July 2015
- annual metering charge comprising two components:
    - capital
    - non-capital
- no exit fee for when a customer 'churns' to a competitive metering service.[11]

Though it accepted the general structure of metering charges in the preliminary decision, SA Power Networks did not accept the cost allocation between the capital and the non–capital components of the annual metering charge. In particular, it did not accept the allocation of its tax liability building block to the non–capital component, on the basis that SA Power Networks considered this to be a fixed cost.[12] It submitted that the recovery of its tax liability should be reallocated to the capital component of the annual metering charge.[13]

16.3.2 Annual metering charge

With regard to the annual metering charge, SA Power Networks' revised proposal:

- generally accepted the pricing structure set out in our preliminary decision[14]
- accepted the charges specified in the preliminary decision for the first year of the 2015–20 regulatory control period (2015–16)[15]
- proposed that any under–recovery in 2015–16 prices as a result of AER 'errors of detail and omissions' are addressed in the approved 2016–17 prices[16]

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10 SA Power Networks, Revised regulatory proposal, July 2015, p. 449.

11 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–7; SA Power Networks, Revised regulatory proposal, July 2015, p. 449.

12 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 432–433.

13 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 433.

14 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 449.

15 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 434.

16 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 434.

- did not accept the charges specified in the preliminary decision for the second year of the 2015–20 regulatory control period and onwards (2016–17 to 2019–20)[17]

The pricing structure which SA Power Networks has generally accepted involves separating out the cost recovery of its revised annual metering charges into capital and non–capital components. Our preliminary decision provided a detailed explanation of how this charging structure would operate.[18] For ease of reference, Appendix B to this attachment provides that information once more. The only aspect of the charging structure SA Power Networks' revised proposal did not accept is the allocation of its tax liability to the non–capital component of the annual metering charge.[19] It proposed that such costs should be allocated to the capital component.[20]

To derive both the capital and non–capital components of its annual metering charges, SA Power Network' revised proposal applied the building block approach. This approach involved forecasting the revenue requirement for each of the metering cost categories and then translating those amounts into price caps. Table 16.4 shows the forecast metering building block requirement in SA Power Networks' revised proposal. Table 16.5 shows the proposed annual charges for metering services that recover the total revised revenue.

Table 16.4 SA Power Networks' proposed metering building block requirement

($ million, nominal)	2015–16	2016–17	2017–18	2018–19	2019–20
Return on capital	6.0	5.8	5.6	5.3	4.9
Return of capital	6.6	7.3	7.9	8.5	8.8
Operating expenditure	10.3	10.4	9.9	10.1	10.2
Tax liability	1.7	1.7	1.7	1.9	1.9
Total unsmoothed revenue	24.5	25.3	25.1	25.8	26.0

Source: SA Power Networks, *Revised regulatory proposal 2015-20, Attachment Q.8: Revised ACS metering pricing model (public)*, July 2015, "Pricing model adjusted for PD" tab.

17 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 434.
18 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, section 16.1.1.1.
19 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 432.
20 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 432.

Table 16.5 SA Power Networks' proposed annual metering service charges

($/year, nominal)		2015–16	2016–17	2017–18	2018–19	2019–20
Annual charge (Type 1-4 'Exceptional' Remotely Read Interval Meter)	Capital	176.18	290.74	296.73	302.84	309.08
	Non–capital	135.07	195.45	199.48	203.59	207.78
Annual charge (Type 5-6 CT Connected Manually Read Meter)	Capital	95.90	158.26	161.52	164.85	168.24
	Non–capital	73.52	106.39	108.58	110.82	113.10
Annual charge (Provision Reading and Data Type 5-6 WC Manually Read Meter)	Capital	11.81	19.33	19.73	20.13	20.55
	Non–capital	8.98	12.99	13.26	13.54	13.81

Source: SA Power Networks, *Revised regulatory proposal 2015-20, Attachment Q.8: Revised ACS metering pricing model (public)*, July 2015, "Revised pricing proposal" tab; AER analysis.

Note: Type 1-4 'Exceptional' Remotely Read Interval Meters are legacy meters for large customers installed prior to 1 July 2000. Type 5-6 WC Manually Read Meters are the meters that have been typically installed for residential customers.

Opex

SA Power Networks' proposed $47.9 million ($2014–15) for metering opex, compared to the AER's preliminary decision of $34.9m ($2014–15).[21]

SA Power Networks accepted, in-principle, our use of the base-step-trend method in assessing metering opex. However, it disagreed with how we applied this approach in our preliminary decision.[22]

Base expenditure

SA Power Networks considered that averaging expenditure over the 2008–09 to 2012–13 to determine the base opex was inappropriate and inaccurate because of data issues from earlier years (accuracy concerns, overheads not allocated and use of estimates).[23]

SA Power Networks also argued that our base adjustment to include type 5 meter maintenance (previously a negotiated distribution service) was too low because it did

[21] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 444.
[22] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 441.
[23] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 441.

not account for the ramping up of Type 5 meter maintenance expenditure over the period and excludes overheads.[24]

To address these issues, SA Power Networks proposed averaging base expenditure from the two most recent years, or alternatively, using 2013–14 as a single base year.[25]

SA Power Networks noted that a positive step change or base adjustment is required to include meter energy data service costs which have been reclassified from standard to alternative control services.[26]

Step changes

SA Power Networks proposed three step changes in its revised proposal:

- increased cost of meeting CT metering installation testing obligations
- impact of metering contestability on meter reading costs
- meter programming software maintenance associated with moving to a new vendor for three-phase Type 6 accumulation meters, in response to our preliminary decision approving a lower unit cost for these meters.

Trend

SA Power Networks proposed different forecast metering customer numbers that reflect how the AER calculated historical metering opex per customer. It also adjusted for the impact of meter churn.[27]

SA Power Networks did not accept our preliminary decision to not include an uplift for input cost escalation. It argues that alternative control metering services are as labour intensive as standard control services and so a consistent weighted labour cost escalation should apply.[28]

16.3.3 Upfront capital charges

With regard to the upfront capital charge, SA Power Networks' revised proposal:

- generally accepted the pricing structure set out in our preliminary decision[29]
- accepted the charges specified in the preliminary decision for the first year of the 2015–20 regulatory control period (2015–16)[30]

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24 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 441.
25 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 441.
26 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 441–442.
27 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 443.
28 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 443.
29 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 449.
30 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 434.

- proposed that any under–recovery in 2015–16 prices as a result of AER 'errors of detail and omissions' are addressed via the inclusion of a non–zero A factor[31]
- did not accept the charges specified in the preliminary decision for the second year of the 2015–20 regulatory control period and onwards (2016–17 to 2019–20).[32]

The pricing structure specified in our preliminary decision provided that the cost of all new and upgraded meters installed from 1 July 2015 will be recovered from customers upfront.[33] SA Power Networks accepted this aspect of our preliminary decision.[34]

In its revised proposal, SA Power Networks accepted our preliminary decision substituting its initially proposed material unit costs for certain types of meters.[35] However, it stated that the cost of moving to a new vendor, in order to achieve the lower meter cost approved by us in the preliminary decision, for those meters, will lead to higher operating costs, which it has made allowance for in its revised proposal.[36] Table 16.6 sets out the proposed upfront metering installation charges in SA Power Networks' revised proposal.

Table 16.6 SA Power Networks proposal – Upfront metering installation charges

($, nominal)	2015–16	2016–17	2017–18	2018–19	2019–20
Type 6					
Single element	111.49	114.91	118.50	122.21	126.03
Two element	280.75	289.37	298.41	307.74	317.35
Three phase	331.33	341.50	352.17	363.17	374.52
Type 5					
Single element, modular - no comms	195.47	201.47	207.77	214.26	220.95
Two element, modular - no comms	280.75	289.37	298.41	307.74	317.35
Three phase, modular - no comms	481.74	496.52	512.04	528.04	544.54

Source: SA Power Networks, *Revised regulatory proposal, Attachment SAPN_Q.8_Public_Revised ACS Metering Pricing Model_Redacted*, "Revised pricing proposal" tab.

31 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 449.
32 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 434.
33 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–7.
34 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 449.
35 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 431.
36 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 431.

16.3.4 Meter transfer and exit fees

Our preliminary decision did not accept SA Power Networks' initial proposal for meter exit fees for when a customer churns to an alternative metering provider. SA Power Networks' revised proposal accepted this aspect of our preliminary decision.[37] But, it submitted that this 'does not prevent it from continuing to charge a meter exit fee for negotiated distribution services (NDS) meters'.[38]

16.3.5 Control mechanism

SA Power Networks' revised proposal did not accept the price control specified in our preliminary decision.[39] This consists of a formula that we will use during the 2015–20 regulatory control period to annually adjust prices for alternative control metering services. Annual adjustments are required to take inflation into account and, if applicable, to apply real cost escalators. The formula specified in our preliminary decision was:[40]

$$p_i^t = p_i^{t-1}(1 + \Delta CPI_t)\left(1 - X_i^t\right) + A_i^t$$

With respect to this formula, our preliminary decision described how the consumer price index (CPI) would be calculated, and set the value of the "X factor" and the "A–factor".[41] It is the values given to the X factor and A–factor in our preliminary decision which SA Power Networks submitted should be amended.

16.3.5.1 X factor

In our preliminary decision we specified different X factors for the upfront capital charge and the annual metering charge.[42] SA Power Networks revised proposal disagreed with this aspect of our decision. It stated that it 'believes the same influences apply to both the installation of meters [upfront capital charge] and the maintenance of reading of meters [annual metering charge]'.[43] SA Power Networks consider that it is appropriate for the same X factors to apply to annual metering charges to reflect the growth in labour costs that have been applied to the upfront meter installation charges.[44]

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37 SA Power Networks, Revised regulatory proposal, July 2015, p. 433.
38 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 433.
39 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 434.
40 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–11 to 16–12.
41 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–12.
42 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–12.
43 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 449.
44 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 430.

16.3.5.2 A–factor

In our preliminary decision we set the A factor to zero.[45] In its revised proposal, SA Power Networks submitted that this should be amended in our final decision. This is on the basis that a 'non–zero A factor would allow the AER to make annual adjustments for any under or over–recovery of [alternative control services] revenue'.[46]

In submitting that the A–factor should be given a non–zero value, SA Power Networks stated that it expects a significant customer 'churn' from its regulated metering service to alternative providers in the contestable market.[47] SA Power Networks submitted that this could lead to an under–recovery in its costs, which it proposed could be addressed through the A–factor, if it is given a non–zero value.[48]

SA Power Networks' revised proposal also stated that it considered the AER to have made arithmetic errors in the modelling of its prices for the preliminary decision. It stated that these errors should be addressed via the A factor, provided its value was not set to zero in the final decision.[49]

16.4 Assessment approach

In our preliminary decision we first considered SA Power Networks' proposed structure of metering services. We then considered SA Power Networks' proposed costs, tailoring our assessment approach according to each type of charge.

We have followed the same assessment approach in our final decision. Since SA Power Networks has generally accepted the structure of metering services specified in our preliminary decision, our assessment of the distributor's revised proposal focused on its revised costs.

16.4.1 Structure of metering charges

SA Power Networks' revised proposal accepted the general structure of metering charges specified in our preliminary decision. Notwithstanding, it proposed changes to the allocation of some costs within this general structure.[50] In assessing this proposal, as well as the structure of metering charges overall, we were guided by:

- the AEMC's draft rule change into metering contestability
- the service classification and control mechanism factors in the NER.[51]

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45 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–12.
46 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 430.
47 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 430.
48 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 430.
49 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 430.
50 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 432.
51 NER, cl. 6.2.2(c) and cl. 6.2.5(d).

In relation to the structure of metering services, the AEMC's draft rule 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'.[52] Importantly, the way in which the AER achieves this outcome is not specified.

With regard to the service classification and control mechanism factors, they require us to consider whether it is more appropriate to allocate metering services costs through annual charges, upfront fees or network charges recovered from all customers. Table 16.7 sets out the factors which we have considered.

Table 16.7 Classification and control mechanism factors

Classification factors	Control mechanism factors
Potential for development of competition in the relevant market and how the classification might influence that potential	Potential for development of competition in the relevant market and how the control mechanism might influence that potential
The possible effects of classification on administrative costs of the AER, the distribution business and users or potential users	The possible effects of the control mechanism on administrative costs of the AER, the distribution business and users or potential users
The regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made	The regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made
The desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction)	The desirability of a consistent regulatory arrangements to similar services (both within and beyond the relevant jurisdiction)
The extent of the costs of providing the relevant service are directly attributable to the person to which the service is provided	Any other relevant factor
Any other relevant factor	

Source: NER, cl. 6.2.2(c) and cl. 6.2.5(d).

16.4.2 Annual metering service charges

To develop its proposed price caps for annual metering services, SA Power Networks' revised proposal applied the building block approach. We considered this to be a good forecasting approach. Our assessment focused on the value of each building block in SA Power Networks' revised proposal.

Opening metering asset base

In assessing the proposed opening MAB value, we reviewed how SA Power Networks had separated its proposed opening value as at 1 July 2015 from the RAB for standard control services. This is consistent with our preliminary decision.

[52] AEMC, *Draft rule determination: Expanding competition in metering and related services,* 26 March 2015, p. 225.

Depreciation

With respect to depreciation, we maintained our preliminary decision approach and considered the remaining asset lives SA Power Networks proposed and had regard to the opening of competition to metering services.

Forecast capex

Most of SA Power Networks' revised capex forecast for annual metering services comprises of the cost of replacing meters.[53] To assess this aspect of SA Power Networks' forecast capex, we applied the same approach used in our preliminary decision. This required us to consider the revised:

- 'material' and 'non–material' unit costs[54]
- volume of ‘reactive’ and ‘proactive’ replacements.

In addition to replacements, SA Power Networks' revised proposal included forecast capex for IT Systems and Infrastructure. In assessing these costs we considered the forecast capex that is reasonably required for SA Power Networks to recover its efficient costs.

Forecast opex

We applied a base-step-trend approach to assessing SA Power Networks' proposed opex.

Base

As opex is largely recurrent in nature, we considered SA Power Networks' 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 preference is to use a five year average to establish the base, 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

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[53] In its initial proposal SA Power Networks forecast capex included the cost of new or upgraded connections and replacements. The revised proposal submitted by SA Power Networks, however, only proposes to recover the cost of replacements through the annual metering charge. This is consistent with our preliminary decision that the cost of new or upgraded connections should be recovered upfront from customers at the time of installation.

[54] Material costs relate to the hardware used to provide metering services. Non–material costs relate to the labour activities which SA Power Networks must perform in order to replace a meter.

data provided by the distributors was prepared according to a consistent set of instructions and definitions.[55]

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 therefore made adjustments by either adding/removing historic expenditure such that our analysis was based on historic metering opex for default metering services only.

With this adjusted base data, we then performed our benchmarking analysis. We used a partial performance indicator for our benchmarking analysis. This compared historic annual metering opex per customer across non-Victorian distributors in the national electricity market.[56]

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

Step changes

We considered whether we should apply any step changes. These are adjustments which increase or decrease a distribution business' efficient expenditure.[57]

As outlined in our Expenditure forecast assessment guideline, our approach to step changes is that we will only accept them if they are associated with a new regulatory obligation or a capex/opex trade off.[58]

For step changes arising from new regulatory obligations, we will assess (among other things):

- whether there is a binding (that is, uncontrollable) change in regulatory obligations that affects their efficient forecast expenditure

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55 AER, Economic benchmarking RIN for distribution network service providers - Instructions and Definitions - Sample, November 2013.

56 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.

57 AER, *Expenditure assessment forecast guideline*, November 2013, p. 9.

58 AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

- when this change event occurs and when it is efficient to incur expenditure to comply with the changed obligation
- what options were considered to meet the change in regulatory obligations
- whether the option selected was an efficient option—that is, whether the distribution business took appropriate steps to minimise its expected cost of compliance from the time there was sufficient certainty that the obligation would become binding.[59]

For capex/opex trade-off step changes, we will assess whether it is prudent and efficient to substitute capex for opex or vice versa.[60]

Trend

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

16.4.3 Upfront capital charge

To assess the reasonableness of the proposed charges, we analysed SA Power Networks' unit costs. We did not consider the forecast volumes of new or upgraded connections since they have no bearing on the value of an upfront charge. This is the same approach applied in our preliminary decision.

16.4.4 Metering exit fees

SA Power Networks accepted our preliminary decision to remove metering exit fees for when a customer leaves it's regulated metering services.[61] We have therefore not assessed whether an exit fee should apply as part of our final decision.

16.4.5 Control mechanism

SA Power Networks accepted preliminary decision on the control mechanism formula and so we have not reviewed it further. However, we have assessed the particular X factor and A–factor values that should be included in the control mechanism.

16.5 Interrelationships

We apply the same rate of return parameters for all direct control services (standard and alternative control services).

Our final decision on SA Power Networks' alternative control metering proposal therefore interrelates with our final decision on rate of return and imputation credits.

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59 AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

60 AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

61 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 433.

Please refer to attachments 3 and 4 for the WACC and gamma values we accept for direct control services, along with our reasons.

16.6 Reasons for final decision

16.6.1 Structure of metering charges

We maintain the same general structure of metering charges specified in our preliminary decision. Though we maintain this aspect of our preliminary decision, we accept SA Power Networks' proposal regarding how its tax costs are recovered. This is a change in cost allocation between the capital and non–capital components of the annual metering charge; it does not affect the general structure of metering charges.

General structure

The general structure of metering charges which we have maintained from our preliminary decision is more fully explained in Appendix B. In summary, it consists of two types of charges:

1. upfront capital charge for all new and upgraded meters from 1 July 2015
2. annual metering charge comprising of capital and non–capital components.

This general structure was accepted by SA Power Networks in its revised proposal.[62] The South Australia Council of Social Services also endorsed our preliminary decision with respect to price caps for new and upgraded connections.[63] Vector supported our approach too. In particular, Vector agreed with our preliminary decision to remove exit fees and the method by which we would 'allow distributors… to recover the “residual capital cost” of their efficient regulated investment'.[64] As well, the SA Government supported our preliminary decision regarding SA Power Networks 'tariffs ahead of pending regulatory changes relating to the competitive framework for advanced metering'.[65]

We received submissions from Origin Energy and the Energy Retailers Association of Australia (ERAA) which did not support our preliminary decision. In deciding whether we should maintain our preliminary decision, we considered those submissions.

With respect to Origin's submission, it stated that the structure set out in our preliminary decision 'effectively imposes an exit fee to those customers who migrate to a "smart meter"'.[66] It considered this to be the case because 'a customer taking a smart

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62 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 449.

63 SACOSS, Submission on AER preliminary decision for SA Power Networks, 1 July 2015, p. 4.

64 Vector, *Submission on AER preliminary decision for SA Power Networks*, 3 July 2015, p. 1.

65 SA Government, *Submission on AER preliminary decision for SA Power Networks*, 10 July 2015, p. 3.

66 Origin Energy, Submission on AER preliminary decision for SA Power Networks, 3 July 2015, p. 11.

meter will bear the cost of legacy metering investments for the remaining life of the asset base rather than as a lump sum'.[67]

Origin Energy is correct in submitting that when customers transition to alternative metering providers they will continue paying the capital component of their annual metering charge (see appendix B). However, Origin Energy appears to be unsupportive of this on the basis that it considered that customers should not pay any costs relating to a legacy meter after they have 'churned'. Such an approach, however, would not comply with the regulatory framework we administer as SA Power Networks must be given a reasonable opportunity to recover the costs of its past investments.[68] To understand why this is the case, the manner in which SA Power Networks recovers its legacy metering costs needs to be considered.

As shown in appendix B, prior to 1 July 2015 the capital costs SA Power Networks has incurred in relation to metering have been amortised. That is, the network service provider has incurred its capital cost for metering services upfront, which have then been added to an asset base and recovered gradually through annual charges over time. Origin Energy's submission appears to advocate for a charging structure whereby SA Power Networks would be required to 'write–off' unrecovered costs it has incurred upfront, whenever a customer churns. Such an arrangement is not consistent with the regulatory framework established under the National Electricity Law (NEL) and we have not considered such an approach. In particular the NEL requires us to provide SA Power Networks with a reasonable opportunity to recover at least its efficient costs.[69] This is inclusive of the capital costs SA Power Networks has incurred for metering services upfront and which it is yet to fully recover.

Additionally, Origin Energy stated, as did the ERAA, that the AER should give more consideration to the long term implications of the structure of metering charges we accept.[70] Our view is that we gave such consideration in our preliminary decision. This is seen with respect to the levying of upfront charges for new and upfront meters and the establishment of a 'two part' tariff for annual metering services.

Broadly, we consider the upfront charge for all new and upgraded meter addresses the long term implication of stakeholders by taking into account the expansion of competition in metering.[71] This is on the basis that it should help level the competitive playing field for new meters by providing transparent standalone prices for all new or upgraded meter connections. It will also shift how SA Power Networks' capital costs are recovered. This is from the annual metering services charge, where costs are spread across all customers, to an upfront payment which new entrants to the market are able to compete with in terms of price. These reasons for charging for new and

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67 Origin Energy, Submission on AER preliminary decision for SA Power Networks, 3 July 2015, p. 11.

68 NEL, s. 7A(2).

69 NEL, s. 7A.

70 Origin Energy, Submission on AER preliminary decision for SA Power Networks, 3 July 2015, p. 11; ERAA, Submission on ART preliminary decision for SA Power Networks, 3 July 2015, pp. 1–2.

71 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–23.

upgraded connections upfront were outlined in our preliminary decision.[72] We consider them to still be applicable.

With regard to the annual metering charge, our decision to implement a two–part tariff structure shows that we have considered the interests of different stakeholders and the long–term implications for them. As noted by SA Power Networks, our reason for accepting a two–part tariff is 'to keep [distribution network service providers] financially "whole" through the transition to expanded metering contestability'.[73] At the same time, it avoids a situation where customers would be charged a lump sum exit fee to recover any remaining residual costs when they churn to an alternative metering provider. This could have acted as a barrier to participants seeking to enter the market following the expansion of metering contestability.

In general, we are satisfied that our decision balances the interests of different stakeholders and gives effect to a regulatory regime robust enough to transition to metering contestability.

Allocation of costs

Our final decision maintains the general structure of metering charges in our preliminary decision. However, we have accepted SA Power Networks' proposal for a reallocation of costs between the capital and non–capital components of the annual metering charge.

More specifically, our preliminary decision included the cost recovery of SA Power Networks' tax liability in the non–capital component.[74] Our final decision, however, gives effect to SA Power Networks' proposal to include these costs in the capital component. We accept SA Power Networks' observation that its 'tax liability is interminably linked to the return on capital and relevant depreciation'[75] and so should be allocated to the capital component of the annual metering charge.

16.6.2 Annual metering services

Our final decision accepts many of SA Power Networks' total proposed building blocks for annual metering services. We also approve an additional amount of capex, which SA Power Networks did not include in its revised proposal. This was to correct an error made at the preliminary decision stage.

Opening metering asset base

We approve SA Power Networks' proposed opening MAB value as at 1 July 2015 of $84.8 million ($nominal). In accepting SA Power Networks' proposed opening MAB we

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72 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, .p 16–23.

73 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 432.

74 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p 16–7.

75 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 433.

found that the proposed asset value complied with all regulatory requirements.[76] In particular, the calculated amount was consistent with changes made to the roll forward model for standard control services. For more information about those changes, see attachment 2 to this final decision.

Depreciation

We maintain our preliminary decision accepting SA Power Networks' depreciation method of the MAB. This involved using the AER's post tax revenue model which contains a specific depreciation calculation method. We also confirm that forecast, as opposed to actual, depreciation will apply to the roll forward of SA Power Networks' MAB at the next regulatory control period.

With respect to asset lives, we accept SA Power Networks' proposal for meters and equity raising costs to be depreciated over 15 years. We consider 15 years to be efficient because it coincides with the average technical life of SA Power Networks' meters. The result is that the cost recovery of the assets will match the length of their expected usefulness to customers.

SA Power Networks proposed accelerated depreciation for meter reading devices.[77] We accept this proposal because the proposed standard life of the devices (three years) corresponds with their technical working life. We consider this to be efficient because customers will pay for the assets over the period in which they are being used to provide services.

Forecast capex

Our final decision is to substitute SA Power Networks' revised capex forecast of $19.2 million for annual metering services, with $19.7 million ($2014–15). Our final decision accepts each aspect of the revised capex proposal from SA Power Networks plus an additional $0.5 million ($2014–15) to correct an error in the modelling of the AER's preliminary decision prices for the "upfront capital charge".

Table 16.8 sets out SA Power Networks' initial and revised capex forecast along with our preliminary and final decisions. Our final decision is an increase on the $10.6 million we approved at the preliminary determination stage[78] and about 46 percent of the $42.7 million that SA Power Networks forecast in its initial proposal ($2014–15).[79]

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[76] NER, cl. S6.1.3(7).

[77] SA Power Networks, *Revised regulatory proposal 2015-20: Attachment Q.9 (Public) revised ACS PTRSM,* July 2015, "PTRM input" tab.

[78] AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–10.

[79] SA Power Networks, *Initial regulatory proposal: 2015–20: Attachment 29 – SAPN ACS metering tariff development methodology*, November 2014, p. 6.

Table 16.8 SA Power Networks' capex proposals and AER decisions ($million 2014–15)

	Initial proposal	Preliminary decision	Revised proposal	Final decision
New connections	12.4	0.0	0.0	0.5
Reactive replacement	1.6	0.8	5.2	5.2
Proactive replacement	26.4	9.8	12.3	12.3
IT Systems and Infrastructure	2.4	0.0	1.7	1.7
Total	42.7	10.6	19.2	19.7

Source: AER analysis; SA Power Networks, *Revised regulatory proposal: 2015–20: Attachment Q.3 – SAPN revised ACS capex forecast, "Output to SEM" tab*; AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–29.

New connections

We accept $0.5 million in new connection capex for the annual metering charge ($2014–15). Our final decision approves this amount to correct a clerical error made in relation to the modelling of SA Power Networks' upfront capital charges.

In our preliminary decision on SA Power Networks' annual metering charge, we did not accept any capex associated with new connections. Our reasoning, which SA Power Networks accepted in its revised proposal, was that the cost of new connections should be recovered via an upfront capital charge paid directly by customers at the time of installation.[80]

We nonetheless accept that in modelling SA Power Networks upfront capital charges in our preliminary decision, we made an error. As pointed out by SA Power Networks' revised proposal, this error related to a 'slip' whereby we did not apply on-cost and overhead adjustments to the approved upfront capital charges for type 5 meter installations.[81] We accept that this error will lead to an under–recovery in SA Power Networks' costs in the 2015–16 placeholder year.

To correct for this, we have decided not to adjust the upfront capital charge. Instead, we have determined that SA Power Networks' capital allowance for the annual metering charge should be adjusted. This is so the cost of remediating the error can be recovered across all customers who receive annual metering services from SA Power Networks. Because the upfront capital charge is a "one–off" payment, this would not happen if the adjustment was made to it.

[80] AER, *Preliminary decision on SA Power Networks 2015–19*, April 2015, p. 16–36.

[81] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 449

Taking this approach, our final decision regarding SA Power Networks' annual metering charge is to approve $0.5 million in capex for new connections ($2014–15). Based on a forecast provided by SA Power Networks', we consider this to be a reasonable estimate of the likely under–recovery that it will experience. The approved additional capex will put SA Power Networks in the position it would have been in had the error not occurred.

Replacements

We approve SA Power Networks' revised replacement capex forecast of $17.5 million ($2014–15). This capex forecast comprises of $5.2 million in 'reactive' meter replacements and $12.3 million in 'proactive' meter replacements ($2014-15).

For both reactive and proactive replacements, we considered two inputs. These are the forecast 'unit costs' and 'volume of replacements'. To build up its revised forecast, SA Power Networks multiplied these inputs by their respective values. Hence an adjustment to either would lead to us substituting the proposed capex forecast with an alternative.

Unit costs

We accept SA Power Networks' revised unit costs. SA Power Networks accepted the alternative lower unit costs in our preliminary decision.

Our preliminary decision accepted all of SA Power Networks' initially proposed 'non–material' unit costs. These costs relate to the labour associated with the installation of a replaced meter. We did not, however, accept all of SA Power Networks 'material' unit costs. Such costs refer to the price of the actual metering device.

In response, SA Power Networks has revised the material unit costs which we did not accept. We are satisfied that these revised amounts are reasonable. They are equal to the substitute unit costs in our preliminary decision. These were based on advice from our consultant Marsden Jacob Associates (Marsden Jacob). We are satisfied with SA Power Networks revised unit costs and we have accepted these in our final decision.

SA Power Networks has proposed a small amount of additional costs associated with moving to a new supplier of three–phase Type 6 meters, which we concluded in our preliminary decision were above observed market rates.[82] Our view is that incurring such additional costs is prudent and efficient if the move will lead to net savings. We reviewed how much SA Power Networks would save from moving to an alternative supplier to acquire the lower cost meter we substituted in the preliminary decision and compared that amount against the proposed capex (and opex) it would incur in changing suppliers. Since we found that there would be a net saving, the additional costs have been approved.

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[82] SA Power Networks, *Regulatory proposal 2015-20,* November 2014, p. 331.

The accepted unit costs are subject to a confidentiality claim. In this instance, we are not satisfied that the public benefit in having the unit costs disclosed outweighs the potential detriment SA Power Networks or any of its suppliers may incur.

Volume of replacements

We accept SA Power Networks' revised volume of 'reactive' and 'proactive' replacements. The revised forecasts satisfactorily address aspects of SA Power Networks' initial proposal which we did not accept in our preliminary decision.

Table 16.9 sets out SA Power Networks' initial and revised forecast volumes of replacements along with our preliminary and final decisions. It shows that the revised forecast for reactive replacements is more than we approved in our preliminary decision. This is by a margin of 15 715 meters. The revised forecast of proactive replacements is also more than we previously accepted. However, this is only by an additional 51 meters.

Table 16.9 Forecast and approved volumes of meter replacements

	Initial forecast	Preliminary decision	Revised forecast	Final decision
Reactive replacements	10 324	10 324	26 039	26 039
Proactive replacements	108 301	61 480	61 531	61 531

Source: SA Power Networks, *Revised regulatory proposal: SAPN Q.3 PUBLIC Capex forecast*, "Volumes" tab.

The revised forecast of reactive replacements is above SA Power Networks historical levels. In our preliminary decision, we stated that reactive replacements are made in response to full functionality failure, such as physical damage, and are usually detected at a meter reading or other site visit.[83] We further stated that we consider such functionality failures to be statistically random in nature and consider that historical performance is a good indicator of future requirements.[84] On that basis, it would appear we should not accept SA Power Networks' revised forecast of reactive replacements because it exceeds historical requirements.

We have nonetheless decided to accept SA Power Networks' revised forecast for reactive replacements. In reaching this conclusion, we referred to businesses cases supporting the additional 15 715 meters included in SA Power Networks' reactive replacement forecast.[85] These business cases indicate that SA Power Networks may be experiencing catastrophic failure of some meters at a level greater than historically recorded.[86]

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[83] AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–37.

[84] AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–37.

[85] SA Power Networks, *AER SAPN 022*, 5 March 2015.

[86] SA Power Networks, *AER SAPN 022*, 5 March 2015.

Additionally, we took into account our preliminary decision to substitute SA Power Networks' proactive replacement forecast with a substantially lower forecast than initially proposed. Our reasoning for making this substitute, which has largely been accepted in the revised proposal, was based on the limited data SA Power Networks was able to provide.[87] Given this limited data, we determined that a historical volume of proactive replacements was the best forecast we could accept. This was despite historical levels of proactive replacements not necessarily being a good indicator of future performance. With this in mind, we have determined that it is appropriate to take a conservative approach in relation to SA Power Networks' revised reactive replacements and accept the proposal in full.

With regard to SA Power Networks' revised forecast of proactive replacements, the additional number of proposed meters is not substantial, totalling 51. Likewise the total additional capex is small ($44,000).[88] SA Power Networks has also stated that the meters in question, which are situated at the Holdfast Shores' residential complex, use obsolete technology for which there are no spare parts.[89] As a consequence, SA Power Networks stated that it prudent to replace half the meters in the 2015–20 regulatory control period.[90] It could then retain the equipment in the replaced meters to use as spare parts for failures that may occur with the other half. We consider this to be a prudent approach.

Our final decision is to accept the total number of reactive and proactive replacements, as set out in Table 16.9 above.

IT Systems and Infrastructure

Our final decision is to approve SA Power Networks' revised capex of $1.7 million for IT Systems and Infrastructure ($2014–15). The approved amount is made up of $1.3 million for hand held meter reading devices and $0.4 million for the facilitation of new meter billing arrangements ($2014–15).[91]

In our preliminary decision, we did not accept any capex associated with IT Systems and Infrastructure.[92] According to SA Power Networks' initial proposal, it appeared that all of the proposed costs were associated with the smart–ready meter program. We did not accept any expenditure for that program in our preliminary decision so it followed that we would not approve the proposed IT Systems and Infrastructure capex.

SA Power Networks' revised proposal has, however, clarified that not all of its initially proposed IT System and Infrastructure capex related to the smart–ready meter program. It stated that some of the proposed capex ($1.3 million) was for the

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87 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–38.
88 SA Power Networks, *Revised regulatory proposal,* July 2015, p. 337.
89 SA Power Networks, *Revised regulatory proposal,* July 2015, p. 337.
90 SA Power Networks, *Revised regulatory proposal,* July 2015, p. 337.
91 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 437.
92 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–29.

replacement of hand–held meter reading devices.[93] After considering SA Power Networks' historical costs relating to such devices, we are satisfied that the revised forecast is 'business as usual' capex. On that basis, our final decision is to accept the full amount.

We also accept the revised capex proposal for $0.4 million ($2014–15) for the facilitation of new metering billing arrangements. Such costs are likely to be required as consequence of the structure of metering charges that apply to SA Power Networks, and which it has accepted (see appendix B).

Forecast opex

We accept SA Power Networks' proposed forecast opex of $47.8 million ($2014–15) as it is within the range of our alternative forecasts.

In the following section we explain how we arrived at our alternative forecasts by using the base-step-trend approach.

Base

As opex is largely recurrent, we use historical opex as the starting point for establishing an efficient base level of opex.

SA Power Networks considered our preliminary decision to use a five year average base period from 2008–09 to 2012–13 was inappropriate for the following reasons:[94]

- the accuracy of records and necessary cost allocations associated with estimated historical expenditure is low in the earliest years of the base period selected;
- in 2010/11, the first year that metering services was classified as ACS, no overheads were allocated to ACS, understating ACS costs in that year;
- the estimated expenditure prior to 2009/10 had to be re-cast using the current CAM; and
- the most recent and accurate data provided to the AER is for the 2013/14 year, and this year is not included in the AER's calculations.

As a regulated business, SA Power Networks is responsible for keeping and providing accurate records of its expenditure. It is reasonable for us to rely the audited data that SA Power Networks has provided for our analysis. Nonetheless, we have taken into account SA Power Networks' concerns by testing our alternative forecasts using both a five year average base and a 2013–14 base to ensure the robustness of our analysis.

With regard to the latter two points, our final decision updated the five year average to be from 2009–20 to 2013–14 so those concerns have been addressed.

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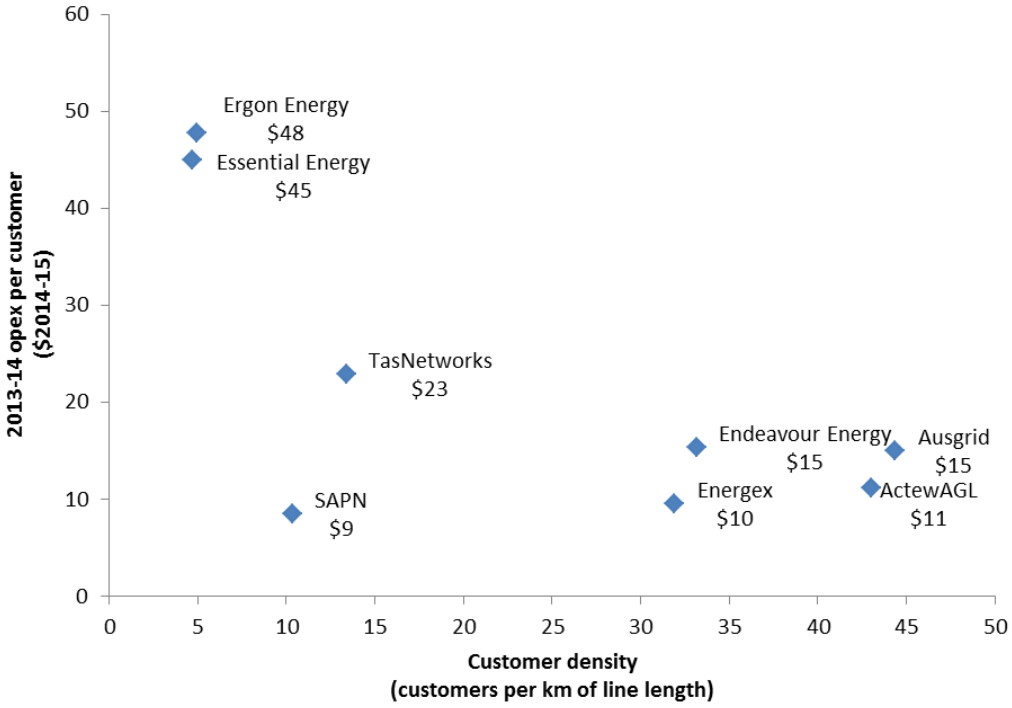
93 SA Power Networks, *Revised regulatory proposal,* July 2015, p. 337.

94 SA Power Networks, *Revised regulatory proposal,* July 2015, p. 441.

We accepted SA Power Networks' revised base adjustment amount to include overheads for Type 5 maintenance costs.

For our final decision, we updated our benchmarking analysis to include 2013–14 data.

Figure 16.1 Metering opex per customer in 2013–14 ($ 2014–15)



As SA Power Networks has a lower opex per customer spend than the other non-Victorian distributors, we maintain our preliminary decision to not apply an efficiency adjustment to SA Power Networks' base metering opex.

Step

SA Power Networks' proposed four step changes

1. Reclassification of relevant meter data services

   SA Power Networks noted that a positive step change or base adjustment is required to include meter energy data service costs which have been reclassified from standard to alternative control services.[95]

   SA Power Networks did not provide historical meter data service costs. Instead it provided a forecast for 2014–15 which falls outside of our base period. We have therefore allowed this adjustment for SA Power Networks through a step change rather than a base adjustment. This amounts to an increase of $2.2 million per annum.

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[95] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 441–442.

2. Increased cost in CT metering compliance obligations

   We do not accept this step change.

   Firstly, because it relates to an existing regulatory obligation. We acknowledge that some types of projects and programs of expenditure a service provider undertakes will differ between years and between regulatory control periods. However, we do not consider variation in the expenditure on projects and programs is a reason to increase the revenue it can recover from metering customers.

   We make our assessment on the total forecast metering opex and not on particular categories or projects in the metering opex forecast. Within total metering opex we would expect to see some variation in the composition of expenditure from year to year. That is, expenditure for some categories will be higher than usual in any given year while other categories will be lower than usual. However, these variations tend to offset each other so that total opex is relatively stable.

   Secondly, a step change should not double count the costs of increased volume or scale compensated through the forecast change in output. We account for output growth by applying a forecast output growth factor to the opex base year. If the output growth measure used captures changes in output then step changes that relate to forecast changes in output will not be required.

   Given that CT metering installation compliance is an existing regulatory obligation and because we already account for output growth when trending forward the base, we do not accept this step change.

3. Impact of metering contestability on meter reading costs

   We do not accept this step change as the uncertainty of churn rates makes it difficult to forecast the cost impact.

   We consider that a cost pass event would be a more appropriate mechanism for addressing any under or over recovery in costs associated with an expansion of metering contestability. Any cost pass through should consider the net cost impact.

   For example, we have allowed forecast replacement capex for the entire period even though it is likely that distributors will not be allowed to install meters on a replacement basis once contestability commences. It may be the case that an increase in meter reading costs may be offset by savings in not having to install replacement meters in later years.

4. Meter programming software maintenance

   We accept this step change as it relates to our approved additional capex to allow SA Power Networks to transition to a lower cost provider for its three phase Type 6 accumulation meters.

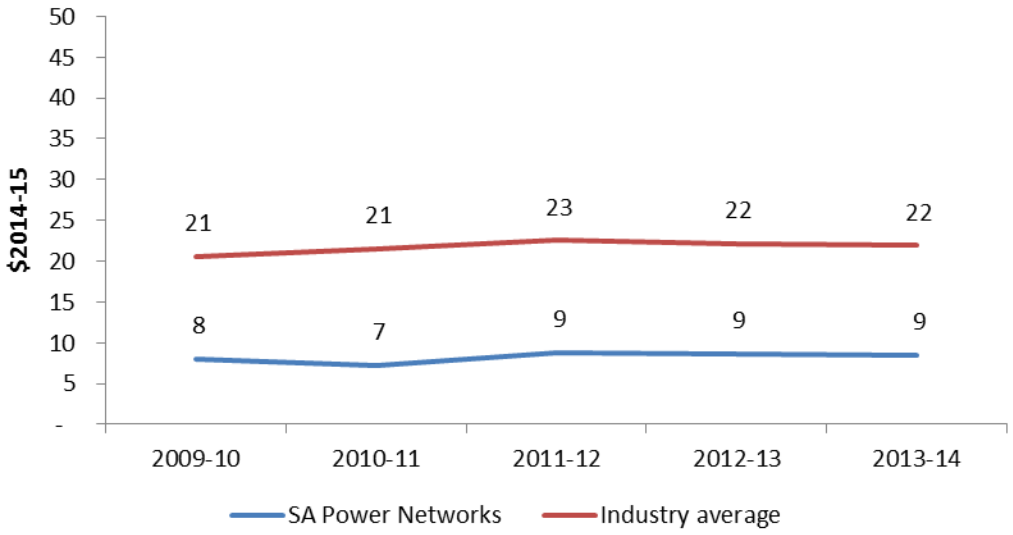
Trend

We trend forward the base using forecast customer numbers. SA Power Networks proposed alternative customer numbers that were consistent with the approach we used to calculated historical metering opex, adjusted for the impact of meter churn.[96] However, we do not think it necessary to account for meter churn in setting forecast opex. This is because under the price cap, the revenue recovered is self-adjusting for actual customer numbers. That is, if a customer switches to a competitive metering provider, they will stop paying the non-capital component of the annual metering charge.

We considered how to account for changes in productivity and real price growth. SA Power Networks did not accept our preliminary decision approach to not apply any rate of change uplift to cater for escalation of input costs and have proposed to apply a weighted labour cost escalator factor, consistent with the approach used in standard control services.[97]

We would allow for uplift if there was a reason that led us to forecast real increases to metering opex per customer spend in the 2015–20 regulatory control period. While it may be the case that metering services is as equally labour intensive as standard control services,[98] it does not alter the fact that metering opex spend has been stable over the 2009–10 to 2013–14 period. This trend could either be because metering specific prices have not been increasing in real terms or that SA Power Networks has been able to offset real price increases through productivity improvements.

Figure 16.2 Base metering opex per customer (2009–10 to 2013–14)



[96] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 443.
[97] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 443.
[98] SA Power Networks, *Revised Regulatory Proposal 2015–20*, July 2015, p. 443.

Given that opex is largely recurrent and metering opex per customer did not increase over the 2009–10 to 2013–14 period, we have no basis to forecast metering opex per customer to increase in the 2015–20 regulatory control period. Therefore, we maintain our preliminary decision to apply zero forecast real price and productivity growth.[99]

Our alternative forecasts are $46.9 million when using a five year average base and $48.1 million when using a single 2013–14 base year ($2014–15). This is a relatively small difference which demonstrates that the choice of base period does not materially alter our forecast.

We accept SA Power Networks' proposed forecast opex of $47.8 million ($2014–15) as it is within the range of our alternative forecasts.

16.6.3 Upfront capital charge

We accept SA Power Networks' adoption of our preliminary decision that the cost of new or upgraded meters is recovered via an upfront capital charge. We also approve the upfront charges in SA Power Networks' revised proposal.

For the upfront capital charge, our preliminary decision accepted all but one of SA Power Networks' initially proposed price caps. The price cap which we did not accept was for the installation of a new or upgraded three phase type 6 accumulation meter. Our reasoning was SA Power Networks' proposed unit cost for that particular meter was outside the range which we considered to be reasonable, based on advice from our consultant.[100]

In its revised proposal, SA Power Networks' used a lower unit cost for its three phase type 6 accumulation meter. The low unit cost is within the range which we consider to be reasonable and hence our final decision is to approve the price cap.

SA Power Networks' revised upfront capital charges also updated for on–costs and business overhead costs.[101] We assessed that these updates were in accordance with its approved cost allocation methodology and, therefore, they have been accepted.

The upfront capital charges which this final decision approves are set out in Appendix A. This also sets out the X factor values which we will apply each year when SA Power Networks submits it annual pricing proposal. These X factors adjust for labour cost changes in South Australia.[102] The 2016–17 X factor also adjusts for the price difference between our preliminary and final decisions regarding the upfront capital charge.

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99 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–44.

100 AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p. 16–45.

101 SA Power Networks, Revised regulatory proposal, July 2015, p. 448.

102 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,

16.6.4 Control mechanism

We maintain our preliminary decision on the X factors to apply during the 2015–20 regulatory control period. This accepts X factor values for the annual metering charge that are for smoothing purposes only (no real price escalation), but X factors for the upfront capital charge that do allow for real labour price escalation.

We took SA Power Networks' revised proposal into account, but nonetheless decided to conduct our assessment of the X factors applicable to the annual metering charge and the upfront charge separately. In conducting this separate assessment, we have determined that different X factors should apply. This is because of differences in how the annual metering charge and upfront capital charge have been forecast.

True up

We confirm that a true–up will apply to both annual metering services and the upfront capital charge. This true–up will operate through the X factor and requires no amendment to the control mechanism formula specified in our preliminary decision, and approved in this final decision (see section 16.2.3). More specifically, to give effect to the difference between our preliminary and final decisions we have:

- adjusted the X factor in 2016–17
- used the remaining three years of the regulatory control period, to smooth the adjustment.

By doing this, SA Power Networks will be given an opportunity to recover its efficient alternative control metering costs.

X factor – annual metering charge

Escalation

We maintain our preliminary decision that the X factor for the annual metering charge should be for smoothing prices only.

For the annual metering charge, a building block approach has been applied which uses a "top down" approach in relation to forecasting SA Power Networks' opex requirement. This approach takes real price growth into account when trending forward the base metering opex, plus or minus any step changes. Because of this, there is a strong methodological reason to not allow for real price escalation through setting the X factor values for annual metering charges. This is because the effect of any real price growth has already been considered in the cost build–up.

This is consistent with our approach for standard control services where real price escalation is assessed through our building block analysis and where X factors are used for smoothing purposes only.

Even if we did accept that real price escalation should be included in our assessment of X factor values for the annual metering charge, we would still set it at zero.

In reaching this conclusion, we have considered the inputs making up SA Power Networks' annual metering charge. These inputs consist of both materials and labour. With respect to them, we consider:

- annual changes in the price of materials to typically move with CPI
- annual changes in the price of labour may move at a rate less or greater than CPI, but any movements of this kind are either not significant or manageable.

Our view that the cost of materials typically moves at an annual rate equal or similar to CPI is a general observation the AER has made over the course of multiple regulatory determinations. Therefore, there is no basis to forecast real materials price escalation. With respect to labour prices, we accept that this is an input into the annual metering charge which may move at an annual rate that is less or greater than CPI.

However, as we explained in the 'trend' section of our opex analysis in section 16.6.2 of this attachment, we have observed that SA Power Networks' base metering opex per customer from 2009–10 to 2013–14 has not experienced any real price growth. We consider this to be significant because the majority of SA Power Networks' metering opex is made up of labour inputs.

We consider that the flat rate of real price growth in SA Power Networks' metering opex shows that an annual adjustment above or below CPI is not required. This is because either metering specific prices are not increasing or that SA Power Networks have been able to offset this through productivity improvements. As there have been no actual real price increases related to metering expenditure in the past, there is no rationale to forecast real price increases in the next regulatory control period.

Accordingly, we maintain our preliminary decision that the X factor for the annual metering charge should be only adjusted to smooth prices across the 2015–20 regulatory control period.

Components

We have applied an aspect of Energex's revised regulatory proposal for the 2015–20 regulatory control to SA Power Networks. This relates to Energex's submission that there should be separate X factors for its capital and non–capital components of the annual metering charge.[103]

In support of its proposal, Energex noted that the number of customers paying the capital and non–capital component of its annual metering charge will vary during the 2015–20 regulatory control period. In particular, it stated that the introduction of the upfront capital charges (see section 16.2.1) means that there will be no new type 6 metering capital customers for Energex (or SA Power Networks) after 30 June 2015. By contrast, Energex considered customers paying the non–capital component will continue to increase, thus creating a discrepancy.

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[103] Energex, *Revised regulatory proposal*, July 2015, p. 140.

We accept Energex's observations regarding the effect of the upfront capital charge on the number of customers which will pay the capital component of the annual metering charge. We have therefore given effect to this outcome for Energex by specifying separate X factors for the capital and non–capital components. Since SA Power Networks is in the same circumstances with respect to its charging structure, we have applied the same approach to it. Refer to section 16.2.3 above where we set out the approved X factors.

X factor — upfront charge

In our preliminary decision, we accepted negative X factors for the upfront capital charge.[104] We maintain this aspect of our preliminary decision.

In contrast to the top down approach used for annual metering charges, we have applied a "bottom–up" approach to forecasting SA Power Networks' upfront capital charge. It does not incorporate an assessment of real price growth. Accordingly, when considering the X factor that should apply to the upfront capital charge, more scope is available to take real price growth into account.

To determine the value that should be given to the X factors for the upfront capital charge, we observed that the inputs into the upfront capital charge consist of approximately 40 percent materials and 60 percent labour. We observed a similar cost weighting in our preliminary decision.

From this observation, we consider that a weighted X factor should be applied to upfront capital charge. This weighted value is equal to 60 percent of the labour price changes we have forecast for South Australia in this final decision. The weighting of 60 percent was selected because this is about the percentage makeup of the labour component of the annual metering charge and the upfront capital charge. Table 16.10 sets how we derived the X factors.

Table 16.10 Calculation of X factors

	2016–17	2017–18	2018–19	2019–20
Labour cost escalator (unweighted)	0.45	1.00	1.25	1.45
Labour cost escalator (60 percent weighting)	0.27	0.60	0.75	0.87
X factor	–0.27	–0.60	–0.75	–0.87

Source: AER analysis.

[104] AER, *Preliminary decision: SA Power Networks determination 2015–16 to 2019–20*, April 2015, p 16–12.

Our final decision corrects an error in the preliminary decision. In our preliminary decision we mistakenly used the Queensland labour price escalators to derive the values given to the X factors for the upfront capital charge. We have corrected this in our final decision by using the South Australian labour cost escalators.

A–factor

We do not accept SA Power Networks' revised proposal to give the A factor in the control mechanism a non–zero value. This is consistent with our preliminary decision which set the A factor at zero.

In both our preliminary and final decisions our control mechanism for alternative control metering services includes an 'A Factor'. In our final Framework and Approach we stated that the A Factor could be used to adjust for 'residual charges when customers choose to replace assets before the end of their economic life'.[105] Our preliminary decision, however, established a metering tariff structure which did not include such residual charges. Consequently, we concluded that the A factor component of the price control would be given a zero value[106].

SA Power Networks' revised proposal disagreed with this outcome. It stated that the A–factor should be given a non–zero value. This is because a 'non–zero A–factor would allow the AER to make annual adjustments for any under or over–recovery of [alternative control metering] revenue which may arise during the 2015–20 [regulatory control period]'.[107]

For example, SA Power Networks states that it expects to incur a significant under–recovery in its metering expenditure in 2017–18. If the AER was to accept SA Power Networks' proposal, then a non–zero A–factor would provide scope for it to submit a pricing proposal in 2019–20 which adjusts for that under–recovery (if any). This is by:

- providing audited accounts showing that the under–recovery occurred
- proposing that the A factor in the metering price control mechanism be given a value that accounts for the under–recovery in revenue.

We accept that SA Power Networks' proposal is feasible. However, we do not consider it to be required. We have reached this conclusion notwithstanding SA Power Networks' concerns regarding the expansion of metering contestability, which appears likely to occur in the 2015–20 regulatory control period.

We accept that if contestability is expanded, then SA Power Networks may face significant customer "churn". Under our approved structure of metering charges, this would lead to customers discontinuing their payment of the non–capital component of

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105 AER, *Final Framework and Approach for SA Power Networks*, April 2014, p. 76.

106 The form of control in the Framework and Approach is binding on the AER and the distributor. This cannot be amended by the distribution determination made by the AER. A zero value for the A-factor removes this component from the control mechanism.

107 SA Power Networks, *Revised regulatory proposal*, July 2015, p. 430.

their annual metering charge. For SA Power Networks, this may prevent it from recovering its fixed operating costs which, in its view, gives effect to a requirement for a non–zero A factor.

We consider that there are pre–existing mechanisms for dealing with uncertain events. This is a view shared by Energex. In its revised regulatory proposal, Energex stated that the AER should base its assessment on current regulatory obligations.[108] It then stated that 'if or when regulatory obligations are changed then the appropriate mechanism under the NER can be applied'.[109] We agree with this approach; and note that the NER defined pass through events are a potential mechanism for addressing any under or over recovery in costs associated with an expansion of metering contestability.

Finally, SA Power Networks proposed that the A factor should be given a non–zero value to address 'errors of detail and omissions'.[110] This is in relation to the prices the AER set for the upfront capital charge in the 2015–16 year.[111] With respect to this aspect of SA Power Networks' revised proposal, we accept that an error was made. However, instead of addressing it by specifying a non–zero A factor we have decided to approve annual metering capex for new connections (see section 16.6.2 above). Our view is that by providing this additional capex, SA Power Networks will be placed in the same position it would have been in had the error not occurred.

We consider that SA Power Networks' proposal for a non–zero A–factor is not required and, hence, it is not accepted as part of this final decision.

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[108] Energex, Revised regulatory proposal, July 2015, p. 134.

[109] Energex, Revised regulatory proposal, July 2015, p. 134.

[110] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 449.

[111] SA Power Networks, *Revised regulatory proposal*, July 2015, p. 449.

A Approved charges

Table 16.11 Annual metering charge ($ nominal)

Tariff class	Costs	2015/16	2016/17	2017/18	2018/19	2019/20
Type 1–4 'Exceptional' remotely read interval meter	Non–capital	135.07	186.64	181.74	176.97	172.32
	Capital	176.18	217.55	256.44	249.71	243.15
Type 5–6 CT connected manually read meter	Non–capital	73.52	101.60	98.93	96.33	93.80
	Capital	95.90	118.42	139.59	135.93	132.36
Type 5–6 WC manually read meter	Non–capital	8.98	12.41	12.08	11.77	11.46
	Capital	11.71	14.46	17.05	16.60	16.17

Note: Prices for 2016–17 to 2019–20 are indicative only and will be adjusted for actual CPI during the AER's annual pricing approval processes. Type 1-4 'Exceptional' Remotely Read Interval Meters are legacy meters for large customers installed prior to 1 July 2000. Type 5-6 WC Manually Read Meters are the meters that have been typically installed for residential customers.

Table 16.12 AER final decision on X factors for annual metering charges: non–capital component (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	–34.81	5.00	5.00	5.00

Source: AER analysis.

Note: As outlined in section 16.6.4, the X factor has been used to "true-up" the difference between our preliminary and final decisions. Our final decision approves $51.9 ($nominal) in revenue associated with the non–capital component of SA Power Networks' annual metering charges. This is more than the $43.2 million ($nominal) in revenue we accepted at the preliminary decision stage. We have accordingly specified a non–capital X factor in 2016–17 that gives effect to an increase in annual metering prices when used in conjunction with the CPI–X formula. Refer to Table 16.11 in Appendix A for the indicative price changes as result of the above X factors.

Table 16.13 AER final decision on X factors for annual metering charges: capital component (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	–20.47	–15.00	–15.00	–15.00

Source: AER analysis.

Note: As outlined in section 16.6.4, the X factor has been used to "true-up" the difference between our preliminary and final decisions. Our final decision approves $68.5 ($nominal) in revenue associated with the capital component of SA Power Networks' annual metering charges. This is more than the $56.4 million ($nominal) in revenue we accepted at the preliminary decision stage. We have accordingly specified capital X factors

that give effect to an increase in annual metering prices when used in conjunction with the CPI–X formula. . Refer to Table 16.11 in Appendix A for the indicative price changes as result of the above X factors.

Table 16.14 AER final decision on upfront capital charge

Meter	$2015–16
Type 5	
Single element	163.92
Two element	235.02
Three phase	404.13
Type 6	
Single element	102.00
Two element	259.44
Three phase	304.19

Source: AER analysis; SA Power Networks, Approved pricing proposal for 2015–16, 29 June 2015, p. 85

Table 16.15 AER final decision on X factors for upfront capital charge (per cent)

Meter	2016–17	2017–18	2018–19	2019–20
Type 5				
Single element	-17.43	-0.60	-0.75	-0.87
Two element	-17.65	-0.60	-0.75	-0.87
Three phase	-17.39	-0.60	-0.75	-0.87
Type 6				
Single element	-7.64	-0.60	-0.75	-0.87
Two element	-6.57	-0.60	-0.75	-0.87
Three phase	-7.27	-0.60	-0.75	-0.87

Source: AER analysis.

Note: As outlined in section 16.6.4, the X factor in 2016–17 has been used to "true-up" the difference between our preliminary and final decisions. The X factors in 2017–18 to 2019–20 are for labour price growth only.

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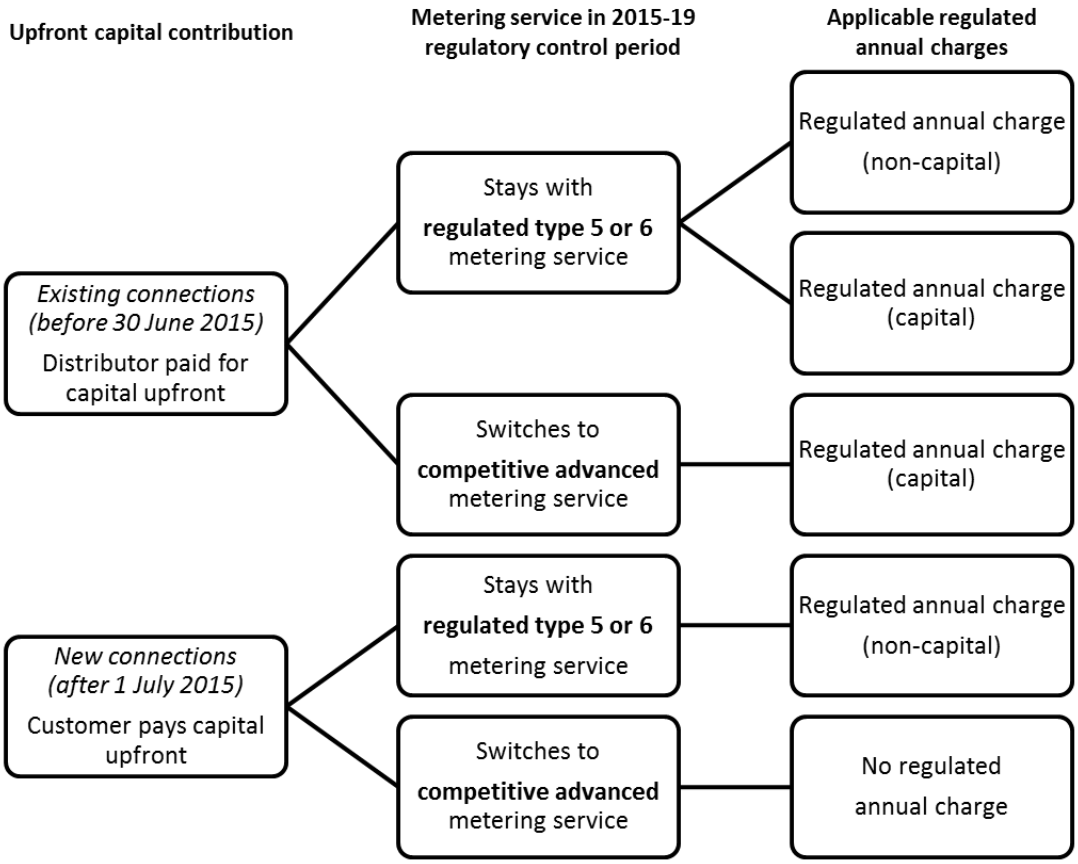
B Annual metering charge

We maintain our preliminary decision approving two types of charges:

1. upfront capital charge for all new and upgraded meters from 1 July 2015
2. annual metering charge comprising of capital and non–capital components

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

Figure 16.3 Final applicable regulated annual 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 metering service, they pay the following charges:

- Capital (MAB recovery[112]) component of regulated annual metering charge
- Non-capital (opex) component of the regulated annual metering charge.

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 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 numbers 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 metering asset base 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 related to new meter connections installed after this date will be added to the metering asset base.

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.

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[112] The MAB is largely the undepreciated value of all existing meters. It will increase slightly in the 2015–20 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 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 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.