05.03.01

Default Metering Services Summary (Type 5 & 6 meters)

Contents

1. Introduction

1.1 Purpose

The purpose of this Metering Tariff Proposal is to present Ergon Energy's proposed prices and forecasts with respect to Alternative Control Services (ACS) default metering services for the 2015-20 regulatory control period.

Ergon Energy refers to Type 5 and 6 metering installation, provision, maintenance, reading and data services as 'ACS Default Metering Services'.[1]

This proposal has been developed in response to the Australian Energy Regulator's (AER) re-classification of Type 5-6 metering services, from Standard Control Services (SCS) to ACS in its Framework and Approach (F&A) paper for Queensland Distribution Network Service Providers (DNSPs).

1.2 Scope

Following the re-classification of Type 5-6 metering services by the AER, DNSPs are required to develop separate prices for these ACS default metering services. This Metering Tariff Proposal outlines Ergon Energy's approach to developing ACS default metering prices, as well as covering the following: regulatory requirements, capital expenditure forecasts, operating expenditure forecasts, regulatory asset base, annual revenue requirements, metering tariffs and outcomes for customers.

1.3 Summary of expenditure

Ergon Energy is proposing $128.9 million (real $2014-15) in ACS default metering capex for the 2015-20 regulatory control period. This is comprised of $36.3 million for asset replacement, $43.6 million for customer initiated capital works (new connections and upgraded meter installations), $2.7 million in other capex for field based meter configuration capability and $46.4 million in capex overheads.

Ergon Energy is proposing $169.5 million (real $2014-15) in ACS default metering opex over the 2015-20 regulatory control period. It is comprised of $12.9 million for preventative maintenance, $6.0 million for corrective maintenance, $48.5 million for meter reading, $39.8 million for customer services and $62.2 million for opex overheads.

The labour cost of metering alterations and additions has been treated as an ACS quoted service and therefore not included in the ACS default metering expenditure forecast. Details of Ergon Energy's ACS quoted services can be found in Attachment 05.05.01[2].

[1] Ergon Energy, *02.01.01 - Classification Proposal - Final*, October 2014, Table 7, page 19.
[2] Ergon Energy, *05.05.01 Inputs and Assumptions for Alternative Control Services*

2. Regulatory requirements

Ergon Energy's metering prices for the 2015-20 regulatory control period are regulated under Chapter 6 of the National Electricity Rules (NER), which concerns the economic regulation of distribution services and which sets out the terms of the AER's review, including the process and timing. The NER are subject to a series of rule changes proposals currently being considered by the Australian Energy Market Commission (AEMC), as proposed by the AEMC in its Power of Choice review[3]. However, the AER is already aligning its approach as though the Council of Australian Governments' (COAG) rule change request regarding metering services were in effect[4].

Ergon Energy's ACS default metering services are subject to regulatory requirements outlined in the NER, the AER's Framework and Approach Paper, the AER's Expenditure Forecast Assessment Guideline and the Australian Energy Market Operator's (AEMO) Metrology Procedures, along with Queensland specific legislative requirements (as found in the Queensland Electricity Industry Code). Applicable regulatory requirements for the provision of ACS default metering services by Ergon Energy are outlined below.

2.1 National Electricity Rules

The NER specifies the national regulatory framework for classifying regulated services, controlling service pricing and determining prices. This framework is applied by the AER in determining Ergon Energy's proposed prices for ACS default metering services.

2.1.1 Service classification and price control

The AER regulates a variety of services provided by Ergon Energy as a DNSP. Under Chapter 6, Part B of the NER, the AER may classify a distribution service as either a direct control or a negotiated service. Direct control services can be further classified as SCS or ACS. In classifying a service, the NER requires the AER to be consistent with their previous classification unless a different classification is more appropriate[5].

The AER makes a determination to control either the revenue or prices (or both) of direct control services. The basis of the control mechanism is the method used to calculate the revenue to be recovered or prices to be set for a group of services. Whilst the control mechanism for SCS must be in the form of CPI-X (or some other incentive-based variant of this approach), there is no constraint on the control mechanism for ACS, other than that its basis must be stated in the distribution determination[6]. The AER is able to apply a control mechanism to ACS as set out under Chapter 6, Part C of the Rules (Building Block Determinations for SCS[7]). This involves applying the building block approach, although the AER may only apply certain elements of this approach or alternatively, may implement a control mechanism that does not use the building block approach[8].

In practice however, the approach adopted by the AER for determining ACS prices has differed little from the approach adopted for SCS prices[9]. Given the relative level of expenditure involved, the AER's review of ACS default metering services may be less extensive than their review of

[3] AEMC, *Final Report, Power of Choice Review – giving consumers choice in the way they use electricity*, 30 November 2012
[4] AER, *Final Framework and Approach for Energex and Ergon Energy – Regulatory control period commencing 1 July 2015*, April 2014, Appendix C – Rule requirements for Classification
[5] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.2.2 (d)
[6] Ibid, Clause 6.2.6 (b)
[7] Ibid, Clause 6.2.6 (c)
[8] AER, *Final Framework and Approach for Energex and Ergon Energy – Regulatory control period commencing 1 July 2015*, April 2014, Section 2.4, p65
[9] This is illustrated, for example, in the AER's Final Determination for SA Power Networks (formerly ETSA Utilities) for the 2010-15 period. See: AER, *Final decision South Australia distribution determination 2010-11 to 2014-15*, May 2010, pp 254-274

SCS. However, Ergon Energy nonetheless expects a rigorous review, noting the potential for the determination to impact the development of competition in ACS default metering services.

2.1.2 Determining annual revenue requirements

Where the AER chooses to make an ACS determination on the basis of a building blocks approach, the AER must specify the annual revenue requirement for each year based on the following building blocks[10]:

- Indexation of the regulatory asset base (RAB).
- A return on capital for that year.
- The depreciation for that year.
- The estimated cost of corporate income tax of the DNSP for that year.
- The forecast operating expenditure (opex) for that year.

Indexation of the RAB involves the addition of approved capital expenditure (capex), the subtraction of depreciation and the indexation of the asset base using the AER's Roll Forward Model (RFM)[11].

The AER must approve Ergon Energy's proposed capital and operating expenditure forecast included in a building block proposal, if the AER is satisfied that the capex and opex forecasts are[12]:

- The efficient costs of achieving the capex and opex objectives.
- The costs that a prudent operator would require to achieve the capex and opex objectives.
- A realistic expectation of the demand forecast and cost inputs required to achieve the capex and opex objectives.

2.1.3 Distribution pricing rules

The Post Tax Revenue Model (PTRM) is used to determine Ergon Energy's annual building block revenue requirement, with forecast capex, opex and opening RAB and tax asset values and other financial parameters forming key inputs to the PTRM. The allowed revenue is then recovered through tariffs proposed each year by Ergon Energy, for the AER's assessment under the Network Pricing Rules.

The AER must approve a regulatory pricing proposal if satisfied that the proposal complies with Part 1 of Chapter 6 of the NER. The key pricing requirements from Part 1 which are relevant to this Metering Proposal relate to the design of tariff classes, design of tariff components and recovery of allowed revenue.

With regards to the design of tariff classes, tariff classes must group customers together on an ''economically efficient basis", avoiding unnecessary transaction costs and with ACS tariff classes separate to SCS tariff classes. Each customer must be a member of at least one tariff class[13].

Under the Pricing Principles contained within the NER, the revenue to be recovered by each tariff class should lie on or between[14]:

[10] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.4.3 (b)
[11] Ibid, Clause 6.4.3 (b) (1)
[12] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p6
[13] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.18.3
[14] Ibid, Clause 6.18.5 (a)

- An upper bound representing the standalone cost of serving the retail customers who belong to that class.
- A lower bound representing the avoidable cost of not serving those retail customers.

Where a tariff consists of two or more charging parameters, the price for each parameter must take into account the Long Run Marginal Cost (LRMC) of providing the service, having regard to the associated transaction costs and customers' ability and likelihood to respond to price signals. Residual costs are to be recovered in a manner that minimises distortion of efficient service consumption.

2.2 The AER's Framework and Approach Paper

The AER is required to publish an F&A paper at the commencement of each regulatory determination period under Clause 6.8.1 of the NER. The F&A is the first step in determining efficient prices for distribution services and sets out the AER's proposed approach on which services to regulate, the classification of distribution services, the form of the control mechanism and formulae to give effect to the control mechanism (or mechanisms).

2.2.1 Service classification and control

The AER's F&A for Energex and Ergon Energy[15], for the regulatory control period commencing 1 July 2015, sets out its intention to re-classify Type 5 and Type 6 metering services from SCS to ACS. This re-classification means that metering services are no longer part of a bundled charge for standard control services, but that customers pay a cost reflective charge based on the meter installed.

The F&A also stipulates the AER's proposed approach on the form of the control mechanism. For ACS, the AER propose the use of price caps on individual services so as to provide cost reflective benefits.

The AER specifies ACS metering services to include the following sub-services[16]:

- Meter installation.
- Meter provision – selection, procurement, programming, testing and management of National Metering Identifier (NMI) standing data according to the NER.
- Meter maintenance – scheduled maintenance, meter inspection, removal of meter and meter tampering.
- Meter reading – refers to quarterly or other regular reads of meters.
- Meter data services – collection, processing, storage and delivery of metering data, remote or self-reading at difficult to access sites, provision of metering data from the previous two years, ongoing provision of metering data.

The AER's Framework and Approach paper established the control mechanism and the formula for Ergon Energy's different services. For metering the AER has established a price cap form of control and formula to apply. In addition to the information set out in this document, Ergon Energy's supporting document 'Compliance with control mechanisms'[17] provides further detail on how it proposes to comply with the control mechanism and formula set out in the AER's framework and approach paper.

[15] AER, *Final framework and approach for Energex and Ergon Energy – Regulatory period commencing 1 July 2015*, April 2014
[16] Ibid, p114
[17] 04.01.00 Compliance with control mechanism

Although the F&A paper is intended to assist DNSPs in preparing their regulatory proposals and to provide guidance to other stakeholders regarding the AER's likely approach to key regulatory decisions, the AER notes that it may depart from its classification of distribution services and the formulae giving effect to the form of control mechanisms in ''unforeseen circumstances.[18]'' Nevertheless, the F&A paper represents the best available information on which Ergon Energy is able to base its proposal for ACS default metering services on.

2.3 The AER's Expenditure Forecast Assessment Guideline

The AER is required to publish an Expenditure Forecast Assessment Guideline (the Guideline) for DNSPs under Clause 6.2.8 of the NER. The Guideline specifies the approach the AER proposes to use to assess a DNSP's capex and opex forecasts and the information the AER requires to make its assessment[19].

To assess Ergon Energy's revenue proposal, the AER will apply a range of techniques to determine whether proposed expenditures are efficient. These assessment techniques include:

- Economic benchmarking.
- Category level analysis.
- Predictive modelling.
- Trend analysis.
- Cost benefit analysis.
- Project review.
- Methodology review.
- Governance and policy review.

The AER's general approach is to assess the efficiency of a DNSP and determine whether previous spending is an appropriate starting point[20]. The AER expects that Ergon Energy will propose costs that a prudent operator would require to achieve the expenditure objectives under the NER and that this prudent and efficient expenditure represents the lowest long term cost to consumers for the most appropriate investment or activity required[21].

2.4 AEMO's Metrology Procedure

AEMO is required under Clause 7.14.1 of the NER to publish a Metrology Procedure[22], which includes jurisdictionally specific metrology material[23]. The Queensland specific requirements in AEMO's Metrology Procedure are contained within Section 2 and include the following key derogations:

- Queensland metering providers (including Ergon Energy) are not to install Type 5 metering installations, as for any Type 5 metering installations, the volume of electricity to flow through the relevant connection point is to be 0 MWh p.a.[24]

[18] AER, *Final framework and approach for Energex and Ergon Energy – Regulatory control period commencing 1 July 2015*, April 2014, p13
[19] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p4
[20] AER, *Better Regulation factsheet: Expenditure forecast assessment guideline*, November 2013
[21] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p9
[22] AEMO, *Metrology Procedure: Part A National Electricity Market*, July 2012
[23] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 7.14.2
[24] AEMO, *Metrology Procedure: Part A National Electricity Market*, July 2012, Section 2.4.16

- First tier customers who consume up to 750 MWh p.a. can continue to use a Type 6 meter[25].
- For Type 6 metering installations, Ergon Energy must ensure that metering installations are interval meters capable of being upgraded for use in a Type 4 metering installation without replacing the meter[26].
- Ergon Energy must ensure interval meters are not replaced by accumulation meters[27].
- A remotely read interval meter can only be replaced by a manually read Type 6 interval meter if consumption drops below 100 MWh p.a.[28]
- Energy consumed and measured by a Type 6 interval meter must be settled in the wholesale electricity market on the basis of a Type 6 metering installation[29].

Based on the above jurisdictional derogations for Queensland in AEMO's Metrology Procedure, Ergon Energy has installed Type 6 meters in its distribution network.

2.5 Proposed future regulatory changes

Currently the Queensland DNSPs are the monopoly providers of Type 5 and 6 metering services[30]. However, the AER has noted that Type 5 and 6 metering services are likely to become open to more competition in the future[31]. This is consistent with the AEMC's Power of Choice Review final report, which recommended the provision of metering services be contestable and that measures to promote contestability in Type 5 and 6 metering services be pursued[32]. Based on the AEMC's recommendations, the COAG Energy Council (formerly SCER) submitted a Chapter 7 rule change request in October 2013 to enable competition in metering services.

The COAG Energy Council considers that the current regulatory arrangements are inhibiting commercial investment in metering technologies and has proposed changes to the NER to implement arrangements that would support a competitive market for the provision of metering services.

The COAG Energy Council highlights that any new arrangements for the competitive provision of metering services should be simple and practicable from a consumer's perspective. Ultimately, it will be up to consumers to make choices based on the benefits they perceive will be provided by end use services. The benefits to the network system will be realised through the choices consumers make[33].

AEMC released a Consultation Paper[34] on the proposed rule change in April 2014, seeking stakeholder comments on the following issues raised by the COAG Energy Council:

- Establishment of a national framework for metering competition.
- Creation of a new, independent Metering Coordinator role.
- Separation of this role from the network and retailer roles and allowing customer choice.

[25] AEMO, *Metrology Procedure: Part A National Electricity Market,* July 2012, Section 2.4.18
[26] Ibid, Section 2.4.18
[27] Ibid, Section 2.6.1
[28] Ibid
[29] Ibid
[30] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.2.2 (c) (1)
[31] AER, *Final framework and approach for Energex and Ergon Energy – Regulatory period commencing 1 July 2015*, April 2014, p11
[32] AEMC, Final Report, Power of Choice Review – giving consumers choice in the way they use electricity, 30 November 2012, p83
[33] AEMC, *Consultation Paper – National electricity amendment (expanding competition in metering and related services) Rule 2014*, April 2014, p iii
[34] AEMC, *Consultation Paper – National electricity amendment (expanding competition in metering and related services) Rule 2014*, April 2014

- Unbundling of metering service charges from Distribution Use of System (DUoS) charges.
- Setting of customer transfer (exit) fees based on the RAB with a possible cap set by the AER.
- Requirement that pre-existing load management arrangements be supported when replacing meters.
- Requirement that AEMO maintain the national minimum functional specification for smart metering.

Importantly, the proposed rule change allows the states to determine the following key policy and regulatory settings on a jurisdictional basis:

- Minimum functionality requirements for new connections and replacement metering.
- Allowing reversion to lower functionality metering.
- Extension of metering monopolies, e.g. Type 7.

Based on stakeholder submissions to the Consultation Paper and on stakeholder workshops to be held from June-September 2014, the AEMC expects to publish a Draft Rule Determination by 18 December 2014, with a Final Rule and Rule Determination to be published by April 2015[35].

[35] AEMC, *Information Paper – Expanding competition in metering and related services*, p2

3. Capital expenditure

This section presents Ergon Energy's capex proposal for ACS default metering services for the 2015-20 regulatory control period and demonstrates its prudency, efficiency and reasonableness, as required under Section 6.5.7(c) of the NER.

Ergon Energy's ACS default metering capex program is broken up into asset replacement, customer initiated capital works (CICW), other system capex and overheads. The material costs associated with meter alteration and additions and corrective maintenance is treated as capex. The labour installation costs for corrective maintenance is treated as opex while the labour installation cost for meter alterations and meter additions is treated as an ACS quoted service.

This section covers the relevant regulatory requirements, Ergon Energy's key policies and assumptions impacting the metering capex proposal, historical capex trends and benchmarks.

In summary, Ergon Energy is proposing $128.9 million ($2014-15) in capital expenditure for ACS default metering services for the 2015-20 regulatory control period. This is comprised of $36.3 million in asset replacement (end of life, in-situ non-compliant meter families and obsolete meter technology), $43.6 million in customer initiated capital works (new connections and upgraded meters), $2.7 million in other system capex for in field meter configuration capability and $46.4 million in capex overheads.

This level of expenditure represents a 47% real increase in direct ACS default metering capex between the current and forecast regulatory control periods. However, this is entirely due to the increase in the planned meter replacement program. Total direct ACS default metering capex is forecast to increase by $26.4 million between regulatory control periods due to a $32.4 million increase in planned meter replacement capex. The forecast meter replacement program has been implemented based on AER's Replacement Expenditure Model Handbook[36].

The forecast new connections are growing by 2% per annum over 2015-20 and a reduction is forecast between regulatory control periods for the volumes of meter upgrades for solar PV.

The forecast 377,698 meter installations over the 2015-20 period is estimated to be 34% higher than the current 5 year regulatory control period, mainly due to the meter replacement program in 2015-20. Ergon considers that the forecast volume of metering installations is deliverable with its current delivery model which includes a panel of metering service providers to support the internal capability in delivering metering replacement programs.

3.1 Key regulatory requirements

3.1.1 National Electricity Rules

Under the stringent rules for SCS expenditure, the AER is required to approve Ergon Energy's proposed capital expenditure forecasts if it is reasonably satisfied that forecast capex is[37]:

- The efficient cost of achieving the capital expenditure objectives.
- The cost a prudent operator would require to achieve the capital expenditure objectives.
- A realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

[36] AER, Electricity Network Service Provider, Replacement Expenditure Model Handbook, November 2013
[37] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.5.7 (c)

Ergon Energy has structured this proposal on the expectation that the AER will undertake the same approach to the assessment of ACS as to SCS.

3.1.2 AER's capital expenditure assessment approach

The AER intends to assess forecast capex proposals against the NER by using a combination of top down and bottom up approaches[38], with a focus on determining the prudent and efficient level of forecast capex. The AER will assess the need for the expenditure and the efficiency of proposed projects (including consideration of the timing, scope and scale of proposed projects).

For a DNSP to show that their capex forecast is efficient and prudent, the AER expects the DNSP to demonstrate that overall expenditure will result in the lowest sustainable cost (in present value terms) to meet the legal obligations of the DNSP. If Ergon Energy claims higher levels of investment than those required to meet their legal obligations, the AER requires a demonstration that the investment represents the highest net present value of all viable options.

Assessment of capex may include explicit consideration of productivity change over time (based on historical capex) and the AER may benchmark Ergon Energy's historical capex productivity changes with other DNSPs. The AER will likely use top down economic benchmarking to compare Ergon Energy's performance with that of other DNSPs[39]. The AER has indicated that its approach to both capex and opex assessment will place greater reliance on economic benchmarking than it has in the past[40].

3.1.3 AEMO's Metrology Procedure

Under Part A of AEMO's Metrology Procedure, Ergon Energy is a Metering Provider, registered with AEMO, with responsibility for metering installations[41].

As a registered Metering Provider, Ergon Energy must ensure that all meters installed meet the requirements of Section 2.4 of the Metrology Procedure, which includes any guidelines specified by the National Measurement Institute and contained within the *National Measurement Act*, as well as any applicable specifications and guidelines contained within Australian or International Standards[42].

Ergon Energy must also ensure all installed meters meet the requirements of the Metrology Procedure. Under the Metrology Procedure, Ergon Energy is required to provide new metering assets at premises that are either new or upgraded and consume less than 750 MWh p.a. for first tier customers, or less than 100MWh p.a. for second tier customers[43]. Importantly, Type 6 metering installations provided by Ergon Energy as their standard business as usual meter must be capable of a being upgraded for use as a Type 4 (smart meter) metering installation[44].

In terms of Ergon Energy's Metering Asset Management Plan (MAMP), the following requirements under the Metrology Procedure apply:

- The MAMP must comply with the meter inspection and testing requirements under Chapter 7 of the NER, unless AEMO approves an alternative method[45].

[38] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p17
[39] Ibid, p14
[40] Ibid, p12
[41] Ergon Energy's responsibilities as a Metering Provider are documented in Section 2 of AEMO's Metrology Procedure
[42] AEMO, *Metrology Procedure: Part A National Electricity Market*, July 2012, Section 2.4.1, p30
[43] AEMO, *Metrology Procedure: Part A National Electricity Market*, July 2012, Section 2.4.18
[44] Ibid
[45] Ibid, Section 2.7.3

- An acceptable testing practice to measure in-situ compliance of meters will demonstrate compliance with Australian Standards for in-service compliance testing[46].
- The MAMP is required to document testing and inspection requirements[47], and must include description of an accuracy assessment method[48].
- The MAMP must be submitted to AEMO for approval[49].

Ergon Energy's MAMP demonstrates compliance with these requirements and has received approval by AEMO.

3.2 Key policies and assumptions

3.2.1 Capex Forecasting Approach

Ergon Energy's forecasting approach for ACS default metering capex is consistent with the approach it has applied to forecast capex for SCS services. The approach to forecasting capex for both ACS default metering and SCS services involves forecasting direct costs in the expenditure categories of Asset Replacement[50], CICW[51] and Other System Capex and applying escalation and overheads to these direct costs using the same approach.

3.2.2 Cost allocation methodology

Ergon Energy incurs costs during the installation of new or altered network connections, or meter board alterations, which must be allocated between ACS and SCS. Capital expenditure is also subject to corporate overheads, which are allocated in accordance with Ergon Energy's Cost Allocation Method (CAM).

Ergon Energy's CAM was approved by the AER in June 2014 for the next regulatory control period. The CAM sets out Ergon Energy's allocation of costs between regulated and unregulated services, as well as between SCS and ACS categories. Ergon Energy's approach to allocating capex to ACS default metering services is outlined in the supporting documentation[52].

3.2.3 Capital contributions

Ergon Energy is not proposing to apply capital contributions for ACS default metering services in the 2015-20 regulatory control period.

3.2.4 Metering solution

The proposed policy for new connections and replacement metering is to use polyphase meters on all multi-phase installations and single phase meters where a primary or secondary tariff is required. This will reduce the overall meter asset quantities on existing installations. All meters will be installed with import/export displays to cater for the large penetration of solar photo-voltaic (PV) systems.

[46] Ibid, Section 2.7.4
[47] Ibid, Section 2.7.5
[48] Ibid, Section 2.7.6
[49] Ibid, Section 2.7.8
[50] Ergon Energy, *07.00.01 – Asset Renewal Capital Expenditure Forecast Summary*
[51] Ergon Energy, *07.00.03 – Customer Initiated Capital Works Expenditure Forecast Summary*
[52] Ergon Energy, *Cost Allocation Method - Version 4.0 - AER Approved*

The proposed metering strategy[53] recognises the changing regulatory environment and market framework, due to the advent of advanced (or ''smart'') metering. The proposed policy is therefore that all new, upgrade and replacement meter installations will be capable of meeting the national minimum metering specification. Ergon Energy is also planning a targeted deployment of smart meters for network operational purposes where the benefits exceed the costs. For example, high cost service areas including difficult to access sites.

In light of jurisdictional requirements specified in the Metrology Procedure and the likely move to smart metering over the next five to ten years, Ergon Energy's metering policy is to progressively procure meters with contactors and internal power supply for communications modules.

To reduce the costs to customers for a future competitive metering arrangement, we are expecting that our meters (that meet the minimum specification) can be enhanced by adding a communications module, providing the potential to reduce the customer transfer fee and value of the new meter asset for the new provider.

In relation to load control, Ergon Energy's current practice is to install ripple receivers with 1 relay and provision for 3 switches to accommodate for load control of multiple devices. As the load control is part of the SCS, Ergon Energy will continue to utilise a standard device for load control so that the network retains this capability, should a meter be replaced in a contestable rollout. Ergon Energy's proposed policy is to continue with its current practice, however consider alternatives based on the regulatory environment, cost/benefit analysis and other factors.

3.2.5 Meter replacement

Ergon Energy's meter replacement policy is to replace multiple meters used for polyphase installations with a single polyphase meter and to use single phase, two element meters to support sites with separately metered controlled load tariffs where practical.

''End of life'' replacement is based on meter assets that are twice their 'economic life' and display characteristics of failure. This assumes replacement of electro-mechanical meters after 50 years (standard lifetime of 25 years) and electronic metering equipment after 30 years (standard lifetime of 15 years).

3.2.6 Competition assumptions

Ergon Energy is assuming no material competition in metering services will occur over the 2015-20 regulatory control period. This assumption enables Ergon Energy to forecast its capital expenditure requirement based on historical trends and relationships, without the need to estimate the rate of meter churn and level of competition.

It is assumed that the introduction of competition through a Rule change process will constitute a regulatory change event under Clause 6.6.1(a)(1) of the NER, and that the associated cost implications for network billing, network pricing and the range of ACS default metering services (e.g. final reads, etc.) will be considered at that time via a regulatory pass through.

In that event, Ergon Energy would be required to submit to the AER a written statement within 90 business days of becoming aware of the regulatory change event, outlining the costs Ergon Energy believes should be passed onto consumers. The AER would then assess these forecast costs and make a determination on Ergon Energy's cost pass through application, taking into account relevant factors under Clause 6.6.1(j) of the NER.

[53] Ergon Energy, *05.04.04 - Metering Vision and Strategy, October 2014*

3.3 Historical capital expenditure

Ergon Energy's metering expenditure over the current 2010-15 period was largely embedded in its SCS proposal. The AER has developed reporting guidelines over the period, which specifically separate out metering expenditure into a number of capex categories. However these categories are not aligned to the AER's F&A requirements, nor are they mutually exclusive and collectively exhaustive. Ergon Energy has therefore developed reasonable estimates of historical capex that align to its forecasts in order to enable comparison.

Tables 1 to 3 present Ergon Energy's actual and estimated installations, unit prices and total annual expenditure by driver over the 2010-15 regulatory control period.

Table 1 below shows historical direct costs (excluding overheads) for ACS default metering in the 2010-15 regulatory control period. ACS default metering overheads were not recorded for Type 5 and 6 metering services in the 2010-15 period as these services were bundled in with other SCS network services, however they will be recorded for the forecast period to align with the reclassification of these metering services from SCS to ACS.

Table 1: ACS default metering capex for 2010-15 ($m, real $2014-15)

	2010/11	2011/12	2012/13	2013/14	2014/15	2010-15
New Connections	$2.85	$2.91	$3.10	$2.98	$2.88	**$14.72**
Meter Alterations and Additions	$4.23	$7.08	$8.69	$5.09	$4.65	**$29.74**
Planned Meter Replacements	$0.00	$0.00	$0.00	$0.03	$3.86	**$3.89**
Corrective Maintenance	$1.58	$1.33	$1.70	$1.47	$1.58	**$7.67**
Total ACS default metering capex (direct costs only)	**$8.67**	**$11.32**	**$13.49**	**$9.57**	**$13.00**	**$56.05**

Source: Ergon Energy, based on volumes from Ellipse CIS Service Order Data – Financial Year Reports, unit costs from CICW Metering – ACS, CICW Services - ACS and planned meter replacements programs.

Overall, Ergon Energy's direct ACS default metering capex (without overheads) over the current five year regulatory control period is estimated to be $56.1 million, based on actual Type 5 and 6 metering capex unit costs in 2012-13, extrapolated for the rest of the 2010-15 regulatory control period using actual meter installation volumes in each year. The metering capex in 2014-15 is based on estimated volumes and unit costs.

ACS default metering capex ranged from around $8.7 million per annum to as high as $13.5 million at the height of the solar PV installation boom in 2012-13. Over half of this expenditure is for alterations and additions, mainly due to solar PV.

Communications unit costs and capex for 2010-15 are not shown in Table 1 or Table 3 due to the use of a single supplier and the associated need for confidentiality. The volume of communications modules installed in 2010-15 is shown in Table 2 below.

Table 2: ACS default metering installation volumes for 2010-15

	2010/11	2011/12	2012/13	2013/14	2014/15	2010-15
New Connection Service Orders	12,174	12,858	13,852	13,655	13,574	**66,113**
New Connection Meters	13,391	14,144	15,237	15,237	14,850	**72,860**
Alts and Adds Service Orders	24,269	42,047	52,207	31,327	29,412	**179,262**
Alts and Adds Meters	19,415	36,028	43,281	26,882	25,000	**150,606**
Planned Meter Replacements Service Orders	-	-	-	56	12,377	**12,433**
Planned Meter Replacements Meters	-	-	-	56	12,377	**12,433**
Corrective Maintenance Service Orders	23,869	50,097	34,078	20,439	33,333	**161,816**
Corrective Maintenance Meters	9,062	7,898	10,226	9,062	10,000	**46,248**
Communication Units	-	-	-	-	200	**200**
Total ACS default metering service orders	**60,312**	**105,002**	**100,137**	**65,477**	**88,896**	**419,824**
Total ACS default meter installations & replacements	**41,869**	**58,070**	**68,744**	**51,237**	**62,227**	**282,147**

Source: Ellipse CIS Service Order Data – Financial Year Reports.

The volume of metering alterations and additions changed significantly over the 2010-15 period due to the unforeseeable change in the Queensland government support for rooftop solar PV and the associated uptake by customers.

The volume of planned replacements was slowed due to the significant uptake of solar PV installations, uncertainty around smart meter policy and available metering asset data information. The significant uptake of solar reduced the number of sites with BAZ meters that required replacement. The planned meter replacement program was also put on hold due to uncertainty around the future policy and regulatory framework, in particular the smart meter agenda. At the start of the 2010-15 regulatory control period it appeared that there was going to be a large-scale rollout of advanced metering infrastructure in Queensland. The replacement program was also slowed as Ergon Energy had to run an asset data program to identify the location of BAZ meters due to their age and poor legacy records.

Ergon Energy recommenced replacing non-compliant meter families in 2013-14 and will continue these planned replacement programs in the 2015-20 regulatory control period.

Table 3: ACS default metering unit prices for the 2010-15 (real $2014-15)

	2010/11	2011/12	2012/13	2013/14	2014/15
New Connections (Labour and Materials)	$212	$212	$212	$212	$212
Meter Alterations & Additions (Materials)	$158	$158	$158	$158	$158
Planned Meter Replacements (Labour & Materials	-	-	-	$482	$312
Corrective Maintenance (Materials)	$158	$158	$158	$158	$158

Source: Ergon Energy, unit costs from CICW Metering – ACS, CICW Services – ACS and planned meter replacement programs.

Ergon Energy's ACS default metering unit prices for the 2010-15 regulatory control period are based on actual 2012-13 Type 6 costs, as shown in Table 3. The high planned replacement unit cost in 2013-14 was due to a trial of BAZ meter replacement costs in Dalby as part of Ergon Energy's assessment of in-house versus outsourced costs of providing metering services.

3.4 Forecast capital expenditure

Ergon Energy's forecast capital expenditure presented in Table 4 is based on the forecast volume of metering installations per annum, the forecast unit price per installation and forecast overhead costs over the period. The detailed assumptions underpinning Ergon Energy's volume and unit price forecasts are detailed below, along with a demonstration of the deliverability of Ergon Energy's proposed metering ACS default capital program.

Table 4: Forecast ACS default metering capital expenditure for 2015-20 ($m, real 2014/15)

	2015/16	2016/17	2017/18	2018/19	2019/20	2015-20
Asset Replacement	$7.3	$7.3	$7.3	$7.3	$7.3	**$36.3**
Customer Initiated Capital Works	$8.7	$8.7	$8.7	$8.7	$8.7	**$43.6**
Other System Capex	$0.5	$1.1	$0.9	$0.2	$0.0	**$2.7**
Total ACS default metering capex (direct costs only)	**$16.4**	**$17.0**	**$16.9**	**$16.2**	**$16.0**	**$82.5**
Overheads	$8.2	$8.8	$9.7	$9.8	$9.9	**$46.4**
Total ACS default metering capex (direct costs & overheads)	**$24.7**	**$25.9**	**$26.6**	**$25.9**	**$25.9**	**$128.9**

Source: Ergon Energy, individual cost categories in RIN format sheet of MTCapex Data Model and Total ACS default metering capex in Input sheet of MTPTRM Data Model.

Overall, forecast direct ACS default metering capex (without overheads) of $82.5m is 47% higher than the current period of $56.1m. The increase in ACS default metering capex is explained by the $32.4m increase in the planned meter replacement program between regulatory control periods.

The CICW program includes capex materials for new connections, corrective maintenance and alterations and additions and labour for new connections which is comparable between the current and forecast regulatory control periods.

The Other System Capex category includes the cost of hand held devices and associated capability needed for in field configuration management[54].

Capex Overheads were calculated using Ergon Energy's regulatory models. Ergon Energy does not forecast metering IT separately as it is provided by SPARQ, the common IT provider to Ergon Energy and Energex, and allocated to metering via the overheads cost allocation process.

3.4.1 Forecast volumes

Ergon Energy's volume forecasts for metering installations are based on its forecast of new connections and alterations for solar PV installations and tariff related changes, as well as its forecast of corrective, end of life and obsolete meters in its MAMP. In both cases, it is Ergon Energy's view that the forecasting methodologies applied in both cases are based on industry best practice and are consistent with the Guidelines[55].

[54] Ergon Energy, *05.04.06 - Meter Configuration Management System Report*, February 2014
[55] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p17

Table 5 – Forecast ACS default metering installation volumes for 2015-20

	2015/16	2016/17	2017/18	2018/19	2019/20	2015-20
New Connection New Service Orders	13,843	14,036	14,287	14,469	14,595	**71,230**
New Connection Meters	15,227	15,440	15,716	15,916	16,055	**78,353**
Alts and Adds Service Order	30,035	30,224	29,453	29,111	28,678	**147,500**
Alts and Adds Meters	25,530	25,690	25,035	24,744	24,376	**125,375**
Planned Meter Replacements Service Orders	24,944	24,944	24,944	24,944	24,944	**124,720**
Planned Meter Replacements Meters	24,944	24,944	24,944	24,944	24,944	**124,720**
Corrective Maintenance Service Order	32,833	32,833	32,833	32,833	32,833	**164,167**
Corrective Maintenance Meters	9,850	9,850	9,850	9,850	9,850	**49,250**
Communications Modules	400	400	800	1,600	3,200	**6,400**
Total ACS default metering service orders	**102,056**	**102,437**	**102,317**	**102,957**	**104,250**	**514,017**
Total ACS default meter installations	**75,551**	**75,924**	**75,545**	**75,454**	**75,225**	**377,698**

Source: CICW Services - ACS, Reg Reset RIN forecast model,

Overall, Ergon Energy is forecasting a 34% increase in meter installations over the 2015-20 period. This is driven entirely by the significant increase in the volume of planned meter replacements which increase from 12,433 in 2010-15 to 124,720 in 2015-20, based on the analysis detailed in the replacement business case[56].

As discussed earlier, the volume of meter replacements in the 2010-15 regulatory control period was relatively low due to a slowing of the program because of the significant uptake of solar meters, uncertainty around the future policy and regulatory framework and the need to run an asset data program to identify the location of BAZ meters due to their age and poor legacy records. The forecast volume of meter replacements in the 2015-20 period is based on the replacement of meters that have reached the end of their life, non-compliant meter families and obsolete technology, developed in accordance with AEMO requirements.

A flat growth rate of 2% per annum is forecast for the number of new connections over the 2015-20 regulatory control period.

The forecast volume of approximately 25,000 meter alterations and additions for each year of the 2015-20 regulatory control period is based on expected customer initiated demand for meters. This is based on increasing uptake of time of use (TOU) and similar tariffs by customers (10,000 p.a.) and ongoing uptake of solar PV (15,000 p.a.). The strong expected customer uptake of TOU tariffs is lower than the result of 2% growth forecasted per year in the Australian Smart Grids Smart City (SGSC) project. These tariffs are essential in helping the network improve its asset utilization and defer investments in network capital.

This represents a 17% reduction in the volume of alterations and additions meter installations between the 2010-15 and 2015-20 regulatory control periods.

Ergon Energy is also forecasting the installation of 6,400 communications devices and associated metering alterations (where required) for operational reasons, as allowed under Clauses 7.3.4(f), (g) and (h) of the NER. Ergon Energy is permitted to change a site to a remotely read installation where the site is remote or difficult to access. In such cases the meters will remain classified as Type 6 ACS.

[56] *05.04.06 - 00255 Engineering Report Meter Replacement Program*, September 2014

Although the forecast of 377,698 meter installations over the 2015-20 period is 34% higher than the current 5 year regulatory control period, Ergon Energy considers that this forecast volume of metering installations is deliverable without significant changes to its current delivery model, which includes a panel of metering service providers to support the internal capability in delivering metering replacement programs.

Based on the forecast of new connections Ergon Energy is expecting the number of ACS default metering sites to increase from 712,616 to 770,003 by the end of the regulatory control period.

Ergon Energy's forecast breakdown in the number of meters by meter type are based on historical ratios, and are presented in Table 6. This ratio is assumed in the development of new connections, alterations and additions and replacement capex budgets and the associated unit prices for metering.

Table 6 – Forecast metering equipment ratios

Meter Type	Mix
1 Phase	30%
2 Element	56%
3 Phase WC	12%
3 Phase CT	2%

Source: Ergon Energy, Metering asset data.

3.4.2 Unit prices

Ergon Energy's unit prices forecast for metering installations are based on competitively let contracts for specified metering solutions and field services, historical installation support, fleet, tools and site remediation costs, and historical rates of internal field labour productivity.

Table 7 presents estimated unit prices in real 2014-15 dollar terms over the next five years by installation driver. Price estimates reflect the bottom up budgeting process used in the replacement business case divided by the number of installations, while the new connections, alterations and additions reflect recent historical costs. While metering technology prices are expected to decline, this is expected to be muted by the use of fixed price contracts to access volume discounts.

Table 7 – Forecast ACS default metering installation unit prices (real $2014-15)

	2015/16	2016/17	2017/18	2018/19	2019/20
New Connections (Labour & Materials)	$212	$212	$212	$212	$212
End of Life Meters (Labour & Materials)	$300	$300	$300	$300	$300
In-situ Driven Non-Compliant Meter Families (Labour & Material:	$300	$300	$300	$300	$300
Obsolete Meter Technology (Labour & Materials)	$228	$228	$228	$228	$228
Corrective Maintenance (Materials)	$158	$158	$158	$158	$158

Source: Ergon Energy, unit costs from CICW Metering - ACS and planned meter replacement programs.

Ergon Energy's material unit price of $158 per site is based on a mix of meter types required for various metering configurations of new installation, alteration and additions, and corrective maintenance as per Table 6 above. The unit cost for the asset replacement programs (e.g. the end of life and in-situ driven non-compliant meter families) allows for factors such as project management, mobilisation costs and minor switchboard remediation (e.g. meter isolation links). Meter costs in the proposed replacement programs are based on changing out single element meters.

Communications unit prices are not reported here due to the use of a single supplier and the associated need for confidentiality.

By specifying solutions and services that are future proof and integrating market resources where the market can provide services more cost effectively, Ergon Energy is of the view that these unit prices are efficient and prudent, and reasonably likely to occur over the forecast period.

4. Operating expenditure

This section presents Ergon Energy's opex proposal for ACS default metering for the 2015-20 regulatory control period and demonstrates its prudency, efficiency and reasonableness, as required under Clause 6.5.6(c) of the NER.

Ergon Energy's ACS default metering opex is broken into preventative maintenance, corrective maintenance, meter reading, customer services and overheads.

This section covers the relevant regulatory requirements, Ergon Energy's key policies and assumptions impacting the metering opex proposal, historical opex trends and step changes, and forecast opex using the AER's base, step and trend (BST) approach.

In summary, Ergon Energy is proposing $169.5 million ($2014-15) in ACS default metering opex over the 2015-20 regulatory control period. It is comprised of $12.9 million for preventative maintenance, $6.0 million for corrective maintenance, $48.5 million for meter reading, $39.8m for customer services and $62.2 million for opex overheads.

The labour installation cost for alteration or addition meter installations are treated as an ACS quoted service.

This level of expenditure represents a real decrease of almost 6% in direct ACS default metering opex, excluding overheads, between the current and forecast regulatory control periods.

4.1 Key regulatory requirements

4.1.1 National Electricity Rules

Under the NER, the AER is required to approve Ergon Energy's proposed operational expenditure forecasts as included in a building blocks proposal, if reasonably satisfied that forecast opex is[57]:

- The efficient cost of achieving the operational expenditure objectives.
- The cost a prudent operator would require to achieve the operational expenditure objectives.
- A realistic expectation of the demand forecast and cost inputs required to achieve the operational expenditure objectives.

4.1.2 AER's operational expenditure assessment approach

Operational expenditure is almost entirely recurrent, therefore the AER prefers a ''base-step-trend'' approach to the assessment of opex categories[58].

Under this approach, the base year expenditure is assessed to determine whether it is a reasonably prudent and efficient starting point, using the range of criteria described above. Any identified (material) inefficiencies will be used to adjust the base year to an efficiency benchmark base year.

The "revealed cost" approach is the AER's preferred approach to assessing base year opex. If the AER finds that actual expenditure in the base year reasonably reflects the opex criteria, the base year opex will be set to actual expenditure for those cost categories, using the revealed cost approach.

[57] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.5.6 (c)
[58] AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p22

Step changes typically reflect structural shifts in the cost of supply, for example due to changes in the regulatory environment or the impact of an efficient investment on operational expenditure[59]. They can be due to both positive and negative change events, and therefore may be added or subtracted for any other costs not captured in the base opex or rate of change that are required for the forecast opex to meet the opex criteria. If it is efficient to substitute capex with opex, a step change may also be included for these costs, i.e. capex/opex trade-offs.

The trend is estimated using the historical change in output costs as a function of input prices, productivity and output quantities.

The AER notes that when appropriate it will assess opex forecasts using other techniques (determined on a case-by-case basis), or other techniques in combination with the base-step-trend approach, if this will produce an opex forecast more consistent with the opex criteria[60].

4.2 Key policies and assumptions

4.2.1 Cost allocation method

For the 2015-20 regulatory control period, Ergon Energy has allocated ACS default metering operating costs into the following categories, which are explained below:

- Preventative maintenance
- Corrective maintenance
- Meter reading
- Customer services
- Opex overheads

Preventative maintenance is mainly comprised of time based metering equipment testing for direct connected and complex Type 6 installations.

Corrective maintenance includes asset refurbishment, laboratory services and metering asset disposal expenditure.

Meter reading includes quarterly or other regular default meter reading, including internally triggered check reads. It excludes special reads which are classified as ACS quoted services. Opex associated with remotely read Type 6 meters for operational reasons is separately estimated, but reported in the overall meter reading opex.

Customer services includes all other services related to ACS metering opex, including meter investigations and queries (mixed allocation between ACS default metering and ACS quoted services), failed meter replacement, maintaining broken meter seals and maintenance of meter testing equipment.

Opex overheads includes meter data services costs, IT opex and business overheads.

Ergon Energy has assumed a 60% allocation of meter data costs to ACS default metering, with the remaining costs allocated to SCS and Type 1-4 metering. The 60% allocation to ACS default metering is based on a proportional break up of staff and systems used for the provision of Type 6 meter data services.

[59] Ibid, p24
[60] Ibid, p22

Ergon Energy's ACS default metering categories map to the AER F&A approach categories of meter maintenance, reading, data services and opex overheads as shown in Table 8 below.

Table 8: Mapping of Ergon Energy's ACS default metering opex categories to AER F&A categories

AER Framework & Approach	Ergon Energy
Meter Reading	Meter Reading
Meter Maintenance	Preventative Maintenance - ACS
	Corrective Maintenance - ACS
	Customer Services - ACS
Meter Data Services	Opex Overheads
Opex Overheads	Opex Overheads

Source: AER Final Framework and Approach Paper for Energex and Ergon Energy – Regulatory control period commencing 1 July 2015 (April 2014) and Ergon Energy analysis.

4.2.2 Opex Forecasting Approach

Ergon Energy has adopted a BST methodology to forecast its ACS default metering expenditure. This is a change from the bottom-up forecasting approach adopted for the current regulatory control period.

4.2.3 Service Classification

Ergon Energy's policy for the forthcoming regulatory period is to treat all labour costs associated with meter alterations and additions as an ACS quoted service.

4.2.4 Capitalisation

Ergon Energy's policy is to treat the labour costs associated with corrective meter maintenance as an operational expense.

4.3 Historical operational expenditure

The AER's Regulatory Information Notice (RIN) specifically separates out metering expenditure into a number of opex categories, however these categories are not aligned to the AER's F&A requirements, nor are they mutually exclusive and collectively exhaustive. Ergon Energy has therefore developed reasonable estimates of historical opex that align to its forecasts in order to enable comparison.

Tables 9 and 10 present Ergon Energy's estimated historical opex and volumes by category and year over the 2010-15 regulatory control period.

The Other Metering cost category in Table 9 is based on the Other Metering RIN category with costs removed for the following metering services reallocated to SCS and ACS quoted services:

- ACS - General ($11.83 million p.a)
- Network metering ($0.6 million p.a.)
- Revenue protection services ($0.02 million p.a.)
- Preventative maintenance - SCS ($0.06 million p.a.)
- Corrective maintenance – SCS ($0.12 million p.a.).

The numbers in parenthesis are over the five year period.

Table 9: ACS direct default metering opex for 2010-15 ($m, real $2014-15)

	2010/11	2011/12	2012/13	2013/14	2014/15	2010-15
Meter Testing	$ 2.1	$ 1.5	$ 1.7	$ 1.7	$ 1.7	**$ 8.7**
Meter Investigation	$ 2.1	$ 2.4	$ 2.4	$ 2.2	$ 2.2	**$ 11.4**
Scheduled Meter Reading	$ 10.4	$ 10.8	$ 10.5	$ 10.1	$ 9.8	**$ 51.7**
Meter Maintenance	$ 1.4	$ 1.2	$ 1.5	$ 1.3	$ 1.3	**$ 6.8**
Other Metering	$ 4.3	$ 9.4	$ 7.1	$ 6.6	$ 6.4	**$ 33.9**
Total ACS default metering opex (direct with no Alts & Adds)	**$ 20.4**	**$ 25.4**	**$ 23.3**	**$ 22.0**	**$ 21.4**	**$ 112.4**
ACS Metering Alts & Adds Labour	$ 6.5	$ 10.0	$ 11.8	$ 7.8	$ 9.4	**$ 45.6**
Total ACS default metering opex (direct, incl Alts & Adds)	**$ 26.8**	**$ 35.4**	**$ 35.1**	**$ 29.9**	**$ 30.8**	**$ 158.0**

Source: RIN reported expenditure, with adjustments to Other Metering expenditure category as detailed above.

Table 10: ACS default metering opex volumes for 2010-15

	2010/11	2011/12	2012/13	2013/14	2014/15	2010-15
Meter Testing	2,014	1,646	1,644	1,717	10,662	**17,683**
Meter Investigation	10,203	12,053	13,536	10,967	12,185	**58,944**
Scheduled Meter Reading	2,867,032	2,898,213	2,931,745	3,026,647	3,084,957	**14,808,594**
Meter Maintenance	3,920	4,513	4,673	4,509	4,565	**22,180**
Alts and Adds Installs	24,269	42,047	52,207	31,327	29,412	**179,262**

Source: RIN reported volumes.

Overall, historical opex has been relatively flat over 2010-15 in real terms, despite the volume of sites increasing by over 1% per annum over the period. This is due to Ergon Energy's productivity improvements implemented over the regulatory control period, including additional outsourcing where the market was more cost effective than internal resources.

4.4 Forecast operational expenditure

Tables 11 and 12 present Ergon Energy's forecast operating expenditure and volumes by category over the 2015-20 regulatory control period.

Table 11: Forecast ACS default metering opex for 2015-20 ($m, real $2014-15)

	2015/16	2016/17	2017/18	2018/19	2019/20	2015-20
Preventive Maintenance	$2.6	$2.6	$2.6	$2.6	$2.6	**$12.9**
Corrective Maintenance	$1.2	$1.2	$1.2	$1.2	$1.2	**$6.0**
Meter Reading	$9.6	$9.6	$9.7	$9.8	$9.8	**$48.5**
Customer Services	$7.8	$7.9	$8.0	$8.0	$8.1	**$39.8**
Total ACS default metering opex (direct costs)	**$21.2**	**$21.4**	**$21.5**	**$21.6**	**$21.7**	**$107.3**
Overheads	$10.7	$11.2	$12.7	$13.6	$14.0	**$62.2**
Total ACS default metering opex (direct costs & overheads)	**31.9**	**32.6**	**34.1**	**35.1**	**35.7**	**$169.5**

Source: Ergon Energy, MTOpex Data Model, RIN format sheet.

Table 12: Forecast ACS default metering opex volumes for 2015-20

	2015/16	2016/17	2017/18	2018/19	2019/20	2010-15
Meter Testing	3,658	3,657	3,658	3,659	3,662	**18,294**
Meter Investigation	12,185	12,185	12,185	12,185	12,185	**60,925**
Scheduled Meter Reading	3,141,321	3,197,685	3,254,049	3,310,413	3,366,778	**16,270,246**
Meter Maintenance	4,565	4,565	4,565	4,565	4,565	**22,825**
Alts and Adds Installs	25,530	25,690	25,035	24,744	24,376	**125,375**

Source: RIN forecast volumes.

These forecasts were developed using a BST methodology[61], which consists of:

- selecting a base year;
- making appropriate adjustments for non-recurrent items;
- making any further adjustments required to establish an efficient base year;
- identifying and applying any step changes; and
- applying an appropriate trend[62].

By projecting future opex from the 2012-13 base year's revealed costs and trends in productivity, Ergon Energy is of the view that its proposed opex forecast is efficient and prudent, and reasonably likely to occur over the forecast period.

4.4.1 Base Year

2012-13 was chosen as it is the most recent financial year for which audited regulatory accounts were available.

4.4.2 Step Changes

A $1m step change increase has been applied to Preventative Maintenance in 2015-16 to meet AEMO requirements for meter testing and conformance to defined accuracy parameters[63].

[61] ACS default metering overheads were not applied using the BST approach as they are allocated based on direct costs.
[62] Ibid, p31

4.4.3 Trend

Ergon Energy is assuming a 1.6% average annual real cost reduction over the 2015-20 regulatory control period, compared to a 0.3% average annual real cost reduction over the current period.

This assumption is based on historical rates of productivity growth, and identified plans that are expected to impact opex, such as TOU pricing and meter replacements.

Meter replacements will reduce the number of meters per premise and the number of older meters requiring more frequent testing, reducing meter reading and maintenance costs. However, it will increase the number of meter failures. New meters tend to stop working compared to older meters which are more likely to slow down than to fail entirely.

Changes to TOU tariffs to make them more attractive could see a large increase in meter alterations and additions and an associated increase in meter reading and IT costs. This is because TOU pricing requires 3 data streams, compared to the single data stream required for anytime and inclining block tariffs.

[63] Ergon Energy, *06.01.01 - Forecast Expenditure Summary System Operational Expenditure 2015 to 2020*, 19 October 2014, p37

5. Regulatory Asset Base

This section presents Ergon Energy's approach to carving out the ACS default metering opening RAB from the SCS opening RAB for the 2015-20 regulatory control period and presents the resulting depreciation and capital costs estimated using the AER's RFM.

In summary, Ergon Energy's estimated ACS default metering opening RAB is $61.6 million. By the end of the regulatory control period, Ergon Energy estimates the ACS default metering RAB will have reduced to $53.4 million.

5.1 Key regulatory requirements

5.1.1 National Electricity Rules

The NER requires Ergon Energy's RAB, where used in a building blocks determination, to be based on the starting RAB and the AER's RFM[64].

The RAB refers to the value of assets used by Ergon Energy to provide services and must be calculated in accordance with Clause 6.5.1 of the NER. Establishing a starting ACS default metering opening RAB requires the carving out of ACS default metering assets from the SCS RAB.

The NER requires costs to be allocated according to an AER approved CAM, which must comply with the principles outlined in Clause 6.15.2. In order to be approved, the CAM must allocate costs on a causal basis or, if that isn't possible, in a manner that does not distort efficient competition.

In accordance with Clause 6.5.5 of the NER, depreciation for each regulatory year must be calculated based on the value of assets included in the RAB. This value is to be proposed by Ergon Energy in a depreciation schedule which conforms to the following requirements[65]:

- It reflects the economic life of that asset or category of assets.
- It is equivalent to the value of assets when first entered into the RAB.
- It is consistent with depreciation of equivalent assets on a prospective basis.

Clause 6.5.2 of the NER requires that the return on capital be determined such that the "allowed rate of return objective" is achieved. This objective is to be commensurate with the efficient financing costs of a benchmark efficient DNSP with a similar risk profile to Ergon Energy's[66].

5.2 Key policies and assumptions

5.2.1 Asset allocation method

Ergon Energy's ACS default metering asset base is contained in the SCS RAB category of metering, which also contains the asset base for network metering and the value of load control assets at customers' premises. Ergon Energy's policy is to allocate the metering RAB to ACS and SCS based on the estimated depreciated replacement cost of each of the asset sub-classes.

The value of the ACS default metering opening RAB was calculated using the Optimised Depreciation Replacement Cost (ODRC) method. This method calculates the current market value of an asset based on the gross replacement costs of a modern equivalent asset that has been

[64] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.3 and 6.5
[65] Ibid, Clause 6.5.5 (b)
[66] Ibid, Clause 6.5.2 (c)

optimised for a particular purpose and is then adjusted for depreciation to reflect the lifespan of the original asset.

The proposed policy is to apply the ODRC method to value Ergon Energy's opening ACS default metering opening RAB for the following reasons:

1. The ODRC has previously been used to value electricity distribution assets when appropriate historical data was not available. For example, in 2003 the ODRC was proposed by Transend and approved by the Australian Competition and Consumer Commission as the method to value its opening RAB[67].
2. Most opening RAB values for electricity network assets were calculated using ODRC.
3. The ODRC method measures the minimum cost of replicating the system in the most efficient way possible, given its service requirements and the age of the existing assets[68].

The ODRC method generated an ACS default metering opening RAB value of $61.6m. The ODRC was estimated by multiplying the number of regulated Type 5 and 6 assets by their modern equivalent asset price, and reducing this value by depreciation assuming straight line depreciation and standard asset lifetimes. The key inputs used to generate the opening value of Ergon Energy's metering RAB using this method are detailed in Table 13 below.

Table 13: Key assumptions in ACS default metering opening RAB calculation

Inputs	Value	Units	Source
Weighted Average Asset Cost	$373	$/site	$339 per meter, assuming 1.1 meters per site in future
Customers	716,000	NMI	Ergon 2015/16 NMIs
Historical CPI Growth	5.58%	p.a.	ABS QLD average annual CPI for 1971-2013
Historical Household Growth	0.90%	p.a.	ABS QLD average annual population growth, 1971-2013
CPI x Household Growth	106.5%	p.a.	ABS sources above
Metering Asset Life	25	years	Ergon standard metering asset life
ACS default metering opening RAB	**$61.6**	**Million**	

Source: ABS and Ergon Energy ODRC Metering RAB Model.

5.2.2 Depreciation

The proposed policy is to adopt an "accelerated" (5 year) approach to depreciation of the ACS default metering opening RAB. Accelerated depreciation over 3 years could have been applied to reflect the expected average life of metering assets under competition, however 5 years was used to avoid higher short-term metering prices and improve customer metering prices going forward.

Ergon Energy is expensing all meters (new connections, replacements, alterations and additions) over a period of 3 years. The purpose of this approach is to avoid adding forecast capex into the metering RAB.

5.2.3 Weighted average cost of capital

Although ACS are prima facie riskier than SCS due to the exposure to competitive pressures and volume risk, Ergon Energy has adopted the same assumed Weighted Average Cost of Capital (WACC) for its proposal as the one we have applied for SCS.

[67] ACCC, Transend Networks Pty Ltd, Valuation of Transmission Assets, August 2003, page 3
[68] IPART, Regulation of NSW Electricity Distribution Networks, Determination and Rules under the National Electricity Code, December 1999, page xxi.

5.3 Roll Forward Model

Ergon Energy has implemented the AER's PTRM for the purposes of generating the estimates of annual depreciation and capital costs. These costs have been calculated based on the depreciation and WACC policies described above.

Ergon Energy's estimate of depreciation and capital costs is presented in Table 14. The increase in depreciation over the period is due to the 5 year accelerated depreciation of the opening legacy ACS default metering RAB. ACS default metering capex is forecast to be fairly steady for the 2015-20 regulatory control period.

Table 14: Annual depreciation and capital costs ($m, real $2014-15)

$m (nominal)	2015-16	2016-17	2017-18	2018-19	2019-20
Depreciation	11.1	19.9	29.8	40.7	42.6
Capex	26.0	27.9	29.4	29.5	30.1

Source: Ergon Energy, MTPTRM Data Model, Asset Sheet.

Table 15 presents the end of period ACS default metering RAB value. By the end of the regulatory control period, Ergon Energy estimates the ACS default metering RAB will have reduced to $53.4 million.

The reduction in the ACS default metering RAB by the end of the period reduces the market risks faced by the business, and the level of capital charge that customers face through the customer transfer (asset exit) fees.

Table 15 – ACS default metering RAB value ($m, real $2014-15)

	2015/16	2016/17	2017/18	2018/19	2019/20
Metering RAB (start of year)	$61.6	$74.6	$80.4	$78.1	$66.0
Metering RAB (end of year)	$74.6	$80.4	$78.1	$66.0	$53.4

Source: Ergon Energy, MTPTRM Data Model, Asset Sheet.

6. Revenue requirement

This section presents Ergon Energy's annual revenue requirement derived from the AER's PTRM.

In summary, Ergon Energy's estimated annual revenue requirement in the first year is $51.9 million (nominal), which rises on average by 19% per annum in real terms over the period to reach $100.1 million per annum by 2019-20. The smoothed revenue cap for ACS default metering is flat over the 2015-20 forecast regulatory control period at $77.5 million each year.

The main driver of the real increase in ACS default metering costs over the period is the move to a sustainable level of capex with the implementation of Ergon Energy's planned replacement program and accelerated depreciation of the opening RAB, which will reduce customer's annual metering charges in the subsequent regulatory control period after 2015-20.

6.1 Regulatory requirements

6.1.1 National Electricity Rules

Where the AER makes a determination on the basis of a building blocks approach, it must specify the annual revenue requirement. The manner in which Ergon Energy is to calculate its annual revenue requirement for each year of the regulatory control period is set out in the AER's PTRM[69].

The AER's PTRM utilises the "accrual building blocks" approach to revenue modelling. The following building blocks are summed in the model to determine the annual revenue requirement:

- Return on capital.
- Return of capital (regulatory depreciation).
- Operating and maintenance expense.
- Estimated taxation liability.

The principal inputs to the PTRM comprise the following:

- RAB and tax asset base, as determined by the RFM.
- Forecast capital expenditure.
- Forecast operating and maintenance expenditure.
- Financial parameters, including CPI and the elements of the WACC calculation.

6.2 Key policies and assumptions

The key policies and assumptions driving the PTRM results include the assumed corporate tax rate, imputation credits (gamma) and forecast inflation.

6.2.1 Corporate tax rate

Ergon Energy has assumed a 30% rate of corporate tax. This is the same assumption made in its SCS proposal.

[69] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.4.2 (a)

6.2.2 Gamma

Ergon Energy has assumed a 25% rate for imputation credits. This is the same assumption made in its SCS proposal.

6.2.3 Inflation

Ergon Energy has assumed the same forecast rate of inflation as that used in its SCS submission.

6.3 Post Tax Revenue Model

Ergon Energy has used the building blocks approach to determine the forecast revenue requirements for ACS default metering services over the 2015-20 regulatory control period based on the proposed opex, capex and RAB inputs already discussed. A building block approach calculates the total revenue requirements by summing up the return on capital, annual opex requirements and other costs (such as tax and indirect overheads).

Ergon Energy's annual revenue requirement, as calculated using the AER's PTRM, is shown in Table 16. The model shows required revenue increasing from $51.9 million in 2015-6 to $100.1 million by 2019-20, with the smoothed revenue cap flat across the 2015-20 period at approximately $77.5 million each year, so that annual ACS default metering prices are flat.

Table 16 – ACS default metering revenue requirement by Year ($m, nominal)

	2015/16	2016/17	2017/18	2018/19	2019/20
Return on Capital	$4.94	$6.14	$6.78	$6.75	$5.85
Return of Capital	$11.05	$19.88	$29.78	$40.68	$42.55
O & M	$32.80	$34.39	$36.92	$38.98	$40.60
Tax	$3.11	$5.56	$8.22	$11.04	$11.12
ACS default metering revenue requirement	**$51.90**	**$65.96**	**$81.69**	**$97.45**	**$100.13**
ACS default metering smoothed revenue cap	**$77.44**	**$77.44**	**$77.45**	**$77.45**	**$77.46**

Source: Ergon Energy, MTPTRM Data Model, X Factor sheet.

The increase in unsmoothed revenue over the regulatory control period is driven by the move to a sustainable level of capital investment and accelerated depreciation of the ACS default metering opening RAB.

7. Metering tariffs

The purpose of this section is to outline the tariffs Ergon Energy is proposing for ACS default metering services, which are aligned with Ergon Energy's network tariff classification.

7.1 Key regulatory requirements

7.1.1 National Electricity Rules

There are no specific provisions in the NER governing ACS tariffs, nor has the AER provided specific guidance regarding metering ACS charges in its F&A paper.

Ergon Energy has therefore assumed that the AER will require ACS charges to comply with the same requirements as specified for SCS charges. The requirements for SCS charges are governed by the Distribution Pricing Rules, as set out in Clause 6.18 of the NER.

The Distribution Pricing Rules require that tariff classes group customers on an economically efficient basis, avoid unnecessary transaction costs[70] and that the revenue expected to be recovered by each tariff class lies on or between[71]:

- an upper bound representing the standalone cost of serving retail customers who belong to that class;
- a lower bound representing the avoidable cost of not serving those customers.

Further requirements under the Distribution Pricing Rules are set out in the "Regulatory requirements" section above.

7.2 Key policies and assumptions

In developing its ACS default metering charges, Ergon Energy has considered all options available in accordance with the NER. The proposed policy therefore does not consider the alternative option of re-bundling residual sunk metering asset costs through DUoS instead of exit fees, in the way that the AER is considering for the NSW DNSPs' 2014-19 regulatory determinations but which may require changes to the NER.

Ergon Energy has developed the following types of ACS default metering charges to recover the annual revenue requirement from customers:

- An annual metering service charge for the primary metering service.
- A supplementary charge for each secondary controlled load.
- A supplementary charge for solar.
- A customer transfer (exit) fee for customers choosing another provider if competition is introduced.

Ergon Energy is proposing metering tariffs which are largely aligned to its network tariffs. Each metering tariff has been set on a cost reflective basis, based on Ergon Energy's estimate of the forward looking costs to service that particular type of network tariff.

[70] AEMC, *National Electricity Rules*, Version 62, April 2014, Clause 6.18.3 (d)
[71] Ibid, Clause 6.18.5 (a)

7.2.1 Customer classification approach

Following a review of the ACS default metering cost drivers, Ergon Energy has determined that it will classify Type 6 basic metering installations according to the number of primary and secondary metering services they receive. This classification is based on analysis of annualised costs, which demonstrated that the capital charge was the most significant element, and was based on the number of measurement elements required.

Customers on primary tariffs are those with Type 6 metering with or without solar PV. Customers with secondary metering services are those on a primary service with at least one controlled load service.

The introduction of an interval meter based metering solution in the future could lead to a significant difference between customers on basic metering installations compared to those using interval data. However, there are presently no plans to introduce an interval meter capability for the ACS default metering service.

7.3 Customer Transfer Fee

The proposed policy is to apply customer transfer (exit) fees where customers with Type 6 meters churn to an alternative metering provider. The Customer Transfer Fee is based on the administration and metering asset costs associated with a customer transferring to an alternative provider, as shown in Table 17.

Table 17 – Customer transfer charges per site (real $2014-15)

	2015/16	2016/17	2017/18	2018/19	2019/20
Customer Transfer Admin Fee	$50.53	$53.10	$57.21	$60.66	$63.44
Customer Transfer Asset Fee	$86.44	$102.69	$108.50	$103.34	$85.68
Total Customer Transfer Fee	**$136.97**	**$155.78**	**$165.71**	**$164.00**	**$149.13**

Source: Ergon Energy ACS Meter Pricing Model.

The Customer Transfer Asset Fee is based on the average residual value of Ergon Energy's Type 6 metering assets per customer, calculated by the forecast metering RAB divided by the number of active primary tariffs in the relevant year. Table 17 shows that the Customer Transfer Asset Fee over the 2015-20 period is in the range of $86-$109 per primary service. The Customer Transfer Asset Fee declines after 2017-18 as the size of the ACS default metering RAB reduces due to accelerated depreciation of the opening metering RAB.

The Customer Transfer Admin Fee is calculated based on 35 minutes of an Administration Employee's time to process the removal of the customer and their metering assets from Ergon Energy's systems. This is based on 25 minutes to remove and dispose of the meter and 10 minutes to change the customer status and relay this information.

This is based on the standard hourly labour rate, including on-costs and overheads, for an Administration Employee. The Customer Transfer Admin Fee increases each year in accordance with Ergon Energy's labour escalation rate.

The proposed approach to apply a customer transfer fee and these assumptions are consistent with COAG's Rule change proposal and the approaches adopted by NSW DNSPs.

7.4 Annual service charges

Ergon Energy's proposed annual ACS default metering service charges have been set based on the required revenue each year, the cost allocation weighting between primary, controlled load and solar metering services, and the forecast number of services each year.

Table 18 shows the relative costs of primary, controlled load and solar and the proportion of ACS default metering revenue assigned to each tariff category. The relative costs are based on the net present value of forecast ACS default metering capex and opex, weighted by the cost allocation between primary, controlled and solar metering services.

Table 18 – Proportion of ACS default revenue by tariff category for 2015-20

Tariff Category	Relative Cost	% allocation of revenue to Tariff Category
Primary	100%	78%
Primary and controlled load	37%	18%
Primary and solar	25%	4%

Source: Ergon Energy ACS Meter Pricing Model.

The primary tariff applies for remotely read Type 6 meters where the remotely read capability was initiated by Ergon Energy for operational purposes (e.g. access or remote site). An ACS quoted service applies in the case where a customer requests a remotely read meter.

Tables 19, 20 and 21 present the annual revenue requirement, annual number of services and annual service charge and customer class. The total ACS default metering revenue requirement shown in Table 19 is the same as the total ACS default metering annual revenue requirement shown in Table 16 from the PTRM results.

Table 20 shows the volume of ACS default metering services for primary, controlled load and solar.

Table 19 – Annual ACS default metering revenue requirement ($m, real $2014-15)

	2015/16	2016/17	2017/18	2018/19	2019/20
Primary	$60.79	$60.72	$60.66	$60.61	$60.57
Controlled Load	$14.25	$14.05	$13.86	$13.68	$13.51
Solar	$2.40	$2.68	$2.93	$3.16	$3.38
Total ACS default metering revenue requirement	**$77.44**	**$77.44**	**$77.45**	**$77.45**	**$77.46**

Source: Ergon Energy ACS Meter Pricing Model.

Table 20 – Annual ACS default metering services

	2015/16	2016/17	2017/18	2018/19	2019/20
Primary	712,616	726,652	740,939	755,408	770,003
Primary and controlled load	454,229	457,363	460,553	463,784	467,043
Primary and solar	113,077	128,767	143,802	158,546	172,922

Source: Ergon Energy ACS Meter Pricing Model.

The annual ACS default metering prices, shown in Table 21, are calculated by dividing the revenue requirement for primary, controlled load and solar services by the volume of services in each of these tariff categories.

Table 21 – Annual ACS default metering charges (real $2014-15)

	2015/16	2016/17	2017/18	2018/19	2019/20
Primary	$85.31	$83.56	$81.87	$80.23	$78.66
Primary and controlled load	$116.68	$114.28	$111.97	$109.73	$107.58
Primary and solar	$106.52	$104.33	$102.22	$100.18	$98.22

Source: Ergon Energy ACS Meter Pricing Model.

The primary plus controlled load charge assumes one controlled load only. Each additional controlled load would incur an incremental charge. The primary with solar charge incorporates the primary service charge.

Ergon Energy is of the view that the proposed charges for annual ACS default metering services are consistent with the NER, being between the stand alone and avoidable cost of the service.

8. Customer outcomes

The purpose of this section is to explain to the reader how Ergon Energy has considered the benefits and risks to customers in its proposal and have incorporated feedback from consumers and other stakeholders into its metering expenditure forecasts.

8.1 What are metering services?

"Metering services" is a term developed by the AER to group classes of services relating to meter installation. The AER has divided metering services into three categories:

- Types 1-4 metering services – these meters record detailed energy usage and have a number of other capabilities, the most significant being remote communications facilities. These meters are provided in a competitive market and are therefore not regulated by the AER.
- Type 5 and 6 metering services – Type 5 meters record energy data in 30 minute intervals, and are manually read, typically every three months. A Type 6 meter is a "general purpose" meter that records accumulated energy consumption and is also manually read.
- Type 7 metering services – Type 7 services apply where AEMO has decided that a metering installation does not require a meter. Examples of such instances include street, traffic, park and community lighting meters.

As the AER has determined in its F&A paper to separately regulate the services associated with Type 5 and 6 metering installations, these services have been the focus of this document. The "business as usual" default meter installed by Ergon Energy is a Type 6 meter. The terms "basic", "accumulation" and "Type 6" may be used inter-changeably.

Metering assets are quite different to other distribution asset categories, being relatively low cost, and subject to movement.

Ergon Energy's corporate objectives which relate to metering services are as follows:

- Deliver a prudent and efficient program of works for metering services.
- Ensure meter assets are fit for purpose and comply with metrology requirements.
- Ensure meter assets are suitable and deliver customer requirements.
- Meet legal and regulatory obligations associated with metering services.

Ergon Energy has approximately 1.3 million Type 6 meters connected to its distribution network, with no Type 5 meters installed.

8.2 Customer engagement strategy

Ergon Energy has initiated a broad program of customer and stakeholder engagement in preparation for its 2015-20 regulatory proposal and documented this in the document titled '0A.01.04 - Informing Our Plans, Our Engagement Program'[72]. This program has provided Ergon Energy with key insights to customer concerns regarding metering and other network services. The outcomes of this engagement program have been used as inputs into the submission to provide detail on customer expectations regarding level of service, reliability and investment.

[72] Ergon Energy, *0A.01.04 - Informing Our Plans, Our Engagement Program*, October 2014

Ergon Energy engaged with the Customer Council in 2014 on proposed ACS default metering tariffs for the forecast 2015-20 regulatory control period[73]. This included discussion on the AER's reclassification of Type 5-6 metering services from SCS to ACS, options for the development of ACS default metering tariffs and exit fees and metering charges which had been applied or proposed in other Australian states.

Ergon Energy's approach to customer engagement has been reviewed and refined on an ongoing basis during the preparation of the 2015-20 regulatory proposal. This has ensured a timely approach to two-way communication and supports Ergon Energy in the delivery of efficient and affordable network services.

8.3 Customer Impact Assessment

Ergon Energy considered the impact of various input assumptions on the prices that customers would pay for provision of metering services associated with Type 5 and 6 meter installations. The input assumptions were optimised to generate reasonable customer metering prices for the 2015-20 and subsequent regulatory control periods.

The various input assumptions were as follows:

- User pays contributions – assessing the options of not applying upfront charges or applying them where a customer requires a new connection or a meter upgrade (alteration or addition).
- Valuation of the ACS default metering opening RAB – two valuation approaches were considered to determine the most appropriate opening value.
- Depreciation of the ACS default metering opening RAB – assessing whether to depreciate the opening metering RAB over its remaining accounting book life of 14 years or accelerate its depreciation over 5 years to reduce the size of the RAB in future and improve customers metering prices.
- Capitalisation approach – whether expenditure for part or all of forecast metering capex should be treated as an expense (opex) to reduce the amount of metering capex added to the metering RAB.
- Customer Transfer (exit) fee – the appropriate level of customer transfer fee to apply where metering competition is introduced into Type 5 and 6 metering and customers transfer to an alternative provider.

The different assumptions were modelled and the different metering pricing outcomes considered. As a result of this analysis, the following parameter settings were ultimately selected:

- A capitalisation approach to expense everything in order to avoid adding additional capex into the metering RAB, to minimise asset stranding risk and to improve metering price outcomes for customers going forward.
- Valuing the metering RAB using the ODRC as this lowers the unit cost for customers.
- Accelerating the depreciation of the meter asset value and 3 year depreciation of meter installations to minimise stranding asset risk and improve metering price outcomes for customers going forward.
- A relatively low customer transfer fee to remove barriers for customer market entry and therefore align with the direction of national metering competition policy.

[73] Energeia, *0A.02.07 - ACS Metering Tariffs for 2015-20, Customer Council Working Group Meeting,* 18 June 2014

8.4 Comparison against other DNSPs

Ergon Energy tends to have higher costs than other DNSPs due to its significant network area and low customer density. A detailed assessment of Ergon Energy against other Australian DNSPs is outlined in the supporting document *0A.02.01 - Huegin - Ergon Benchmarking Report*[74].

As a result of its network characteristics, Ergon Energy has few comparable peers in the electricity distribution industry. One DNSP that is approximately comparable is Essential Energy in rural NSW which also has a relatively low customer density and large line length.

Table 22 below provides a comparison of Ergon Energy's metering pricing settings for 2015-20 against those proposed by Essential Energy in its 2014-19 regulatory proposal.

Table 22: Ergon Energy and Essential Energy's ACS default metering pricing approaches

1	Opening MAB	Ergon Energy	Essential Energy
	a. Valuation approach	ODRC Method	RAB Carve out
	b. Opening MAB Value ($M) - 2015	$62m	$118m
	c. Closing MAB Value ($M) - 2020	$53m	$79m
	e. Depreciation of Opening MAB (yrs)	5 years	7 years
2	**Annual Metering Tariffs (average of 5 year forecast)**		
	a. Primary Tariff	$82	$51
	b. Controlled Load	$112	$71
	c. Solar	$102	$107
3	**Customer Transfer Fee (average of 5 year forecast)**		
	a. Customer Transfer Admin Fee	$57	$56
	b. Customer Transfer Asset Fee	$97	$61
	c. Total Customer Transfer Fee	$154	$117
4	**General (average across 5 year forecast)**		
	a. Customers (average)	741,123	826,743
	b. Meters (average)	1,201,717	1,567,809
	c. ACS Default Metering Revenue Requirement	$77m	$59m

Source: Essential Energy – Attachment 8.7 Charges for Type 5 and 6 metering services model and Ergon Energy Analysis.

Ergon Energy has a higher annual ACS default metering prices for a primary service compared to Essential Energy due to a combination of the following factors:

- Essential Energy and the other NSW DNSPs are charging customers for the cost of new or additional meter and installation, while Ergon Energy is only charging for labour in some cases. If Ergon Energy were to adopt the same policy, it is estimated to reduce Ergon Energy's annual ACS default metering prices by approximately 13%.
- Ergon Energy has higher direct ACS default meter replacement capex (excluding overheads and escalation) than Essential Energy over the forecast regulatory control period. Ergon Energy's forecast replacement capex of $36.3m (real $2014-15) for 2015-20

[74] Huegin, *0A.02.01 - Ergon Energy Expenditure Benchmarking – Partial Productivity and Cost Driver Analysis and Comparisons,* October 2014, p3

is higher than Essential Energy's forecast of $33.4m (converted to real $2014-15) for their 2014-19 regulatory control period[75].

- Ergon Energy has a smaller number of services, so lower economies of scale
- Ergon Energy has depreciated its opening ACS default metering RAB over a shorter 5 year accelerated period compared to 7 years for Essential Energy. Ergon Energy's more aggressive depreciation approach will assist in minimising stranding asset risk and improve metering price outcomes for customers in the longer term.
- Ergon Energy has higher metering expenditure per service due to a larger network area, lower customer density and the Queensland legislative requirement to install interval capable meters.

Ergon Energy and Essential Energy have a comparable Customer Transfer Administration Fee of approximately $50. The difference in the Customer Transfer Asset Fee is due to Ergon Energy calculating it based on the number of customers while Essential Energy calculated it based on the number of meters.

[75] Essential Energy, Attachment 8.7 – Charges for Type 5 and 6 metering services – 2014, Recoverable Costs Summary sheet

9. Summary and conclusion

Ergon Energy's proposed ACS default metering charges have been developed in response to the AER's re-classification of Type 5-6 metering services from SCS to ACS in its F&A paper for Queensland DNSPs.

The ACS default metering tariff categories have been developed on an efficient basis to avoid unnecessary transaction costs in accordance with the NER.

The ACS default metering prices for the 2015-20 regulatory control period were developed using a limited building blocks approach and are cost reflective in that they are based on the forward looking metering capital and operating costs of providing metering services.

A customer transfer (exit) fee has been proposed for customers who transfer to an alternative metering provider if competition is introduced into Type 5-6 metering services. This approach is consistent with the COAG Energy Council's rule change proposal and the recent regulatory proposals submitted by the NSW DNSPs.

10. Compliance and supporting documentation

10.1 Compliance

Ergon Energy's ACS Default metering prices have been developed on a cost reflective basis, based on the key drivers of providing the metering service for each category. The proposed approach is therefore in compliance with the following clauses of the NER:

- Clause 6.18.3(d)(1) - Ergon Energy has developed tariff classes that group customers on an economically efficient basis in that they are based on the nature of the network connection.
- Clause 6.18.3(d)(2) - Ergon has developed metering tariff classes to avoid unnecessary transaction costs by limiting classes to materials categories.
- Clause 6.18.5(a) – The expected revenue to be recovered by each tariff category lies on or between the standalone and avoidable cost of serving those customers.

10.2 Supporting Documentation

The following documents and models were used to support the development of Ergon Energy's ACS Default Metering Pricing proposal for 2015-20:

1. 05.04.06 - Ergon Energy, *00255 Engineering Report Meter Replacement Program*, 8 September 2014

2. 05.04.05 - Ergon Energy, *Meter Configuration Management System Report*, February 2014

3. Ergon Energy, *Cost Allocation Method*

4. 0A.02.07 - Energeia, *ACS Metering Tariffs for 2015-20, Customer Council Working Group Meeting,* 18 June 2014

5. 0A.01.04 - Ergon Energy, *Informing Our Plans, Our Engagement Program,* October 2014

6. 05.04.04 - Ergon Energy, *Metering Vision and Strategy,* October 2014

7. 0A.02.01 - Huegin, *Ergon Energy Expenditure Benchmarking – Partial Productivity and Cost Driver Analysis and Comparisons,* October 2014, p3

8. 05.04.07 - Ergon Energy, Metering Post-Tax Revenue Model (PTRM)

9. 05.04.09 - Ergon Energy, ACS Meter Pricing Model.