FINAL DECISION
Ergon Energy 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 Ergon Energy's 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

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

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Attachment 14 – Control mechanism

Attachment 15 – Pass through events

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Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

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

In this attachment, we set out our final decision on the prices Ergon Energy is allowed to charge customers for the provision of ancillary network services, metering, and public lighting.

16.1 Public Lighting

16.1.1 Final decision

We do not approve Ergon Energy's proposed public lighting charges because we have determined:

- a nominal post-tax weighted average cost of capital (WACC) of 6.01 per cent instead of the proposed 7.41 per cent
- imputation credit assumption of 40 per cent instead of the proposed 25 per cent
- debt raising costs value of 0.0827 per cent instead of the proposed 0.20 per cent.

This final decision adopts the same estimate of WACC as for standard control services. The reasons for the nominal post-tax WACC and imputation credit assumption are discussed in attachment 3 — Rate of return.

In all other respects we have approved Ergon Energy's proposal. Final decision prices for each light type are set out in Table 16.1.

Table 16.1 Final decision prices for public lights, $ day (real 2014–15)

	2015—16	2016—17	2017—18	2018—19	2019—20
Ergon Owned & Operated - Major	0.9997	0.9021	0.9021	0.9021	0.9021
Ergon Owned & Operated - Minor	0.4037	0.4221	0.4221	0.4221	0.4221
Gifted & Ergon Operated - Major	0.5956	0.5443	0.5443	0.5443	0.5443
Gifted & Ergon Operated - Minor	0.2645	0.2777	0.2777	0.2777	0.2777

Source: AER analysis.

Form of control

Our final decision is to apply a price cap for the form of control to public lighting, consistent with the final framework and approach (F&A). Figure 16.1 sets out the control mechanism formulas for public lighting.

Figure 16.1 Public lighting formula

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

where:

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

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

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[1] 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 the X factor for service i in year t, as set out in Table 16.2.

Table 16.2 X Factors for annual public lighting charges (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	-4.52	-4.52	-4.52	-4.52

Source: AER analysis.

A_t^i is an adjustment factor for residual charges when customers choose to replace assets before the end of their economic life.

[1] If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

16.2 Ancillary network services

Our final decision refers to the service groups identified as 'fee based services' and 'quoted services' collectively as 'ancillary network services'. This approach is consistent with our final F&A and how these services are referred to in other jurisdictions.[2]

Ancillary network services share the common characteristic of being non-routine services provided to individual customers on an as requested basis.[3] The existing fee based services and quoted services groupings describe the basis on which service prices are determined.

Prices for fee based services are predetermined, based on the cost of providing the service and the average time taken to perform it. These services tend to be homogeneous in nature and scope, and can be costed in advance of supply with reasonable certainty.

By comparison, prices for quoted services are based on quantities of labour and materials, with the quantities dependent on a particular task.[4] Prices for quoted services are determined at the time of a customer's enquiry and reflect the individual requirements of the customer and service requested. It is not possible to list prices for quoted services in this decision (any such list would only be illustrative purposes).

16.2.1 Final decision

We generally accept Ergon Energy's revised proposal regarding ancillary network services. However, we do not accept its revised proposal X factors or its view that we cease to collectively refer to fee based services and quoted services as ancillary network services. Our reasons are set out in section 16.2.4.

As per our preliminary decision, we will apply price caps as the forms of control for Ergon Energy's ancillary network services.[5] We have amended the price cap formulae descriptions to be consistent with those in Ergon Energy's revised proposal.[6]

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2 AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 45; AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20: Attachment 16—Alternative control services*, April 2015, p. 16–7; AER, *Final Decision: Ausgrid distribution determination 2015–16 to 2019–20: Attachment 16—Alternative control services*, April 2015, p. 16–7; AER, *Final Decision: ActewAGL distribution determination 2015–16 to 2019–20: Attachment 16—Alternative control services*, April 2015, p. 16–6.

3 AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 45; AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20: Attachment 16—Alternative control services*, April 2015, p. 16–17.

4 AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 65.

5 AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20: Attachment 16—Alternative control services*, April 2015, p. 8–9.

6 Ergon Energy, *Submission to the AER on its preliminary determination: Alternative control services–other,* 24 July 2015, pp. 8–10.

We also accept Ergon Energy's proposed upfront capital charges and a proposed quoted service for the installation and provision of type 5 and 6 meters.[7]

Our final decision price cap formulae for fee based services and quoted services are set out in Figure 16.2 and Figure 16.3 respectively. Ergon Energy's 2016–17 ancillary network service prices will be determined by the prices we approved for 2015–16 and the application of these formulae. Our final decision 2015–16 approved prices for Ergon Energy's ancillary network services prices are set out in appendix A.

Form of control—fee based services

Our final decision applies a price cap form of control for fee based services.[8] Under this form of control, we approved a schedule of prices for 2015–16 which are set out in Table 16.16 of appendix A. From 2016–17 and for each subsequent year of the 2015–20 regulatory control period, the year t prices are determined by adjusting the previous year's prices by the formula in Figure 16.2.

Figure 16.2 Fee based ancillary network services formula

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

where:

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

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

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.

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7 Ergon Energy, *Submission to the AER on its preliminary determination: Alternative control services–other,* 24 July 2015, p. 14.

8 AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 67.

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 available alternative index.

X_t^i is:

- for service i in year t that are an upfront capital charge, the X factor as set out in Table 16.3
- for service i in year t that are not an upfront capital charge, the X factor as set out in Table 16.4.[10]

Table 16.3 AER final decision on fee based services up front capital charge X factors for each year of the 2015–20 period (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	–0.25	–0.37	–0.46	–0.55

Source: AER analysis.

Note: To be clear, the labour price growth is positive for each year of the regulatory control period. However, in operating as de facto X factors in the price caps, positive labour price growth is presented as a negative value.

Table 16.4 AER final decision on X factors for fee based services for each year of the 2015–20 period (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	–0.41	–0.61	–0.76	–0.91

Source: AER analysis.

Note: To be clear, the labour price growth is positive for each year of the regulatory control period. However, in operating as de facto X factors in the price caps, positive labour price growth is presented as a negative value.

A_t^i is an adjustment factor for residual charges when customers choose to replace assets before the end of their economic life.

Form of control—quoted services

Our final decision applies a formula to determine the cost build-up of services that are priced on a 'quoted' basis.[11] Figure 16.3 sets out the price cap formula and Table 16.18 in appendix A sets out the approved 2015–16 labour rates for quoted services.

Figure 16.3 Quoted services formula

$$Price = Labour + Contractor\ Services + Materials + Capital\ Allowance$$

[10] If during the 2015–20 regulatory control period Ergon Energy submits a pricing proposal which seeks an adjustment with respect to cl. 11.60.4 of the NER, then the AER can give effect to that proposal using the X factor.

[11] AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, pp. 67–68.

where:

$Labour$ consists of all labour costs directly incurred in the provision of the service which may include labour on-costs, fleet on-costs and overheads. From 2016–17, base labour is escalated annually by $(1+\Delta CPI_t)(1-X_t)$,where:

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities[12] 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 the X factor for service i in year t, as set out in Table 16.4.

$Contractor\ Services$ consists of all costs associated with the use of external labour including overheads and any direct costs incurred. The contracted services charge applies the rates under existing contractual arrangements. Direct costs incurred are passed on to the customer.

$Materials$ consists of the cost of materials directly incurred in the provision of the service, material storage and logistics on-costs and overheads.

$Capital\ Allowance$ represents a return on and return of capital for non-system assets.

16.2.2 Ergon Energy's revised proposal

Ergon Energy's revised proposal generally accepted our preliminary decision on ancillary network services.[13] It accepted the application of price caps for these services and our approach to assessing and determining its prices.[14] However, Ergon Energy's revised proposal contained:

- 2015–16 prices to reflect those approved by the AER in Ergon Energy's 2015–16 pricing proposal which differ from those in the AER's preliminary decision

[12] If the ABS does not, or ceases to, publish the index, then CPI will mean an index which the AER considers is the best available alternative index.

[13] Ergon Energy, *Revised regulatory proposal*, July 2015, p. 67.

[14] Ergon Energy, *Revised regulatory proposal*, July 2015, pp. 54–55; Ergon Energy, *Submission to the AER on its preliminary determination: Alternative control services–other,* 24 July 2015, pp. 10–11.

- updated X factors to reflect its forecast real cost escalators
- eight upfront capital charges for the installation and provision of type 5 and 6 meters on or after 1 July 2015 (during business hours)
- one new quoted service for the installation and provision of type 5 and 6 meters on or after 1 July 2015 (after hours)
- minor changes to the descriptions of some formula components for clarity.[15]

Ergon Energy also stated it does not support collectively referring to fee based services and quoted services as ancillary network services.[16]

With regard to the eight upfront capital charges, Ergon Energy's revised proposal:

- applied the pricing structure set out in our preliminary decision[17]
- rejected our preliminary decision not accepting separate charges for urban and rural customers[18]
- put forward additional upfront capital charges for the installation or upgrade of a site with a current transformer (CT) meter.[19]

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.[20] Ergon Energy applied this aspect of our preliminary decision.[21] Table 16.5 sets out the revised upfront capital charges put forward in its revised proposal, which Ergon Energy disaggregated according to urban and rural locations.

Table 16.5 Revised upfront capital charges ($2015–16)

Meter	Revised proposal
Direct Current	
Single Element, Single Phase – Urban	331.70
Single Element, Single Phase – Rural	514.25
Dual Element, Single Phase – Urban	406.27

15 Ergon Energy, *Submission to the AER on its preliminary determination: Alternative control services–other,* 24 July 2015, p. 1.
16 Ergon Energy, *Submission to the AER on its preliminary determination: Alternative control services–other,* 24 July 2015, p. 11.
17 AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, section 16.2.1.1; Ergon Energy, *Revised regulatory proposal*, July 2015, p. 57.
18 Ergon Energy, *Revised regulatory proposal*, July 2015, p. 71.
19 Ergon Energy, *Revised regulatory proposal*, July 2015, p. 71.
20 AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–20.
21 Ergon Energy, *Revised regulatory proposal*, July 2015, p. 57 and 71.

Dual Element, Single Phase – Rural	588.82
Polyphase – Urban	510.66
Polyphase – Rural	693.21
Current Transformer	
Polyphase – Urban	2426.06
Polyphase – Rural	2775.35

Source: Ergon Energy, *Revised regulatory proposal*, July 2015, p. 71.

16.2.3 Assessment approach

Our preliminary decision sets out our approach to assessing Ergon Energy's 2015–16 ancillary network prices. The same approach has been maintained for our final decision. Particularly in assessing the new type 5 and 6 metering service prices contained in Ergon Energy's revised proposal. This involved assessing the material and non–material (labour) inputs into the proposed charges.

Our assessment of labour price growth is discussed in attachment 7—operating expenditure.

16.2.4 Reasons for final decision

16.2.4.1 2015–16 ancillary network service prices

We accept Ergon Energy's revised proposal to apply its AER approved 2015–16 pricing proposal prices when determining the fee based services and quoted services prices for 2016–17 using the formulae in Figure 16.2 and Figure 16.3. For transparency, these prices are set out in Table 16.16 and Table 16.18 in appendix A.1.

Our preliminary decision set out the 2015–16 prices for Ergon Energy's fee based services and labour rates for quoted services.[22] However, these prices were subsequently adjusted in Ergon Energy's 2015–16 pricing proposal to update for actual CPI, overhead rates and labour on–cost rates. We approved Ergon Energy's 2015–16 pricing proposal in June 2015.

16.2.4.2 X factors

We do not accept Ergon Energy's revised proposal X factors for fee based services that are not an upfront capital charge. We note these X factors are applied in the price cap formulae for labour price growth. We have substituted in our final decision labour price growth which is discussed in attachment 7—operating expenditure.

[22] AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, Appendix A.

16.2.4.3 Upfront capital charge for type 5 and 6 meters

We accept Ergon Energy's adoption of our preliminary decision that the cost of new or upgraded meters is recovered via an upfront capital charge.[23] We also approve the upfront capital charges in Ergon Energy's revised proposal. They are approved in place of the charges we accepted in our preliminary decision.

Our preliminary and final decisions differ in two respects. First, our preliminary decision did not accept Ergon Energy's proposal to charge urban and rural customers separate charges for new or upgraded meters.[24] We have not maintained this position in our final decision and accept that charging urban and rural customers separate charges is reasonable. Second, we have approved higher unit costs for certain inputs into Ergon's charges. This is compared to the unit costs we accepted in our preliminary decision.[25]

We have maintained our preliminary decision that the X factors applicable to the upfront capital charge will be weighted.[26] In particular, they are equal to 60 percent of our assessment of the forecast real labour price increases in Queensland. We have taken this approach because we observed that about 60 percent of the upfront capital charges are made up with a labour component, with the remainder materials. The X factors we have approved are in section 16.2.1.

Urban and rural

We are satisfied that Ergon Energy's revised proposal demonstrates that charging urban and rural customers different charges is reasonable. This is because it should make the prices charged by Ergon Energy more cost reflective. We also accept the assumption Ergon Energy applied in calculating the different prices for urban and rural customers.

We note that Ergon Energy did not initially propose to recover the cost of new or upgraded meters via an upfront capital charge. This is our preferred approach. Before making our preliminary decision, we sent an information request to Ergon Energy notifying it of our position on how the cost of new or upgraded meter meters should be recovered.[27] We also sought input on how the charges should be calculated.[28]

In response, Ergon Energy put forward a proposal which we largely accepted in our preliminary decision.[29] This is with the exception of a proposal to charge "Urban/Short Rural Feeder" customers a different set of prices than "Long Rural/Isolated Feeder" customers.[30] The way in which we should give effect to this arrangement was not

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23 Ergon Energy, *Revised regulatory proposal*, July 2015, p. 56.
24 AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–49.
25 AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–49.
26 AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–49.
27 Ergon Energy, Email to the AER, 15 April 2015.
28 Ergon Energy, Email to the AER, 15 April 2015.
29 AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–49.
30 Ergon Energy, Email to the AER, 15 April 2015.

outlined by Ergon Energy. We nonetheless did not accept the proposal on the basis that an electricity distributor with similar network characteristics (Essential Energy) does not have separate prices for urban and rural customers.[31]

Our position, however, has changed since the preliminary decision. Ergon Energy's network is geographically sparse and has a low customer density. With respect to the installation of new or upgraded meters, these network characteristics are likely to lead to significantly different travel times. This is depending on whether a customer is located in an urban or rural location. To recognise the resulting differences in costs, our final decision is to accept Ergon Energy's proposal. This should lead to more efficient outcomes by increasing the cost reflectivity of Ergon Energy's charges for new or upgraded meters.

With respect to the assumptions Ergon Energy applied, it assumes a travel time of 30 minutes for an urban customer and 2 hours for a rural customer.[32] We found these assumptions to be reasonable. This is because, on average, Ergon Energy has about five customers for every kilometre of line length along its network.[33] We consider this to be indicative of long travel times in rural areas.

Unit costs

We are satisfied that the cost inputs Ergon Energy used are reasonable and, hence, have determined that the revised upfront capital charges should be approved.

We accepted Ergon Energy's initially proposed charges in our preliminary decision because the inputs were within the maximum limits our consultant Marsden Jacob recommended that we should accept. To determine whether we should accept the revised upfront capital charges, we applied the same approach. The inputs we considered are:

- material inputs — the cost of the actual meter installed at a site
- material cost adjustments — for on–costs and a capital allowance
- labour cost adjustments — for on–costs and overheads.

Table 16.6 and Table 16.7 set out our assessment of Ergon Energy's revised material inputs and adjustments, which feed into the revised upfront capital charges. It shows that these inputs and adjustments fall within the maximum limits which Marsden Jacob advised we should accept. On that basis, our final decision is to approve them.

Table 16.6 Material inputs ($2014–15)

	Initial proposal	Revised proposal	Marsden Jacob	Final decision

[31] AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–49.

[32] Ergon Energy, *Revised regulatory proposal: Attachment 05.06.02 Fee based services model_redacted (public)*, July 2015, "Assumptions tab".

[33] AER, *Economic benchmarking regulatory information notice*, "SD 8. Operating environment" tab.

			maximum	
Single phase –one element	100.00	100.00	100.00	100.00
Single phase – two element	150.00	150.00	150.00	150.00
Three phase	189.27	220.00	220.00	220.00
Multi phase (CT)	Not proposed	846.00	Insufficient information	846.00

Source: Ergon Energy, *Revised regulatory proposal: Attachment 05.06.02 Fee based services model redacted (public)*, July 2015, "Inputs tab"; Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

Table 16.7 Material cost adjustments ($2015–16)

	Initial proposal	Revised proposal	Marsden Jacob maximum	Final decision
On-costs ($2015–16) per meter				
Single phase - one element		12.21	25.64	12.21
Single phase - two element		18.31	25.64	18.31
Multi phase (DC)		24.85	25.64	24.85
Multi phase (CT) - 2 man crew		103.27	Not assessed	103.27
Capital allowance per meter				
Single phase – one element – urban/short rural feeder		30.12	Not assessed	30.12
Single phase – one element – long rural/isolated feeder		60.24	Not assessed	60.24
Single phase – two element – urban/short rural feeder		30.12	Not assessed	30.12
Single phase – two element – long rural/isolated feeder		60.24	Not assessed	60.24
Three phase – urban/short rural feeder		30.12	Not assessed	30.12
Three phase – long rural/isolated feeder		60.24	Not assessed	60.24

	Initial proposal	Revised proposal	Marsden Jacob maximum	Final decision
Multi phase (CT) – urban/short rural feeder		200.80	Not assessed	200.80
Multi phase (CT) – long rural/isolated feeder		277.53	Not assessed	277.53

Source: Ergon Energy, *Revised regulatory proposal: Attachment 05.06.02 Fee based services model redacted (public)*, July 2015, "Calculations tab"; Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, section 2.1.1.

Our final decision is to accept the labour rates Ergon Energy proposed for the installation of new or upgraded meters. Information relating to the proposed labour rates is subject to a confidentiality claim. However, without disclosing that information we confirm that Ergon Energy's proposal was within the maximum limits our consultant Marsden Jacob advised that we should accept. This maximum is a raw labour rate of $47.00 per hour ($2014–15).

Additionally, we have determined that Ergon Energy's proposed labour cost adjustments are reasonable. Information relating to these adjustments is subject to a confidentiality claim as well. Nonetheless we confirm that Ergon Energy proposed adjustments were within the maximum limits we have been advised we should accept by our consultant Marsden Jacob. Table 16.8 sets out those limits.

Table 16.8 Labour cost adjustments (percentage)

	Marsden Jacob maximum
On-costs	
Fleet on-costs	11.2
Overheads	
General overhead	43.31
Corporate support overhead	7.57
Total (overheads)	50.88

Source: Marsden Jacob Associates, *Consultant report to the AER on Alternative Control Services*, October 2014, p. 33.

16.2.4.4 Changes to descriptions of components in the price cap formulae

We accept Ergon Energy's revised proposal changes to component descriptions in the price cap formulae as it provides clarity.[34] We note these changes were relatively minor in nature which primarily involved removing redundant text.

16.2.4.5 Use of the term ancillary network services

We do not accept Ergon Energy's revised proposal that our final decision discontinue the use of the term ancillary network services when collectively referring to fee based services and quoted services.[35] We consider collectively referring to these services as ancillary network services creates transparency as it is consistent with our final F&A and how these services are classified and referred to in other jurisdictions.[36] This consistency enables regulators, retailers, policy makers and end users to compare prices for similar services across distributors and across jurisdictions.

16.2.4.6 Call-out fees

We consider that Ergon Energy can charge for wasted attendances in various circumstances. A wasted attendance is an element of the service being provided, but a wasted attendance is not a service in itself.[37] Ergon Energy proposed to charge call-out fees for final meter reads and for other fee-based and quoted services.[38] We consider that these call-out fees reflect the opportunity cost of the fleet and labour Ergon Energy incurs in a wasted attendance. Therefore, we accept Ergon Energy's call-out fees.

16.3 Metering

Our final decision on Ergon Energy's 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 preliminary decision, but have had regard to the likelihood of policy reform in the future through rule changes that will apply during this regulatory period.

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34 Ergon Energy, *Submission to the AER on its preliminary determination: Alternative control services–other,* 24 July 2015, p. 8–10.

35 Ergon Energy, *Submission to the AER on its preliminary determination: Alternative control services–other,* 24 July 2015, p. 11.

36 AER, *Final framework and approach for Energex and Ergon Energy: Regulatory control period commencing 1 July 2015*, April 2014, p. 45; AER, *Preliminary Decision: Ergon Energy determination 2015–16 to 2019–20: Attachment 16—Alternative control services*, April 2015, p. 16–7; AER, *Final Decision: Ausgrid distribution determination 2015–16 to 2019–20: Attachment 16—Alternative control services*, April 2015, p. 16–7; AER, *Final Decision: ActewAGL distribution determination 2015–16 to 2019–20: Attachment 16—Alternative control services*, April 2015, p. 16–6.

37 AER, *Final framework and approach for Energex and Ergon Energy—Regulatory control period commencing 1 July 2015*, April 2014, p. 49.

38 Ergon Energy, *Submission on the Queensland revised regulatory proposals 2015–16 to 2019–20*, 24 July 2015, p. 49.

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.[39]

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.[40] 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'.[41] Other key features of the draft rule change include:

- the transfer of the role and responsibilities of the existing 'Responsible Person' to a new type of Registered Participant called a Metering Coordinator
- allowing any person to become a Metering Coordinator, subject to meeting the registration requirements
- permitting a large customer to appoint its own Metering Coordinator
- requiring a retailer to appoint the Metering Coordinator, except where a large customer has appointed its own Metering Coordinator.[42]

The AEMC's final determination is due 26 November 2015.[43] 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.[44] 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.

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39 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).

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

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

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

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

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

16.3.1 Final decision

16.3.1.1 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.

16.3.1.2 Annual metering services charges

We generally accept Ergon Energy's 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

  Our final decision is to approve an opening MAB value as at 1 July 2015 of $60.7 million compared to Ergon Energy's proposed $61.6 million ($nominal).

- Depreciation

  We maintain our preliminary decision giving effect to standard asset lives of 15 years. This is instead of Ergon Energy's proposal to apply accelerated depreciation of 5 years.[45]

- Rate of return

  Our final decision accepts that the same WACC and imputation credit (gamma) values for standard control services should apply to alternative control metering services. However, unlike standard control, we will not be annual adjusting for return on debt.

  We do not accept Ergon Energy's proposed WACC and gamma values. See attachments 3 and 4 for our decision, along with our reasons.

- Forecast capex

[45] Ergon Energy, *Revised regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, July 2015, p. 30.

Our final decision is to accept $71.1 million in capex and substitute that amount for Ergon Energy's proposed $71.8 million ($2014–15).

- Forecast opex

  In assessing the metering opex building block, we used a base-step-trend approach to developing an alternative forecast. Our cost assessment led us to approve $166.2 million in opex, instead of Ergon Energy's revised proposal of $182.6 million ($2014-15).

Based on our cost assessment of the individual building blocks we rejected Ergon Energy's proposed price caps for annual metering charges. Our substitute price caps are set out in appendix A.

16.3.1.3 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[46] 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:

[46] 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.

for service i (annual metering charge — non–capital component) in year t, the X factor as set out in Table 16.9

for service i (annual metering charge — capital component) in year t, the X factor as set out in Table 16.10

Table 16.9 X Factors for annual metering charges — non–capital component (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	–69.11	4.00	4.00	4.00

Source: AER analysis.

Note: As outlined in section 16.3.5.3, the X factor has been used to "true-up" the difference between our preliminary and final decisions. Our final decision approves $180.6 ($nominal) in revenue associated with the non–capital component of Ergon Energy's annual metering charges. This is more than the $129.0 million ($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 16.20 in Appendix A for the indicative price changes as result of the above X factors.

Table 16.10 X Factors for annual metering charges — capital component (per cent)

	2016–17	2017–18	2018–19	2019–20
X factor	–55.11	–10.00	–10.00	–10.00

Source: AER analysis.

Note: As outlined in section 16.3.5.3, the X factor has been used to "true-up" the difference between our preliminary and final decisions. Our final decision approves $51.3 ($nominal) in revenue associated with the capital component of Ergon Energy's annual metering charges. This is more than the $34.3 million ($nominal) in revenue we accepted at the preliminary decision stage. We have accordingly specified a 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 16.20 in Appendix A for the indicative price changes as result of the above X factors.

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

As return on debt will not be annually adjusted for alternative control metering service charges, the X factors are fixed for the regulatory control period.

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 determination. 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 determinations.

16.3.2 Ergon Energy's revised proposal

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

16.3.2.1 Structure of metering charges

Ergon Energy maintains "that an exit fee (with accelerated depreciation) is the most equitable mechanism for recovering residual metering capital costs".[47]

Despite this general opposition, Ergon Energy's revised proposal applied the structure of metering charges set out in our preliminary decision.[48] 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.[49]

16.3.2.2 Annual metering charge

With regard to the annual metering charge, Ergon Energy's revised proposal:

- applied the general pricing structure set out in our preliminary decision[50]
- submitted a revised capex of $71.8 million for annual metering charges,[51] compared to the AER's preliminary decision accepting $51.3 million ($2014–15)[52]
- submitted a revised opex of $182.6 million,[53] which is more than the $118.8 million we accepted in our preliminary decision[54] and in excess of Ergon Energy's initial proposal for $169.5 million ($2014–15)[55]

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47 Ergon Energy, *Revised regulatory proposal*, July 2015, p. 56.

48 Ergon Energy, *Revised regulatory proposal*, July 2015, p. 57.

49 AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–20; Ergon Energy, *Revised regulatory proposal*, July 2015, p. 57.

50 Ergon Energy, *Revised regulatory proposal*, July 2015, p.57; AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–20.

51 Ergon Energy, *Revised regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, July 2015, p. 19.

52 AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–23.

53 Ergon Energy, *Revised regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, July 2015, p. 26.

54 AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–23.

55 Ergon Energy, *Initial regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, December 2014, p. 24.

- maintained its initial proposal for an opening metering asset base (MAB) value as at 1 July 2015 of $61.6 million,[56] and hence did not accept the AER's preliminary decision to approve $60.7 million[57]
- applied an accelerated depreciation rate of five years to "sunk" default metering assets, rather than the 15 years which we determined in our preliminary decision[58]
- applied depreciation of a newly installed meter to reflect Ergon Energy's understanding of the economic life of a meter in a competitive environment (three years)[59]

The pricing structure which Ergon Energy applied 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.[60] For ease of reference, Appendix B to this attachment provides that information once more.

To derive both the capital and non–capital components of its annual metering charges, Ergon Energy's 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 16.11 shows the forecast metering building block requirement in Ergon Energy's revised proposal. Table 16.12 shows the proposed annual charges for metering services that recover the total revised revenue.

Table 16.11 Ergon Energy's proposed metering building block requirement

($ million, nominal)	2015–16	2016–17	2017–18	2018–19	2019–20
Return on capital	4.6	4.9	4.8	4.4	3.5
Return of capital	11.1	17.9	22.2	28.6	29.9
Operating expenditure	34.8	37.3	39.8	41.9	44.0
Tax liability	2.8	4.2	5.8	7.4	7.2
Total unsmoothed revenue	53.3	64.4	72.5	82.3	84.8

Source: Ergon Energy, *Revised regulatory proposal*, July 2015, p. 60.

[56] Ergon Energy, *Revised regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, July 2015, p. 29; Ergon Energy, *Initial regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, December 2014, p. 27.

[57] AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–23.

[58] Ergon Energy, *Revised regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, July 2015, p. 58.

[59] Ergon Energy, *Revised regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, July 2015, p. 58.

[60] AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, section 16.2.1.1.

Table 16.12 Ergon Energy's proposed annual metering service charges

($/year, nominal)		2015–16	2016–17	2017–18	2018–19	2019–20
Primary	Capital	6.49	33.96	34.96	35.99	37.07
	Non–capital	24.44	50.27	51.74	53.27	54.86
Controlled load	Capital	2.39	12.49	12.85	13.23	13.63
	Non–capital	8.99	18.48	13.02	19.58	20.17
Solar	Capital	1.61	8.45	8.69	8.95	9.22
	Non–capital	6.08	12.50	12.86	13.25	13.64

Source: Ergon Energy, *Revised regulatory proposal*, July 2015, p. 61.

Table 16.12 shows that Ergon Energy is forecasting step changes to the capital components of the annual metering service charges in the 2016–17 pricing year. The step changes are primarily driven by Ergon Energy's proposal to implement a greater rate of depreciation than we accepted in our preliminary decision.[61]

16.3.2.3 Control mechanism

Ergon Energy accepted that the form of control will be a cap on the price of each metering service it provides.[62] It nonetheless sought modifications to the operation of the control formula giving effect to alternative control metering prices.[63] It stated that we should approve:

- a true–up mechanism capable of accounting for differences between 2015–16 prices approved in the preliminary decision and those approved in the final decision
- the use of the X–factor to smooth the revenue recoverable from alternative control metering services in the 2015–20 regulatory control period.[64]

[61] Ergon Energy, *Revised regulatory proposal*, July 2015, p.58; AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–23.
[62] Ergon Energy, *Revised regulatory proposal*, July 2015, p. 57.
[63] Ergon Energy, *Revised regulatory proposal*, July 2015, p. 58.
[64] Ergon Energy, *Revised regulatory proposal*, July 2015, p. 58.

16.3.3 Assessment approach

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

We have followed the same assessment approach in our final decision. Ergon Energy applied the structure of metering services specified in our preliminary decision so our assessment of the distributor's revised proposal focused on its revised costs.

16.3.3.1 Structure of metering charges

Ergon Energy's revised proposal applied the structure of metering charges we approved in our preliminary decision.[65] In considering whether we should maintain this structure in our final determination, we were guided by:

- the AEMC's draft rule change on metering contestability
- the service classification and control mechanism factors in the NER[66]
- SA Power Networks' revised proposal to reallocate the costs attributed to the capital and non–capital components of the annual metering charge.[67]

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'.[68] 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 16.13 sets out the factors which we have considered.

Table 16.13 - 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	The regulatory arrangements (if any) applicable to the

65 Ergon Energy, *Revised regulatory proposal*, July 2015, p. 57; AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–20.

66 NER, cl. 6.2.2(c) and cl. 6.2.5(d).

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

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

Classification factors	Control mechanism factors
service immediately before the commencement of the distribution determination for which the classification is made	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, cll. 6.2.2(c) and 6.2.5(d).

We considered whether the recovery of Ergon Energy's tax liability should be moved from the non–capital component of the annual metering charge, to the capital component. This was a put forward by SA Power Networks in its revised regulatory proposal.[69] We took the view that if we consider the reallocation to be correct, then we should apply it to Ergon Energy.

16.3.3.2 Annual metering charges

To develop its proposed price caps for annual metering services, Ergon Energy's 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 Ergon Energy's revised proposal.

Opening metering asset base

In assessing the proposed opening MAB value, we reviewed how Ergon Energy 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.

Depreciation

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

Forecast capex

Most of Ergon Energy's revised capex forecast for annual metering services comprises of the cost of replacing meters.[70] To assess this aspect of Ergon Energy's forecast

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

70 In its initial proposal Ergon Energy's forecast capex included the cost of new or upgraded connections and replacements. The revised proposal submitted by Ergon Energy, however, only proposes to recover the cost of

capex, we applied the same approach used in our preliminary decision. This required us to consider the revised:

- 'material' and 'non–material' unit costs[71]
- volume of ‘reactive’ and ‘proactive’ replacements.

Forecast opex

We applied a base-step-trend approach to assessing Ergon Energy's proposed opex.

Base

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

Our preference is to use historical data over a five year period 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 data provided by the distributors was prepared according to a consistent set of instructions and definitions.[72]

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 the necessary adjustments to the base so that it only included historic metering opex related to default metering services.

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

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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.

71 Material costs relate to the hardware used to provide metering services. Non–material costs relate to the labour activities which Ergon Energy must perform in order to replace a meter.

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

annual metering opex per customer across non-Victorian distributors in the national electricity market.[73]

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 that 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.[74]

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.[75]

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
- 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.[76]

For capex/opex trade-off step changes, we will assess whether it is prudent and efficient to substitute capex for opex or vice versa.[77]

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[73] 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.

[74] AER, *Expenditure assessment forecast guideline*, November 2013, p. 9.

[75] AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

[76] AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

[77] AER, *Expenditure assessment forecast guideline*, November 2013, p. 11.

Trend

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

16.3.4 Interrelationships

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

Our final decision on Ergon Energy's alternative control metering proposal therefore interrelates with our final decision on rate of return and imputation credits. Please refer to attachments 3 and 4 for the rate of return and gamma values we accept for direct control services, along with our reasons.

16.3.5 Reason for final decision

16.3.5.1 Structure of metering charges

We maintain the same general structure of metering charges specified in our preliminary decision. We, however, have decided to reallocate certain costs between the capital and non–capital components of the annual metering charge. The general structure of metering charges we maintain from our preliminary to final decision 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 applied by Ergon Energy in its revised proposal.[78] In a submission on our preliminary decision, Vector supported our approach too. In particular, it agreed with the removal of exit fees and the method by which we would 'allow distributors… to recover the “residual capital cost” of their efficient regulated investment'.[79] We, however, received submissions from the Queensland Farmers Federation, Origin Energy and the Energy Retailers Association of Australia (ERAA) which were not fully support of our structure of metering charges in our preliminary decision. In deciding whether we should maintain our preliminary decision, we considered those submissions.

The Queensland Farmers' Federation raised concerns with respect to the consultation leading up to the unbundling of meter services. We note these concerns, but given our preliminary decision and the AEMC's draft rule change, we do not consider the AER was in a position to conduct further consultation and meet its timelines under the NER.

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78 Ergon Energy, *Revised regulatory proposal*, July 2015, p. 57.

79 Vector, *Submission on AER preliminary decisions on electricity distribution in Queensland & South Australia for 2015–16 to 2019–20*, 3 July 2015, p. 1.

Further delays would also create further regulatory uncertainty for Ergon Energy and other stakeholders.

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"'.[80] It considered this to be the case because 'a customer taking a smart meter will bear the cost of legacy metering investments for the remaining life of the asset base rather than as a lump sum'.[81]

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 Ergon Energy must be given a reasonable opportunity to recover the costs of its past investments. The manner in which Ergon Energy recovers its legacy metering costs, thus, needs to be considered.

Prior to 1 July 2015 the capital costs Ergon Energy 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 Ergon Energy would be required to 'write–off' unrecovered costs it has incurred upfront, whenever a customer churns. Such an arrangement, however, 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 Ergon Energy with a reasonable opportunity to recover at least its efficient costs.[82] This is inclusive of the capital costs Ergon Energy has incurred for metering services upfront and which it is yet to fully recover.

Additionally, Origin Energy stated, as did the ERAA, that we should give more consideration to the long term implications of the structure of metering charges we accept.[83] 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 is appropriate in the context of expanding competition in metering. This is because it should help level the competitive playing field for new meters by providing transparent standalone

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80 Origin Energy, Submission on AER preliminary decision for Queensland distributors, 3 July 2015, p. 3.

81 Origin Energy, Submission on AER preliminary decision for Queensland distributors, 3 July 2015, p. 3.

82 NER, s. 7A.

83 Origin Energy, Submission on AER preliminary decision for Queensland distributors, 3 July 2015, p. 3; ERAA, Submission on ART preliminary decision for Ergon Energy and Energex, 3 July 2015, p. 2.

prices for all new or upgraded meter connections. It will also shift how Ergon Energy's 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.

With regard to the annual metering charge, we maintain our preliminary decision accepting a two–part tariff comprising of capital and non–capital components. This structure of metering charges is more fully explained in appendix B. In summary, our reason for accepting a two–part tariff is to keep Ergon Energy financially "whole" through the transition to expanded metering contestability.

The Queensland Council of Social Services (QCOSS) stated that the AER's preliminary decision did not take into account any capital or operating savings arising from the installation of smart meters.[84] It submitted that this may lead to customers failing to 'receive any benefit, at least for the next regulatory control period, from the savings arising to distributors from the installation of smart meters'.[85] With respect to this submission, we note that there are mechanisms in the NER to deal with distribution network businesses forecast and actual costs being materially different—such as, the "pass through" provisions.

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.

We have nonetheless determined that the recovery of Ergon Energy's tax liability should change. In our preliminary decision, we included the recovery of tax in the non–capital component of the annual metering charge. We are now of the view that tax should be recovered via the capital component. At the same time as making this final decision for Ergon Energy, we are making a similar determination for SA Power Networks (and Energex). In SA Power Networks' revised proposal, it stated that 'tax liability is interminably linked to the return on capital and relevant depreciation'[86] and so should be allocated to the capital component of the annual metering charge.

We agree with SA Power Networks' observation. Our final decision calculates the tax liability for metering services by using our post-tax revenue model (PTRM). This model in turn calculates a business' tax allowance by using the return on capital and depreciation building blocks as inputs.

Given this, we accept that there is a strong relationship between a business' tax allowance and its capital costs. Our final decision for SA Power Networks therefore accepted the proposal that its tax liability be reallocated to the capital component of its annual metering charge. It follows that we should do the same for Ergon Energy (and

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84 QCOSS, Submission on AER preliminary decision for Queensland distributors, 3 July 2015, p. 28.

85 QCOSS, Submission on AER preliminary decision for Queensland distributors, 3 July 2015, p. 28.

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

Energex). When approached, Ergon Energy agreed that this was a better outcome, compared to the cost allocation in our preliminary decision.[87]

16.3.5.2 Annual metering services

Our final decision is to not accept Ergon Energy's total proposed building block requirement for annual metering services.

We accept a building block approach to setting charges. However, we do not accept Ergon Energy's proposed MAB, approach to depreciation, forecast capex, and forecast opex.

Opening metering asset base

Our final decision is to approve an opening MAB value as at 1 July 2015 of $60.7 million compared to Ergon Energy's proposed $61.6 million ($nominal).

To calculate the opening MAB, we reclassified metering assets from standard to alternative control services. This is consistent with our F&A service classification.[88] Ergon Energy's proposal also moved meters from its standard control services RAB. However, to correct an error in the remaining asset lives, we have made a small change to the amount moved over to the opening MAB value. For more information, see attachment 2.

Depreciation

With regard to the depreciation of Ergon Energy's MAB, we maintain our preliminary decision giving effect to standard asset lives of 15 years. This is instead of Ergon Energy's proposal to apply an accelerated depreciation rate of five years to existing "sunk" default metering assets[89] and three years to newly installed meters.[90]

We accept that there are merits to an accelerated depreciation approach. Among other things, Ergon Energy stated that it would promote efficiency because shorter asset lives would better align the cost recovery of its metering assets and the value that those assets provide to customers.[91] There may also be benefits to depreciating the value of Ergon Energy's metering asset base quickly so that the value of its existing meters can be removed from the MAB.[92] With the opening up of competition, this may minimise the value of residual capital costs in the MAB due to customers churning to alternative metering providers.

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87 Ergon Energy, *Response to AER Ergon 090*, 4 September 2015.

88 AER, *Final framework and approach for Energex and Ergon Energy*, April 2014, p. 54.

89 Ergon Energy, *Revised regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, July 2015, p. 58.

90 Ergon Energy, *Revised regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, July 2015, p. 58.

91 Ergon Energy, *Submission to the AER on its preliminary determination — Metering*, July 2015, p. 15.

92 Ergon Energy, *Submission to the AER on its preliminary determination — Metering*, July 2015, p. 15.

Despite the potential merits to accelerated depreciation, we have not accepted this proposal. This decision is consistent with our general approach that we should apply the current version of the NER. That is, because the AEMC has yet to make its final rule regarding competition in metering, it would be premature to apply accelerated depreciation. We also note, as QCOSS did at the preliminary decision stage, that the development of competition in metering is more likely to emerge in Southeast Queensland (Energex's distribution area) at a faster rate than in regional Queensland (Ergon Energy's distribution area).[93]

We conclude that we will not apply accelerated depreciation. The AER will, however, revisit this issue at the next distribution determination we make for Ergon Energy.

Forecast capex

Our final decision is to accept $71.1 million in capex for annual metering services and substitute that amount for Ergon Energy's proposed $71.8 million ($2014–15). This is an increase on the $51.3 million we accepted at the preliminary decision stage[94] and about 55 percent of what Ergon Energy initially proposed.

Table 16.14 sets out Ergon Energy's initial and revised capex forecast along with our preliminary and final decisions. A key difference between Ergon Energy's initial and revised proposals is the latter's acceptance of our preliminary decision that the cost of new and upgraded meter connections would not be recovered through the annual metering charge. This is shown by a significant reduction in Ergon Energy's proposal for customer initiated capital works. At the initial proposal stage, Ergon Energy forecast $43.6 million for customer initiated capital works, which it revised to $10.5 million[95] following the removal of costs associated with new or upgraded meter connections ($2014–15).[96]

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93 QCOSS, *Submission on QLD regulatory proposals 2015–20*, January 2015, p. 89.

94 AER, *Preliminary decision: Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 16–38.

95 Ergon Energy, *Initial regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, December 2014, p. 16.

96 Ergon Energy, *Revised regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, July 2015, p. 19.

Table 16.14 Ergon Energy's capex proposals and AER decisions ($m, 2014–15)

	Initial proposal	Preliminary decision	Revised proposal	Final decision
Replacements	36.3	22.1	34.9	34.1
Customer initiated capital works	43.6	7.8	10.5	10.5
Other System capex	2.7	2.7	2.6	2.6
Overheads	46.4	18.3	23.8	23.8
Total	128.9	51.3	71.8	71.1

Source: Ergon Energy, *Revised regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, July 2015, p. 19; Ergon Energy, *Initial regulatory proposal: Attachment 05.03.01 Default metering services summary (type 5 & 6 meters)*, December 2014, p. 16; AER, *Preliminary decision: Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 16–38; AER analysis.

Replacements

With respect to Ergon Energy's forecast replacement capex, we considered two factors. These are the proposed unit costs and forecast volumes of replacements. This is the same assessment approach we applied in our preliminary decision.[97]

Unit costs

We maintain our preliminary decision accepting Ergon Energy's non–material and material unit costs. The term "non–material" refers to the labour costs associated with installing a replaced meter. "Material" refers to the actual metering hardware.

In our preliminary decision, we found that Ergon Energy's non–material and material unit costs fit within our acceptable range and hence they were accepted.[98] For the material unit costs, we received advice from our consultant Marsden Jacob Associates. In our preliminary decision, we observed that all of Ergon Energy's material unit costs were within the market ranges in a report Marsden Jacobs provided us.[99] Ergon Energy's revised proposal included the same unit costs. We have therefore decided to accept them in this final decision.

[97] AER, *Preliminary decision: Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 16–29.
[98] AER, *Preliminary decision: Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 16–39 to 16–40.
[99] AER, *Preliminary decision: Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 16–39 to 16–40.

Volumes

Our final decision accepts a replacement forecast of 108 450 meters. We substitute that volume of replacements for Ergon Energy's proposed 124 720. This has a $0.8 million impact on the proposed capex for metering ($2014–15).

We have decided to accept a higher number of meter replacements than in our preliminary decision. Table 16.15 shows our preliminary decision accepted about half of Ergon Energy's replacement forecast. Our final decision, however, accepts about 87 percent.

Table 16.15 Proposed and approved replacement volumes (regulatory requirements)

Description	Reason for replacement	Forecast Initial and revised proposal	Preliminary decision	Final decision
Regulatory obligation				
EMMCO type BAZ meters	Non–compliant	61 219	61 219	61 219
Warburton Franki Type WF2	End of life	42 781	0	42 781
Ferranti Type TM2c	End of life	1 000	0	1 000
EMMCO type MC, AS and HMT	Unidentified non–compliant meters	150	150	150
Enermet K410/Tk410	Failing component	2 000	2 000	2 000
Nilsen EMS 2100	Failing displace	1 300	1 300	1 300
Sub–total		108 450	64 519	108 450
Obsolete meters				
Obsolete metering equipment	15 percent of meters replaced to comply with regulatory obligations	16 270	0	0
Total		124 720	64 519	108 450

Source: AER, *Response to AER Ergon 043 (2)(3)*, 11 February 2015, p. 1–2.

Our preliminary and final decisions differ in relation to two categories of meter replacements. Table 16.15 above shows these are "Warburton Franki Type WF2" and "Ferranti Type TM2c". For both meter categories, our preliminary decision was to not approve their replacement. However, because Ergon Energy has provided further information with its revised proposal, our final decision departs from that outcome and accepts that the meters in both categories should be replaced.

With regard to the Warburton Franki category, we have decided to accept the proposed replacements (42 781 meters) because Ergon Energy provided additional information about its regulatory obligations. In particular, Ergon Energy provided us

with information showing that its initial proposal misrepresented its obligations under Australian Standard 1284.13.[100] We agree that when this was corrected, it was clear that Ergon Energy is under a regulatory obligation to replace the Warburton Franki meters.

Broadly, the error in Ergon Energy's initial proposal overstated the electricity distributor's regulatory requirements in Australian Standard 1284.13. In its initial proposal, for a meter population to be replaced Ergon Energy stated that a sample of that population must fail accuracy limits at both a light **and** full load.[101] The Warburton Franki meters have failed accuracy limits at a light load only. On that basis, our preliminary decision did not accept the replacement of them.[102]

In its revised proposal, Ergon Energy clarified that Australian Standard 1284.13 requires the replacement of a meter population where a sample fails accuracy limits at either a light **or** full load.[103] We agree that this is the correct reading.[104] When it is adopted, we accept that the Warburton Franki category of meters must be replaced. This category fails the accuracy limits set for a light load and hence must be replaced in accordance with Australia Standard 1284.13.

As for the Ferranti TM2 category, Ergon Energy provided further information in its revised proposal regarding why it considered these meters should be replaced. It noted that the population size of these meters is small. Ergon Energy stated that because of this small size, it is more efficient to replace the whole population than to conduct the testing required to determine if replacement should occur.[105] In this particular instance, we agree that this may be the case.

The Ferranti TM2 category is made up of 1000 meters. Under Australia Standard 1284.13, to determine if a population of this size should be replaced, a sample of at least 80 meters must be tested.[106] Given that this relatively small number of meters may be spread out across Ergon Energy's network, identifying their location and visiting each site may be impractical and costly. We also note that at over 50 years of age, the Ferranti TM2 meters are aging. In these circumstances there is a reasonable probability that testing will reveal that they are no longer recording electricity usage within the accuracy limits established in Australia Standard 1284.13. We consider that the proposed replacement of the Ferranti TM2 category is reasonable, given their age and relatively small population.

We have not accepted a category of replacements in this final decision called "Obsolete Metering Equipment". The forecast number of replacements in this category

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100 Ergon Energy, *Submission to the AER on its preliminary determination — Metering*, July 2015, p. 12.

101 AER, *Response to AER Ergon 043 (2)(3)*, 11 February 2015, p. 3; Ergon Energy, *Submission to the AER on its preliminary determination — Metering*, July 2015, p. 12.

102 AER, *Preliminary decision: Ergon Energy's determination 2015–16 to 2019–20*, April 2015, p. 16–43.

103 Ergon Energy, *Submission to the AER on its preliminary determination — Metering*, July 2015, p. 12.

104 Australian Standard 1284.13, Table 1 and 6 (testing by attributes).

105 Ergon Energy, *Submission to the AER on its preliminary determination — Metering*, July 2015, p. 12.

106 Australian Standard 1284.13, Table 1 and 6 (testing by attributes).

is 16 270 meters. It was calculated by adding a percentage allowance on top of the number of meters Ergon Energy forecasts to replace in the 2015–20 regulatory control period. This is to provide 'a financial allowance to perform unexpected additional work while on site to change a targeted meter under the Non-Compliant and End of Life Programs'.[107]

We do not consider Ergon Energy requires a financial allowance to perform unexpected additional work. We maintain our preliminary decision accepting Ergon Energy's proposed corrective maintenance capex allowance. This provides an allowance to cover the corrective maintenance of 49 250 meters in the 2015–20 regulatory control period. We therefore consider the proposal for an additional allowance to perform similar work would provide Ergon Energy with revenue in excess of the amount required to cover its efficient costs. On that basis, the Obsolete Metering Equipment replacement forecast is not accepted.

Overheads

We accept Ergon Energy's proposed overhead allowance of $23.8 million ($2014–15).

Our final decision found that the proposed overhead allowance was calculated in accordance with Ergon Energy's approved cost allocation methodology (CAM).[108] This involved, first, calculating a "shared cost percentage" rate.[109] In accordance with its approved CAM, the next step Ergon Energy took was to multiply that rate by its regulated capex overhead allowance.[110] The result of this calculation is the proposed capex allowance of $23.8 million (2014–15); which we have approved in this final decision.

Forecast opex

Our final decision approves $166.2 million ($2014–15) in forecast metering opex for the 2015–20 regulatory control period.

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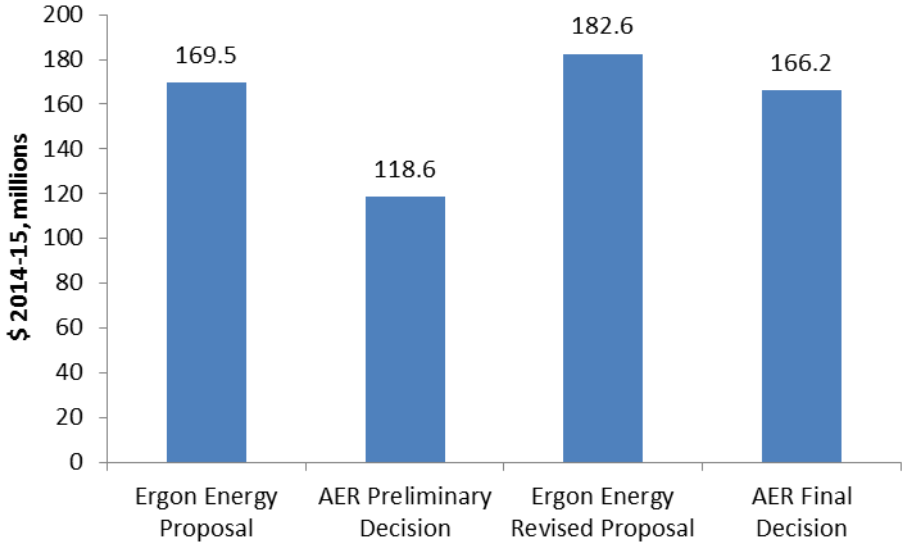
107 Ergon Energy, *Submission to the AER on its preliminary determination — Metering*, July 2015, p. 12.

108 Ergon Energy, 'Cost allocation method', July 2014.

109 This rate is calculated by taking the direct capital costs associated with type 5 and 6 meters and dividing that amount by Ergon Energy's total regulated capex attracting an overhead allowance.

110 Ergon Energy, Revised regulatory proposal, Attachment 05.04.01 MTOverheads data model, tabs "Capex by total spend' and "Input data".

Figure 16.4 Proposed and approved forecast metering opex



Base

As opex is largely recurrent, we use historical opex as the starting point for establishing an efficient base level of opex. As such, the main issue was resolving Ergon Energy's actual historical metering opex.

For the preliminary decision, we relied upon Ergon Energy's economic benchmarking RIN data rather than the revised calculation of historical metering opex included in its initial regulatory proposal.[111]

Ergon Energy maintained in its revised proposal that relying on economic benchmarking RIN data understates its alternative control services metering opex requirements. Ergon Energy explained that this is because it omitted certain metering opex relating to meter queries, maintaining meter equipment, alterations and additions of meters and final meter reads. These amounts had instead been attributed to opex for (standard control) network services.[112]

It has subsequently resubmitted its economic benchmarking RIN data to fix this omission.[113] In making our final decision, we have sourced historical metering opex figures from Ergon Energy's updated economic benchmarking RIN data.

Once we were satisfied with the source data for historical metering opex, we then considered the base period.

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111 AER, *Preliminary decision: Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 16–44.

112 Ergon Energy, *Revised regulatory proposal, Attachment 05.03.01 (Revised) Default Metering Services Summary*, July 2015, p. 27.

113 Ergon Energy, *Response to AER Ergon 077,* 24 July 2015.

In our preliminary decision, we chose to use a five year average instead of a single base year for the following reason:[114]

> 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.

In its revised proposed, Ergon Energy proposed to use the 2013–14 as its base year as it is the most recent financial year for which audited regulatory accounts were available.[115] It did not address our concern about incentives going forward.

We examined the impact if we were to accept a single 2013–14 base. It results in $0.5 million difference in forecast metering opex over the 2015–20 regulatory period.[116] This difference is not material enough for us to depart from the five year average approach which we prefer for the reasons mentioned above.

We agree with Ergon Energy that the most recent data should be included. Therefore, instead of the 2008–09 to 2012–13 period we used for our analysis in the preliminary decision, we have updated our base period to 2009–10 to 2013–14.

As we did in our preliminary decision, we used a partial performance indicator as our benchmarking method which compared Ergon Energy's proposed metering opex per customer against other non-Victorian distribution businesses in the national electricity market. The only difference is that we updated our benchmarking analysis to incorporate the 2013–14 data and using Ergon Energy's revised historic metering opex data.

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

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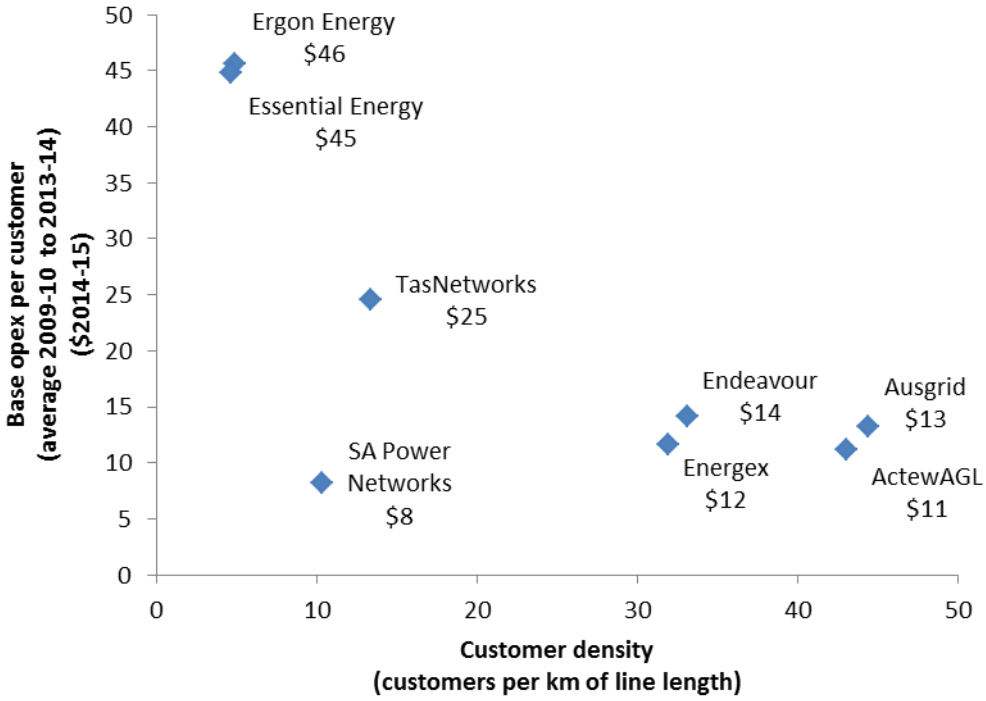
[114] AER, *Preliminary decision: Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 16–30.

[115] Ergon Energy, *Revised regulatory proposal: Attachment 05.03.01 (Revised) Default metering services summary (type 5 & 6 meters)*, July 2015, p. 27.

[116] AER, *Ergon Energy - Final Decision 2015-20 - metering opex analysis*, tab 'trend'.

Figure 16.5 Base metering opex per customer ($2014–15)



We observe a strong correlation between customer density and costs, and so we can reasonably expect Ergon Energy to require no more opex per customer than a distribution business with a similarly dense network. Taking this approach, we consider Essential Energy to be a relevant comparator for Ergon Energy. This is because the two businesses have a similar customer density.

In our preliminary decision, based on the data available at the time, it appeared that Ergon Energy was relatively more efficient than Essential Energy and so we did not make an efficiency adjustment.

However, updating the analysis for Ergon Energy's resubmitted historical metering opex data shows that Ergon Energy is relatively less efficient than Essential Energy. We therefore made a relative efficiency adjustment to Ergon Energy's base opex to lower the forecast metering opex per customer to be in line with Essential Energy.

Step

Ergon Energy included two adjustments to its base year opex:[117]

- a change to an annual in-situ testing program

[117] Ergon Energy, *Revised regulatory proposal: Attachment 05.03.01 (Revised) Default metering services summary (type 5 & 6 meters)*, July 2015, p. 27.

- a requirement to test voltage and current transformers at wholesale metering points which is performed every ten years.

In both cases, the proposed adjustments relate to existing regulatory obligations but where costs involved in meeting those obligations were not incurred (and therefore not included) in Ergon Energy's base year model.

Base opex already reflects the cost of meeting existing regulatory obligations overall. 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 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.

Using a category specific forecasting method for some opex categories may produce better forecasts of expenditure for those categories but this may not produce a better forecast of total opex. If we apply a revealed expenditure forecasting method at the category level, forecast opex for those categories where expenditure is high in the base year will be higher than the efficient level of expenditure. Conversely, forecast opex will be lower than the efficient level for those categories where expenditure is low in the base year. Unless we identify every category of expenditure that is higher or lower than the efficient level, applying a base-step-trend forecasting approach to total revealed costs produces a better total opex forecast.

Ergon Energy's proposed adjustments are not a response to a new regulatory obligation but to existing regulatory obligations. As outlined above, we recognise that a service provider will alter its expenditure over time on specific programs and projects. Moving to an annual testing regime or undertaking testing of voltage and current transformers at wholesale metering points may be areas where Ergon Energy needs to devote additional resources in the 2015–20 regulatory control period. It is a prudent service provider's responsibility to reallocate its opex budget to meet these changing priorities. It generally should not need an increase in its budget to meet existing regulatory obligations.

We therefore do not accept Ergon Energy's proposed adjustments.

Trend

In our preliminary decision, we trended the base forward for forecast metering customer growth and applied zero forecast real price and productivity growth.[118]

As there were no issues raised by Ergon Energy in its revised proposal or by stakeholders in submissions, we maintained this approach in our final decision.

Our alternative forecast for metering opex which arrives at $166.2 million is significantly higher than our preliminary decision of $118.6 million. This is largely due to our decision to accept Ergon Energy's revised historical metering opex numbers.

X factors

We have applied an aspect of Energex's revised regulatory proposal for the 2015–20 regulatory control to Ergon Energy. 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.[119]

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 16.2.4.3) means that there will be no new type 6 metering capital customers for Energex (or Ergon Energy) after 30 June 2015. By contrast, Energex considered customers paying the non–capital component will continue to increase, thus creating a discrepancy.

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 Ergon Energy is in the same circumstances with respect to its charging structure, we have applied the same approach to it. Refer to section 16.3.1.3 above where we set out the approved X factors.

16.3.5.3 Control mechanism

Ergon Energy accepted the control mechanism specified in our preliminary decision.[120] Using this control mechanism, Ergon Energy submitted that we should apply a true–up to account for differences in 2015–16 prices approved in our preliminary decision and those approved in this final decision.

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

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118 AER, *Preliminary decision: Ergon Energy determination 2015–16 to 2019–20*, April 2015, p. 16–46.

119 Energex, *Revised regulatory proposal*, July 2015, p. 140.

120 Ergon Energy, *Revised regulatory proposal*, July 2015, p. 55.

amendment to the control mechanism formula specified in our preliminary decision, and approved in this final decision (see section 16.3.1.3). 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, Ergon Energy will be given an opportunity to recover its efficient alternative control metering costs.

A Approved prices for ancillary network services

A.1 Ancillary network services

Table 16.16 Final decision fee based services ($2015–16)

Service	AER final decision	
	Service undertaken	No service undertaken
Application fee - Basic or standard connection	852.23	0
Application fee - Basic or standard connection - Micro-embedded generators	46.63	0
Application fee - Basic or standard connection - Micro-embedded generators - Technical assessment required	211.71	0
Application fee - Real estate development connection	892.3	0
Protection and Power Quality assessment prior to connection	1320.64	0
Temporary connection, not in permanent position - single phase metered - urban/short rural feeders	561.13	112.23
Temporary connection, not in permanent position - single phase metered - long rural/isolated feeders	897.8	448.9
Temporary connection, not in permanent position - multi phase metered - urban/short rural feeders	561.13	112.23
Temporary connection, not in permanent position - multi phase metered - long rural/isolated feeders	897.8	448.9
Supply abolishment during business - urban/short rural feeders	336.68	112.23
Supply abolishment during business hours - long rural/isolated feeders	673.35	448.9
De-energisation during business hours - urban/short rural feeders	94.03	37.39
De-energisation during business hours - long rural/isolated feeders	561.13	448.9
Re-energisation during business hours - urban/short rural feeders	74.77	37.39
Re-energisation during business hours - long rural/isolated feeders	522.97	448.90
Re-energisation during business hours - after de-energisation for debt - urban/short rural feeders	74.77	37.39
Re-energisation during business hours - after de-energisation for debt - long rural/isolated feeders	522.97	448.9
Accreditation of alternative service providers - real estate developments	866.67	0
Prevented access - one person crew - urban/short rural feeders	52.43	n/a
Prevented access - one person crew - long rural/isolated feeders	209.74	n/a
Prevented access - two person crew - urban/short rural feeders	108.01	n/a

Service		AER final decision
Prevented access - two person crew - long rural/isolated feeders	432.06	n/a

Source: AER analysis.

Note: Prices for no service undertaken are call out fees where the service is not undertaken due to customer fault.

Table 16.17 Final decision fee based services — Upfront capital charge ($2015–16)

Service	AER final decision
Install new or replacement meter (type 5 & 6)—single phase—urban/short rural feeder	331.70
Install new or replacement meter (type 5 & 6)—single phase—long rural/isolated feeder	514.25
Install new or replacement meter (type 5 & 6)—dual element—urban/short rural feeder	406.27
Install new or replacement meter (type 5 & 6)—dual element—long rural/isolated feeder	588.82
Install new or replacement meter (type 5 & 6)—three phase—urban/short rural feeder	510.66
Install new or replacement meter (type 5 & 6)—three phase—long rural/isolated feeder	693.21
Install new or replacement meter (CT)— urban/short rural feeder	2,426.06

Source: AER analysis.

Table 16.18 Final decision quoted services

Quoted services
Application fee – negotiated connection
Application fee – negotiated connection – micro-embedded generators
Application fee – negotiated – major customer connection
Carrying out planning studies and analysis relating to connection applications
Feasibility and concept scoping, including planning and design, for major customer connections
Tender process
Pre-connection site inspection
Provision of site-specific connection information and advice for small or major customer connections
Preparation of preliminary designs and planning reports for major customer connections, including project scopes and estimates
Customer build, own and operate consultation services
Detailed enquiry response fee - EGs 5MW & above

Quoted services
Design and construction of connection assets for major customers
Commissioning and energisation of major customer connections
Design and construction for real estate developments
Commissioning and energisation of real estate development connections
Removal of network constraint for embedded generator
Move point of attachment - single/multi phase
Re-arrange connection assets at customer's request
Protection and Power Quality assessment after connection
Temporary de-energisation - no dismantling
LV Service line drop and replace - physical dismantling
HV Service line drop and replace
Supply enhancement
Provision of connection services above minimum requirements
Upgrade from overhead to underground service
Rectification of illegal connections or damage to overhead or underground service cables
De-energisation after business hours
Re-energisation after business hours
Accreditation of alternative service providers - major customer connections
Approval of third party design - major customer connections
Approval of third party design - real estate developments
Construction audit - major customer connections
Construction audit - real estate developments
Approval of third party materials
Special meter read
Meter test
Meter inspection and investigation on request
Metering alteration
Exchange meter
Type 5 to 7 non-standard metering services
Removal of a meter (Type 5 & 6)
Meter re-seal
Install additional metering

Quoted services
Change time switch
Change tariff
Reprogram card meters
Install metering related load control
Removal of load control device
Change load control relay channel
Services provided in relation to a Retailer of Last Resort (ROLR) event
Non-standard network data requests
Provision of services for approved unmetered supplies
Customer requested appointments
Removal/rearrangement of network assets
Aerial markers
Tiger tails
Assessment of parallel generator applications
Witness testing
Removal/rearrangement of public lighting assets

Source: AER analysis.

Table 16.19 Final decision quoted service ancillary network services hourly labour rates for 2015–16 ($2015–16)

Labour Category	AER final decision on maximum labour charge rates for quoted services, ($2015–16)
Apprentice	N/A
Trainee	N/A
Power Worker	Confidential
Admin Employee	Confidential
Technical Service Person	Confidential
Electrical System Designer	Confidential
Supervisor	Confidential
Para-Professional	Confidential
System Operator	N/A
Professional Managerial	Confidential
Manager	N/A

Source: AER analysis.

A.2 Metering

Table 16.20 Preliminary decision annual metering charge ($ nominal)

Tariff class	Costs	2015–16	2016–17	2017–18	2018–19	2019–20
Primary	Non–capital	24.44	42.36	41.68	41.02	40.36
	Capital	6.49	10.32	11.63	13.11	14.79
Controlled load	Non–capital	8.99	15.58	15.33	15.08	14.84
	Capital	2.39	3.79	4.28	4.82	5.44
Solar	Non–capital	6.08	10.53	10.37	10.20	10.04
	Capital	1.61	2.57	2.89	3.26	3.68

Source: AER analysis.

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.

Table 16.21 Final decision X factors for annual metering charges — non–capital component (per cent)

Non–capital	2016–17	2017–18	2018–19	2019–20
X factor	–69.11	4.00	4.00	4.00

Source: AER analysis.

Note: As outlined in section 16.3.5.3, the X factor has been used to "true-up" the difference between our preliminary and final decisions. Our final decision approves $180.6 ($nominal) in revenue associated with the non–capital component of Ergon Energy's annual metering charges. This is more than the $129.0 million ($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 16.20 in Appendix A for the indicative price changes as result of the above X factors.

Table 16.22 Final decision X factors for annual metering charges — capital component (per cent)

Capital component	2016–17	2017–18	2018–19	2019–20
X factor	–55.11	–10.00	–10.00	–10.00

Source: AER analysis.

Note: As outlined in section 16.3.5.3, the X factor has been used to "true-up" the difference between our preliminary and final decisions. Our final decision approves $51.3 ($nominal) in revenue associated with the capital component of Ergon Energy's annual metering charges. This is more than the $34.3 million ($nominal) in revenue we accepted at the preliminary decision stage. We have accordingly specified a 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 16.20 in appendix A for the indicative price changes as result of the above X factors.

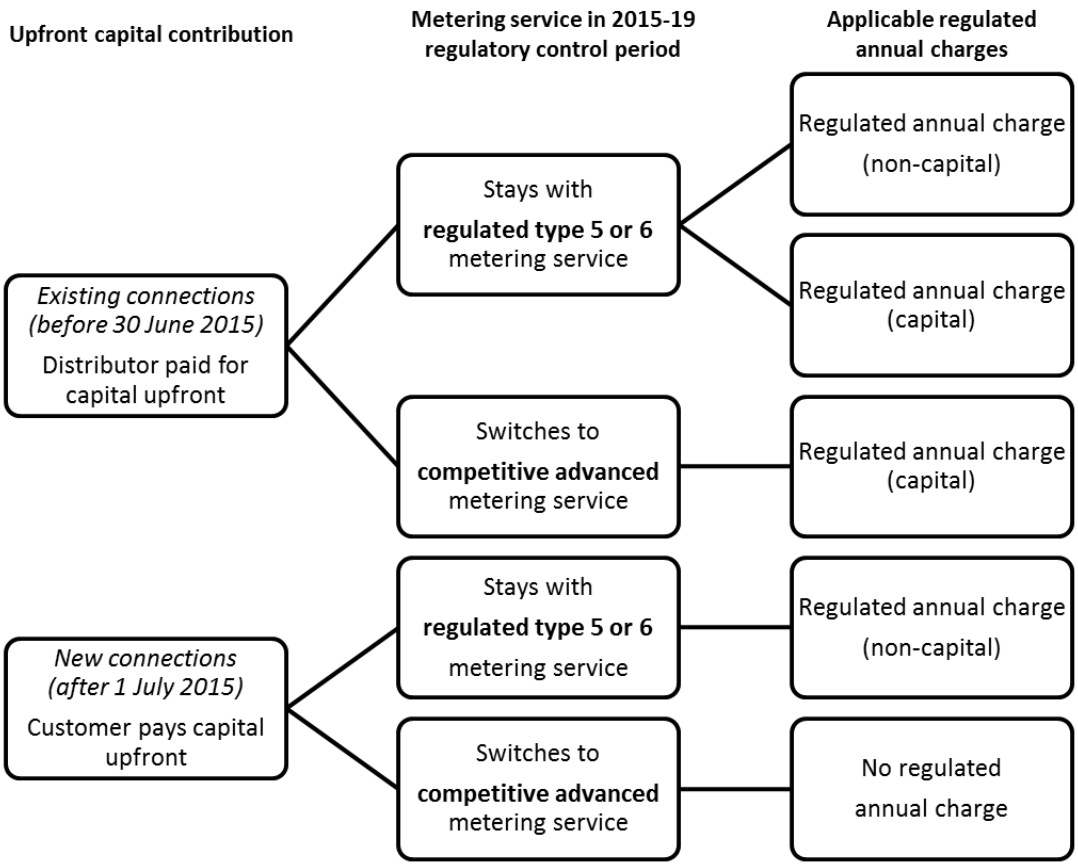
B Annual metering charge

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

Figure 16.6 Final decision – 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[121]) and tax components 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 number of customers who remain with their existing regulated meters are not required to pay the entire capital cost of the MAB. This has the benefit of minimising cross subsidies between customers switching to competitive meters and those remaining on regulated meters. It also means the contribution towards the recovery of the 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 16.6

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

[121] 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.

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

If a customer has a new regulated metering connection on their premises and wants to switch to a competitive advanced metering service (and no longer receives a regulated 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 16.6.