30 April 2015

Revenue Capped Metering Services

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Approval and Document Control

VERSION	DATE	AUTHOR
1.0		

Glossary

Abbreviations	
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AMI	Advanced Metering Infrastructure
ACS	Alternative Control Services
COAG	Council of Australian Governments
CROIC	Cost Recovery Order-in-Council
IT	Information Technology
NER	National Electricity Rules
NERR	National Energy Retail Rules
NMS	Meter Network Management System
RIN	Regulatory Information Notice
SCS	Standard Control Services
WPI	Wage Price Index

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1. Introduction

1.1. Purpose

This document explains our revenue requirements for the provision of revenue capped metering services for the forthcoming regulatory period. It explains our forecasting methodology and demonstrates that our forecasts comply with the Rules requirements. We also address the Regulatory Information Notice (RIN) requirements for revenue capped metering services.

1.2. Regulatory Information Notice Requirements

Schedule 1 RIN requirements in relation to metering services are reproduced below:

14. METERING ALTERNATIVE CONTROL SERVICES

14.1 For meter types 5 and 6 and *smart meters*, for the *current regulatory control period* and forecast for the *forthcoming regulatory control period*, provide details of the:

(a) *Direct materials* and *direct labour costs*;

(b) Installation costs;

(c) Meter purchase costs;

(d) Volumes of work;

(e) Other costs associated with providing metering services;

(f) Type of meters installed and forecast to be installed, separately for new meters and for replacement meters;

(g) The volume of meters by type set out in (f) and the revenue earned and forecast to be earned by each meter type; and

(h) The total operating and *maintenance* costs incurred, and forecast to be incurred, for metering services.

14.2 For metering works, for each year of the *current regulatory control period* and forecasts for the *forthcoming regulatory control period,* provide a description of:

(a) The type of work undertaken (e.g. *meter reconfiguration*, *special meter read*) including a description of the activities undertaken to provide the service;

(b) The *labour costs* involved in providing the service, including any *overheads*;

(c) Any materials costs involved in providing the service;

(d) The number (volume) of services provided and associated assumptions on which the volume of service was derived or estimated;

(e) The charge per service; and

(f) The revenue earned by each service.

In relation to the provisions in paragraph 14.2 of the RIN, we interpret this information as relating to fee-based metering services rather than revenue capped metering services. We have addressed these provisions in the supporting document, 'Fee-based and quoted ACS', and the costs of providing these services are excluded from the revenue capped metering services discussed in this document.

This document, therefore, addresses the RIN requirements set out in paragraph 14.1 in relation to the forthcoming regulatory period, which we interpret as relating to revenue capped metering services. The data is provided for the different meter types where it is practical to do so in the reset RIN template 4.2. In relation to actual data for the remainder of the current period, we have previously provided this information to the AER in the CA RINs. For completeness, this information is resubmitted in the AMI charges model that accompanies this Revenue Proposal, although most of the period relates to the AMI rollout program and therefore is of limited relevance to the forecast period.

We note that paragraph 19.1 of Appendix E of the RIN requires that the data provided for metering services reconciles to internal planning models used in generating United Energy's proposed revenue requirements. We confirm that the information presented is consistent with our internal planning models. A spreadsheet model, 'AMI EDPR Modelling', sets out the building block calculating for AMI metering charges, and is provided as part of this Regulatory Proposal. In this building block calculation, it should be noted that:

- The cost of capital, debt raising and corporate income tax components are consistent with the approach adopted for Standard Control Services; and
- The regulatory asset base and depreciation components are consistent with the approach adopted in the AMI charges model previously submitted to the AER in accordance with the CROIC.

For further information on these aspects of the building block calculation please refer to chapters 13 and 14 of the Regulatory Proposal and the 'AMI EDPR Modelling' spreadsheet.

1.3. Structure of this document

This document is structured as follows:

- Section 2 explains the background and key assumptions that underpin our forecasts for revenue capped metering services. In particular, we discuss the uncertainty regarding the national arrangements for introducing metering competition and its implications for revenue capped metering services.
- Section 3 presents our methodology and forecasts for operating expenditure
- Section 4 presents our methodology and forecasts for capital expenditure.
- Section 5 sets out our indicative meter charges for the forthcoming regulatory period.
- Appendix 1 provides further details of the forecast volumes, unit costs and other information underpinning the capital expenditure forecasts.
- Appendix 2 sets out our suggested application of the AER's revenue cap formula.

2. Background and key assumptions

2.1. Metering competition

In October 2013, the COAG Energy Council proposed changes to the National Electricity Rules (NER) and the National Energy Retail Rules (NERR) to introduce a competitive market for the provision of metering and related services. The scope of the proposed changes is briefly summarised below:

- Create a new 'Metering Coordinator' role with responsibility for providing metering and related services.
- Determine what additional accreditations might be required, if any, for the Metering Coordinator role.
- Establish last resort arrangements in cases where the Metering Coordinator fails.
- Establish the minimum functionality requirements and performance levels for smart metering infrastructure.
- Include provisions for jurisdictions to determine their own new/replacement and reversion policies.
- Revise the current arrangements regarding the provision of electronic data transfer facilities to a metering installation to support competition in the deployment of meters with advanced functionality.
- Establish appropriate implementation and transitional arrangements, including for Victoria where smart meters are already in place.

The AEMC's draft determination[1] in response to COAG Energy Council's rule change request was published on 26 March 2015, and the final determination is expected in July 2015. The draft rule contains a commencement date of 1 July 2017 for the new Chapter 7 of the NER and amendments to the NERR. The draft rule also proposes alignment for the end of the Victorian derogation and the commencement of metering competition, which would have the effect of extending the Victorian derogation for a period of 6 months.

United Energy notes that the outcome of the metering competition and related services rule change is a raft of procedure changes, and new accreditation and registration requirements. This is a considerable quantity of work with all new procedures or updated procedures being required to be finalised by 1 April 2016 and the new accreditation and registration requirements being available by 1 October 2016 in order to allow industry time to implement systems and processes.

It is noted that in the lead-up to the publication of the draft determination, the AEMC's consultation process identified a number of issues including:

- Whether there is a need for light handed regulation of access to Metering Coordinator services;
- Remote provision of disconnection and reconnection services;
- Network security issues due to direct load control;
- Opt out provisions for consumers;
- Timeframes and requirements for implementation; and

[1] AEMC, Expanding competition in metering and related services, Draft Rule Determination, 26 March 2015.

- The minimum services specification.

While most of these matters are addressed in the draft determination, uncertainty remains as to the final arrangements. A further complication for Victoria is that no date has been set for the commencement of NECF and the customer protections that are an integral part of that package. As these arrangements are not yet settled, a number of important uncertainties arise that may affect the costs of providing standard control services and revenue capped metering services. It is not necessary to provide an exhaustive list of these matters, but they include:

- The costs of systems and process changes to facilitate metering competition.
- The nature and scope of our future obligations.
- The extent of meter churn.

As noted in Chapter 18 of the Regulatory Proposal, the AER's Framework and Approach paper does not contemplate any pass through provisions to allow distributors to recover the actual costs of implementing the national framework for competition in metering and related services. The AER may wish to reconsider whether a pass through provision would be appropriate.

2.2. Key assumptions

In preparing our responses to paragraph 14.1 of Schedule 1 of the RIN, and in forecasting our revenue requirements for revenue capped metering services, we have assumed that:

- Metering competition will start on 1 July 2017. This assumption is consistent with the date proposed in the AEMC's draft determination published on 26 March 2015.
- New meters installed on a regulated basis during the forthcoming regulatory period will be remunerated through the revenue cap.

In relation to meter volume forecasts, we have made the following assumptions:

- Any existing United Energy meters will be replaced on a regulated basis if that meter becomes faulty.
- There are no AMI meter family failures in the forthcoming regulatory period and approximately 400 non AMI family failures in 2016.
- An estimated 1% of meters will be subject to churn.
- Approximately 10,000 meters per annum for new connections will be provided on a competitive basis from 1 July 2017.
- Approximately 2,500 meters per annum will be replaced due to additions or alterations, these will be provided competitively from 1 July 2017.
- A portion of remaining type 5/6 meters will be exchanged with an AMI meter based on customer move in/outs, approximately 4,000 in 2016 and 1,500 in 2017 prior to competition commencing.

Each of these volume assumptions is discussed in further detail below.

2.2.1. Meter Faults

We propose to replace our regulated meters if there is a fault, either following a high voltage injection or if the communications card is faulty and results in no supply or no/unreliable communications. Our view is that the distributor, as the Responsible Person, should rectify the metering installation. This approach will minimise the impact on customers, retailers and market settlements. We do not support leaving customers off supply or leaving customers with bridged wiring and unmetered supply while alternative metering arrangements are sought.

Our forecast of meter volumes for revenue capped metering services therefore includes an allowance for replacing faulty meters.

2.2.2. Meter Family Failures – Smart meters

If a meter family failure were to occur, it could present an opportunity for transition to the bulk provision of meters on a competitive basis. In our view, however, it is extremely unlikely that a family failure of AMI meters will occur in Victoria during the forthcoming regulatory period. In particular, the metering asset base is relatively new (earliest installations made in late 2009) with a minimum 15 year design life. We have therefore assumed no meter churn as a result of meter family failures.

2.2.3. Meter Churn

We consider it unlikely that there will be widespread retailer roll out of meters in Victoria during the 2016-2020 regulatory period. Retail churn in Victoria has been of the order of 25% to 30% per year. It is reasonable to expect meter churn to be smaller than retail churn.

We note that AEMO's recent meter churn package consultation found that fewer than 10 meters churned from a regulated metering service to an unregulated metering service across the NEM per week[2]. This data suggests that customers are slow to take up new offers. This conclusion is further supported by customers' low take up of the uniform time varying tariff in Victoria, even though (unlike meter churn) there is no disruption to supply.

While estimates are challenging, we have assumed that 1% of the meter population will churn per annum.

2.2.4. New Connections

We assume that meters for all new connections, numbering approximately 10,000 meters per annum, will be provided on a competitive basis from 1 July 2017. This volume of meters will be provided by contestable metering arrangements after 1 July 2017. This is consistent with the AER's position that all new metering installations will be supplied under the competitive framework.[3]

2.2.5. Additions & Alterations

We assume that all customer/retailer requested additions and alterations where a meter exchange is required will be provided on a contestable basis from 1 July 2017. This is consistent with the AER's position that any replacement meter of an existing meter will be supplied under the competitive framework (except where the meter is supplied as a restoration service).[4]

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[2] AEMO, Draft Determination Participant Response Pack, Meter Churn Package, General Feedback, page 6.

[3] Final Framework and Approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016, 24 Oct 2014, page 34.

[4] Ibid.

2.2.6. Non AMI meters existing as at 31 December 2015

At the end of 2015 we are expecting around 21,000 customers will continue to be supplied using non-AMI meters, being manually read type 5 meters and type 6 meters. As noted in the AMI CROIC, each Victorian distributor has a continued roll out obligation if there is a reasonable opportunity to exchange an old meter with a Victorian AMI meter. We have estimated 4,000 AMI replacements in year 2016 and 1,500 in year 2017 as part of Customer move in/out, and further 400 non AMI family failures in year 2016.

3. Forecast operating expenditure

3.1. Forecasting methodology

Our Expenditure Forecasting Methodology, dated 30 May 2014, explained that we adopt a base-step-trend approach to forecasting operating expenditure. This forecasting method involves:

1. Nominating the efficient base year.
2. Adjusting the base year to reflect recurrent costs.
3. Applying rate of change adjustments to the efficient base year to reflect the impact of:
   a. Labour and non-labour price escalation;
   b. Output growth; and
   c. Productivity.
4. Applying step changes to reflect changes in regulatory obligations or scope of work.
5. Add debt raising costs.

Chapter 11 of the Regulatory Proposal explained the application of this methodology to standard control services. The rationale for this forecasting approach is equally applicable to revenue capped metering services. The remainder of this chapter explains our operating expenditure forecast in terms of the five steps noted above.

3.2. Efficient Base Year Opex

To ensure consistency with the approach adopted for Standard Control Services, we have adopted 2014 as our base year for revenue capped metering services. It is worth recalling that United Energy faces a strong financial incentive under the CROIC to minimise its operating expenditure and not exceed the annual budget set by the AER in its 2012-2015 AMI determination[5]. As a consequence, the AER should have confidence that the actual operating expenditure incurred reflects the efficient costs of providing AMI services.

A relevant issue is whether the operating expenditure incurred in 2014 is representative of United Energy's requirements in the forthcoming regulatory period. This issue was examined in detail by the AER in setting the 2012-2015 budget, noting that the AMI rollout program was expected to be complete by 31 December 2013. The AER made the following observations[6]:

> "The DNSPs generally assert that ongoing operating expenditure levels will be higher following the AMI roll-out. CitiPower and Powercor suggest there is a residual business-as-usual component that is invariant to capital expenditure at the conclusion of the AMI roll-out. Similarly, JEN states:
>
> > *Such an extensive IT and communications infrastructure requires constant maintenance and operational management to ensure that 100 per cent of meters are serviceable as remote AMI meters. As such, AMI doubles the number of connections managed by the distribution business (Electrical and Communications) and significantly increases the overall operational costs.*"

In light of advice from its consultants, Energeia and Impaq Consulting, the AER reached the following conclusions[7]:

5 AER, Victorian Advanced Metering Infrastructure Review 2012–15 budget and charges applications, October 2011.

6 Ibid, page 12.

7 Ibid.

"On balance, the AER accepts it is plausible that there will be a 'step up' in the DNSPs' ongoing operating expenditure after the completion of the major part of the AMI rollout. This is reflected in the AER's assessment of the individual expenditure items proposed by the DNSPs in this determination. The AER acknowledges that the Cost Recovery Order reflects that the AMI roll-out requires investment in new technology, which introduces new and additional metering obligations for the businesses. This is likely to mean a new and different operating metering environment for the DNSPs as compared to the pre-AMI period."

Our actual operating expenditure for 2014 was $23.47 million compared to the AER's budget of $22.92 million, both expressed in nominal terms. As the rollout program was more than 96 per cent complete by 31 December 2014, this outcome illustrates that:

- The AER's conclusions regarding the post-AMI operating expenditure were correct, and no operating expenditure savings arise as a result of completing the rollout program.
- Our actual operating expenditure for 2014 is representative of our recurrent costs.
- The AER's budget was only 2.4% lower than our actual costs, which reinforces the conclusion that our expenditure is efficient notwithstanding the strong commercial incentives for us to minimise expenditure.

Table 1 sets out our base year operating expenditure for the forthcoming regulatory period, which is our actual operating expenditure for 2014 expressed in 2015 prices.

Table 1: Base Year Opex – Revenue Capped Metering Services ($M real 2015)

	2016	2017	2018	2019	2020	TOTAL
Base Year Opex	24.01	24.01	24.01	24.01	24.01	**120.1**

3.3. Adjusted Base Year Opex

Our current meter charges are regulated by the AER in accordance with a Cost Recovery Order-in-Council (CROIC) issued by the Victorian Government. These arrangements continue until 31 December 2015, after which date these services are subject to economic regulation in accordance with the Rules.

To determine an appropriate base year costs for revenue capped metering services for the forthcoming regulatory period, adjustments are required to reflect the AER's service definition. In particular, the AER's Framework and Approach Paper defines revenue capped metering services as[8]:

"Installation, operation, repair & maintenance, and replacement of type 5-6 metering installations (including smart meters)"

The AER's definition is substantially narrower than the scope of regulated metering services in the CROIC. The following excerpt from Part 1, Schedule S2.1 illustrates the broad nature of the CROIC:

"Activities reasonably required for the provision, during the initial regulatory period, of the metering services referred to in paragraph (b) of the definition of Regulated Services including:

[8] AER, Framework and Approach, Appendix B, Classification of Services, 24 October 2014, page 98.

(i) procurement, installation, operation and maintenance of AMI Technology to support the billing of network tariffs;

(ii) provision of metering data services, including remote meter reading, meter data processing, meter data management, data provision to NEMMCO and market participants;

(iii) operation and maintenance of AMI Technology, including asset management plans, asset register, inspection, testing, fault rectification, optimisation and augmentation;

(iv) establishment and ongoing maintenance of data required by the National Electricity Rules;

(v) customer service and

(A) management of guaranteed service level payments;

(B) management of complaints and enquiries;

(C) management of and meeting claims;

(D) management and responsibility arising from Ombudsman complaints;

(E) call centre;

(F) customer communications and notifications; and

(G) focus groups, surveys, retailer communications and process audits;

(vi) establishment, operation, maintenance and enhancement of information technology applications, systems and infrastructure, including those listed in the Annexure and disaster recovery; and

(vii) executive and corporate office services."

For completeness, it is also worth noting the services in the CROIC that were defined as 'outside scope'. This highlights that CROIC services only excluded those network functions that were deep within the distribution network:

"Activities outside scope include:

(i) subject to clause S2.6(b)(2)(vii)(E), provision, operation and maintenance of Distribution IT Systems, including disaster recovery;

(ii) subject to clause S2.6(b)(2)(vii)(E), provision, installation, repairs, maintenance or replacement of distribution system assets, including service cables;

(iii) the extension of the use of AMI Technology for electricity network control or operation purposes including:

(A) distribution transformer monitoring;

(B) operation of line switches; and

(C) monitoring of line fault detectors;

(iv) using AMI Technology to provide communications services beyond those in the most up to date Specifications."

As the AER's Framework and Approach paper defines the revenue capped metering services more narrowly than the CROIC, an adjustment to the base year operating expenditure must be made to ensure consistency with the AER's definition. Specifically, revenue capped metering services should not include costs that are incurred in providing standard control services (SCS). For example, costs associated with maintaining and operating the billing systems, B2B systems and Customer Information Systems are core functions of a distribution business. It is appropriate that these costs are allocated to standard control services, and are removed from the base year operating expenditure that was previously attributable to regulated services in accordance with the CROIC.

To ensure that the base year opex for revenue capped metering services reflects the recurrent costs of operation, repair and maintenance of type 5, type 6 and smart meters, we have adopted the following allocation approach:

- Direct costs associated with operation, repair and maintenance of type 5-6 metering installations (including smart meters) are allocated to revenue capped metering services.
- Where activities are shared, the costs of delivering the distribution network services are allocated to SCS. Any incremental costs in providing revenue capped metering services are allocated to that activity.

The alternative approach of simply 'rolling forward' the CROIC definition of operating expenditure would not be appropriate. In particular, this approach would create an inconsistency between the AER's service classification and the building block costs, with the consequence that revenues and prices would be:

- Higher than their efficient level for revenue capped metering services; and
- Lower than their efficient level for standard control services.

Both outcomes would be contrary to the National Electricity Objective (NEO), which is focused on promoting efficient investment and consumption decisions for the long term benefit of consumers. From an efficiency perspective, the revenues caps for SCS and ACS should reflect the costs of providing the relevant services, without any cross-subsidy between the two service categories. This approach will promote economic efficiency (and the NEO) by providing cost reflective price signals to consumers and producers, consistent with the AEMC's recent initiatives in relation to network tariff design.

As already explained, we are adopting the same base year, being 2014, for both standard control services and revenue capped metering services. The proposed adjustment between SCS and revenue capped metering services will not affect our total operating expenditure. However, the adjustment will promote efficient pricing and competition in provision of metering services, consistent with the National Electricity Objective, for the reasons set out above.

The table below shows the adjustments to base year opex for each year of the next regulatory period.

Adjustment 1 – IT Support Costs

As noted above, the scope of the CROIC includes metering services and the provision, operation and maintenance of IT systems to manage the rollout, operate AMI technology and to process the data and meet our service obligations. These systems include not only the metering systems but, in United Energy's case, the provision of new connection point and standing data systems and network revenue management systems to cater for the increased volumes of metering data. For the reasons already outlined, the operational IT support costs of revenue management and connection point/standing data management should be transferred to SCS. The relevant IT operating expenditure is $12.84 million.

Adjustment 2 – Back Office Costs

In relation to back office costs, the 2014 base year will be adjusted by $5.36 million, to reflect the business as usual costs as a consequence of the smart meter roll out. It reflects the costs of addressing retailer queries and managing the complexity of new connections. Each of these are discussed briefly below:

- Retailer queries:

  United Energy has over 96% smart meters collecting data by 6am each day, which has resulted in changes to the volumes of data, the frequency of network billing and the level of retailer queries to service desk in relation to billing. The transfer includes the costs of calls that relate to the provision of Standard Control Services.

- Managing new connections:

  During the smart meter roll out a portion of the new connection team's costs were allocated to the CROIC to manage the increased complexity of new connections and the type of meter that needed to be deployed depending on the mesh coverage and mesh robustness at each connection. Increased levels of solar connection and meter exchanges also arose due to favourable policy initiatives over the period. The need to exchange meters and provide bi-directional net metering also required higher levels of analysis of the mesh coverage. This team needs to manage this ongoing complexity as a business as usual activity to meet the NSP obligations to manage the network connections activities in a timely and safe manner. This complexity will be exacerbated after metering competition commences, as the activities associated with new connections are separated from meter provision and need to be coordinated across multiple parties.

Adjustment 3 – AMI NOC

The AMI NOC team undertakes the management and provision of services to operate and maintain the AMI communication system to meet the required service levels. This includes internal management, field communications and meter investigations, maintenance and support and testing. During the forthcoming regulatory period, the AMI communications network will support improved outage management and fault restoration, and enhanced network load management to enable improved network planning and maintenance analysis. Services will also be targeted to achieve improved network utilisation and demand response, to better manage network capacity at times of network constraint.

Staffing costs will support both metering services and network services, and this will extend to testing support, trouble shooting issues, management of data security and public communication costs as a consequence of delivering improved real time management of the United Energy distribution network.

The AMI NOC team provides support to ensure that meter reading and remote de-energisation and re-energisation transactions are managed in line with the regulatory requirements. Data and processes managed by the AMI NOC team facilitate more precise and timely identification of network issues compared to relying on customer calls, in addition to monitoring power quality. United Energy has allocated $0.68m of the NOC team's costs to support of distribution services. The table below sets out the unadjusted base year opex, the three adjustments noted above, and the adjusted base year opex for the forthcoming regulatory period.

Table 2: Efficient Base Year Adjustments – Revenue Capped Metering Services ($M real 2015)

	2016	2017	2018	2019	2020	TOTAL
Unadjusted Base Year Opex	24.01	24.01	24.01	24.01	24.01	120.07
Adjustment 1 - IT Support (SCS)	12.84	12.84	12.84	12.84	12.84	64.20
Adjustment 2 - Back Office (SCS)	5.36	5.36	5.36	5.36	5.36	26.8
Adjustment 3 - AMI NOC support	0.68	0.68	0.68	0.68	0.68	3.4
Total adjustments	18.88	18.88	18.88	18.88	18.88	94.40
Adjusted Base Year Opex	5.13	5.13	5.13	5.13	5.13	25.66

3.4. Rate of change

As already noted, the rate of change comprises three elements:

- Labour and non-labour price escalation;

- Output growth; and
- Productivity.

In relation to labour and non-labour prices, it is appropriate to adopt the same approach to revenue capped metering services as adopted in relation to standard control services. In particular, as noted in Chapter 11 of the regulatory proposal, BIS Shrapnel were engaged to develop labour rate forecasts for the forthcoming regulatory period using:

- A bottom-up approach for industry sectors at a regional and individual category level; and
- A top-down model based on prevailing trends, investment and business cycles and assumptions about the general macroeconomic outlook.

BIS Shrapnel's forecast of growth in the Wage Price Index (WPI) is detailed in the table below.

Table 3: Real rate of change – labour price (WPI) – Revenue Capped Metering Services (per cent)

		2016	2017	2018	2019	2020	Average
Labour	Electricity, Gas, Water and Waste Services	0.9	1.3	1.8	2.1	1.8	1.6
	Contractor	1.2	1.6	1.5	1.6	1.9	1.6

Source – BIS Shrapnel, "Real Labour and Material Cost Escalation Forecasts to 2020 – Australia and Victoria, Final Report", Nov. 2014, page ii

We applied the BIS Shrapnel labour cost escalators to our mix of employees and contractors for standard control services. The table below shows our forecast opex increase attributable to real labour price growth in the next regulatory period.

Table 4: Labour cost escalation – Revenue Capped Metering Services ($ '000 Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Labour cost escalation	29	41	57	67	57	**251**

In contrast to standard control services, the output changes for revenue capped metering services are not expected to have a material effect on our operating expenditure in the forthcoming regulatory period. As noted in our volume forecasts, we expect relatively modest changes over the forthcoming regulatory period. We have therefore adopted a value of zero for output changes.

A productivity change of zero has also been adopted.

3.5. Step changes

We are not proposing any step changes in relation to operating expenditure for revenue capped metering services.

3.6. Debt raising costs

Debt raising costs have been estimated on a consistent basis with section 13.6 of the Regulatory Proposal. Further details of the calculation are provided in the 'AMI EDPR Modelling' spreadsheet.

3.7. Forecast operating expenditure

Based on the information set out in sections 3.2 to 3.7, the table below shows our operating expenditure forecast for revenue capped metering services.

Table 5: Opex forecasts for Revenue Capped Metering Services ($M Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Unadjusted Base year Opex	24.01	24.01	24.01	24.01	24.01	120.07
Base Year Adjustments	(18.88)	(18.88)	(18.88)	(18.88)	(18.88)	(94.41)
Output Growth	0	0	0	0	0	0
Labour cost escalation	0.03	0.04	0.06	0.07	0.06	0.25
Productivity Growth	0	0	0	0	0	0
Step Changes	0	0	0	0	0	0
Debt raising	0.25	0.22	0.19	0.16	0.15	1.0
Total	5.4	5.4	5.4	5.4	5.3	26.9

3.8. Transition Charges

Clause 5L of the CROIC provides for a true-up for actual costs and revenue in relation to 2014 and 2015, as we transition from the cost recovery regulation provided by the CROIC to regulation under the NER. This transition charge will be reflected in our metering charges for 2016 and 2017.

In accordance with clause 5L.3, United Energy will be submitting a 2016 Transition Charge Application to the AER no later than 31 August 2015. At this stage, we have included a $2.5 million revenue adjustment in our proposed metering charge for 2016 to reflect the actual AMI revenue shortfall from 2014 compared to the AER's allowed revenue. As already noted, the proposed adjustment is consistent with the CROIC provision and the unwinding mechanism from a cost pass through regulatory framework to a revenue cap framework under the NER.

4. Forecast capital expenditure

4.1. Forecasting methodology

The capital expenditure for revenue capped metering services include:

- Meter purchase for:
  - New connections;
  - Customer initiated meter replacements; and
  - Fault meter replacements.
- Information technology systems which process and store the metering data; and
- Communications infrastructure (control systems) which enables data to be transmitted to and from the meters including the mesh radio network and the Meter Network Management System (NMS).

As explained in the Forecasting Methodology submitted to the AER in May 2014, we forecast our capital expenditure requirements using a bottom up approach, which applies the following steps:

Step 1 United Energy prepares volume forecasts using the following key techniques:

(i) Technique 1 – Customer growth forecasts and life cycle replacement

Determine investment requirements based on our net customer growth forecasts and AMI life cycle replacement plans, which are informed by historic fault rates and customer initiated replacements.

This technique is used for meter purchase.

(ii) Technique 2 – Based on life cycle refresh programs

Determine investment requirements based on the life cycle refresh programs, which are required for ongoing vendor support and periodic patch releases to identify defects or potential security exposures. The life cycle refresh programs have been developed having regard for the age of the technology and the cost of upgrade versus replacement.

This technique is used for information technology systems and communications infrastructure.

Step 2 Identify unit costs based on recent actual costs

Step 3 Test and validate investment volumes and unit costs derived in steps 1 and 2 where appropriate through market testing.

Step 4 Determine expenditure by multiplying volumes in step 1 by unit costs in step 2 making any adjustments identified in step 3.

4.2. Forecast capital expenditure

Our capital expenditure forecast is made up of the following elements:

- Meter purchase costs;
- Meter installation costs;
- Information technology (IT) infrastructure; and
- Communications infrastructure.

The table below provides an overview of our capital expenditure forecast by each of these 4 elements, for the forthcoming regulatory period.

Table 6: Revenue capped metering services capital expenditure forecast ($M Real 15)

	2016	2017	2018	2019	2020	Total
Meter purchases	0.809	0.000	0.000	0.000	0.000	**0.809**
Meter installation	2.154	1.066	0.630	0.657	0.675	**5.812**
IT infrastructure	7.404	4.942	0.478	0.820	2.848	**16.493**
Comms infrastructure	0.144	0.072	0.000	0.000	0.000	**0.216**
Total	**10.512**	**6.080**	**1.109**	**1.478**	**3.523**	**22.701**

Appendix 1 provides further details of the forecast volumes, unit costs and other information underpinning the capital expenditure forecasts.

5. Indicative meter charges

The following table shows our indicative meter charges for the forthcoming regulatory period, given our revenue requirements and meter volumes. Our actual meter charges will be determined by the operation of the revenue cap formula set out in Appendix 2.

Table 7: Indicative meter charges ($ per meter Real 15)

	2016	2017	2018	2019	2020
Single phase single element meter	55.92	55.92	55.92	55.92	55.92
Single phase single element meter with a contactor[9]	55.92	55.92	55.92	55.92	55.92
Three phase direct connected meter	63.06	63.06	63.06	63.06	63.06
Three phase current transformer connected meter	66.81	66.81	66.81	66.81	66.81

[9] This charge is applicable for single phase, single element meters with a contactor and also single phase, two element with contactor once this metering configuration is available

Appendix 1: Detailed information underpinning capital expenditure forecasts

1. Meter purchase costs

We have analysed our meter purchase requirements by estimating the following volumes of new AMI meters that will be required, taking into account:

- New connections
- AMI meter exchanges
- Faults
- Returned meter volumes, as a result of competition and abolishments
- Current and estimated stock.

In terms of unit costs, it is noted that the volume discount we obtained as part of the AMI rollout program is not available for the smaller volume in the forthcoming regulatory period. Our forecast unit costs set out in the table below reflect a 10% increase compared to the AMI rollout, which reflects the loss of the AMI volume discount, and a further 10% increase as advised by the meter manufacturer. Our assumed exchange rate is 1 AUD= 0.7 USD.

As a result of our volume analysis, we conclude that only a relatively modest number of meter purchases is required in 2016, with no additional purchase requirements in later years. The table below shows the forecast meter purchase volumes, unit rates and total meter purchase costs for 2016.

Table 8: Forecast meter purchase volume and expenditure for 2016 (Real 15)

	Unit Rate	Volume	Cost $m
Single phase single element	$235	0	0
Single phase single element with contactor	$264	0	0
Single phase two element with contactor	$306	0	0
Three phase direct connected meter	$396	1800	0.713
Three phase direct connected meter with contactor	$436	0	0
Three phase Current transformer connected meter	$481	200	0.096
Total		**2000**	**0.809**

The volume forecasts set out above assume that competition commences in July 2017.

The tables below provide the forecast components that have led to the meter purchase requirements set out above. This detailed information provides assurance to the AER that the forecast meter purchase volumes have been carefully considered. The tables also address the information requirements in clause 14.1(d) of schedule 1 of the AER's RIN requirements, which require us to detail the volume of work to be undertaken.

Table 9: New connection volume forecasts

	2016	2017	2018	2019	2020
Single phase single element	7,367	3,684	0	0	0
Single phase single element with contactor	71	36	0	0	0
Single phase two element with contactor	240	120	0	0	0
Three phase direct connected meter	2,088	1,044	0	0	0
Three phase direct connected meter with contactor	70	35	0	0	0
Three phase Current transformer connected meter	164	82	0	0	0
Total	**10,000**	**5000**	**0**	**0**	**0**

Table 10: AMI meter exchange volume forecasts

	2016	2017	2018	2019	2020
Single phase single element	1,976	674	0	0	0
Single phase single element with contactor	221	76	0	0	0
Single phase two element with contactor	396	135	0	0	0
Three phase direct connected meter	1,533	523	0	0	0
Three phase direct connected meter with contactor	176	60	0	0	0
Three phase Current transformer connected meter	98	33	0	0	0
Total	4,400	1,500	**0**	**0**	**0**

Table 11: Faults volume forecasts

	2016	2017	2018	2019	2020
Single phase single element	1,196	1,244	1,294	1,345	1,399
Single phase single element with contactor	29	30	31	32	33
Single phase two element with contactor	126	131	136	142	148
Three phase direct connected meter	196	204	212	221	229
Three phase direct connected meter with contactor	5	5	6	6	6
Three phase Current transformer connected meter	53	56	59	62	65
Total	1,605	1,670	1,738	1,808	1,880

Table 12: Forecast returned meter volumes due to competition and abolishments

	2016	2017	2018	2019	2020
Single phase single element	2,456	3,946	5,438	5,438	5,438
Single phase single element with contactor	64	103	142	142	142
Single phase two element with contactor	283	455	627	627	627
Three phase direct connected meter	660	1,061	1,461	1,461	1,461
Three phase direct connected meter with contactor	12	19	26	26	26
Three phase Current transformer connected meter	25	41	56	56	56
Total	**3500**	5625	7750	7750	7750

Table 13 shows the net meter volume requirements for new connections, meter exchanges and faults, less the estimated volume of meters returned to stock due to competition and abolishments. It is noted that the volume requirements for 2016 are significantly higher than the proposed meter purchases presented in Table 8. This difference is explained by existing meter stock volumes, which will address most of the additional meter volume requirements in the forthcoming regulatory period.

Table 13: Forecast net meter volume requirements

	2016	2017	2018	2019	2020
Single phase single element	7,855	3,145	-2,653	-4,093	-4,040
Single phase single element with contactor	257	77	-73	-110	-109
Single phase two element with contactor	478	103	-319	-486	-480
Three phase direct connected meter	3,377	1,110	-849	-1,241	-1,232
Three phase direct connected meter with contactor	239	88	-14	-21	-20
Three phase Current transformer connected meter	297	146	18	6	9
Total	12,503	4,669	-3,890	-5,945	-5,872

2. Meter Installation costs

The table below shows the total volume of meter installations in each year of the forthcoming regulatory period.

Table 14: Forecast meter installation volumes

	2016	2017	2018	2019	2020
Single phase single element	12,175	6,419	1,293	1,345	1,398
Single phase single element with contactor and single phase two element with contactor	1,435	703	166	173	180
Three phase direct connected meter	4,554	2,114	217	225	235
Three phase Current transformer connected meter	339	184	59	62	65

The corresponding total cost of net meter installations is shown in the table below.

Table 15: Forecast meter installation costs ($'000 Real 2015)

	2016	2017	2018	2019	2020
Total Cost	2,154	1,066	629	657	674

Faults

The fault replacement costs include:

- The costs to install meters in fault conditions, based on resource costs to support a 24x7 operation and a 2 person fault crew/truck. The cost for meter faults are based on competitively let contract rates.
- Current Transformer connected meter fault replacement costs, based on specialist meter contract unit rates.

AMI exchanges

The Victorian Government amended the AMI roll out obligation in August 2014 following announcement of the policy changes in June 2014:

> 'DSDBI considers that it is appropriate that, after 30 June 2014, the ongoing obligation to install a smart meter should be defined having regard to efficient commercial practices – a smart meter should be installed at new premises and where a meter is to be replaced. In relation to existing premises which do not have a smart meter, while distributors should not be absolved from their obligation to install a smart meter at these sites, they should only be required to install a smart meter where it is efficient to do so. As such, a smart meter should be installed at the first reasonable opportunity following the reason for non-installation being removed.
>
> The draft Order in Council released in conjunction with the draft position paper stipulated that the new installation obligation for distributors would apply from 1 November 2014. The Government's final position, as reflected in the Order in Council, has been modified to ensure that the obligation will apply from the

> commencement of the amending order, which is anticipated to be at the beginning of August 2014. The modification of this position reflects that the mandated rollout of smart meters was completed on 30 June 2014 and distributors have now returned to 'business as usual' metering installation.' [10]

The final policy decisions were:

> 'From the date of the commencement of the amending Order, a distributor must install a smart meter:
>
> - at all new premises/connection points;
> - when replacing a meter that is not a smart meter as part of the ordinary meter replacement cycle as a result of fault with the meter;
> - at the first reasonable opportunity after any inability to install, inability to access or account holder refusal is resolved.'[11]

The continued roll out obligation to sites where customers may have technical or other defects, the customer may have refused or not provided access means that the majority of these sites will not be a simple exchange unless the customer is now choosing to grant access and there are no other site issues. The expectation is that a meter exchange would also occur when a distributor field officer is required to attend premises to de-energise or otherwise conduct work. This means that there is an increased level of back office work to link the de-energisation or move out processes for non AMI sites to maximise the opportunity to exchange an old meter for an AMI meter.

Customers may also seek to upgrade to an AMI meter in order to access better data or tariff offerings. Customers may request AMI meters and hence there is an increased level of engagement to ensure that the original refusal reason has been managed and the meter exchange occurs at a time when access can be granted. These may be appointment based meter exchanges and will be scattered across the United Energy distribution area.

In addition to the customer interactions and appointments outlined above, there will also be site consideration to ensure that there is sufficient mesh strength to ensure reliable remote access.

These additional AMI meter exchanges are based on a mix of specialist meter contracts with the addition of back office costs relating to customer management/requests and appointments and site studies for mesh communications viability.

These costs are based on competitive market pricing for meter installs and do not reflect the synergies of higher installation volumes and the travel time efficiencies previously enjoyed under the AMI rollout program. The last 1% of non AMI sites needs significantly more business as usual resource time than the project management for the 99% customers who have an AMI meter.

Non AMI family failures

In line with the policy above, United Energy has a continued AMI roll out obligation for new and replacement meters. United Energy has approximately 21,000 (at the start of 2016) non AMI meters and a NER obligation to continue to test and manage all meter families consistent with the Rule requirements and the approved Meter Asset Management Plan. United Energy forecast that up to 3 of the approximate 50 non –AMI meter families will fail and require replacement before metering competition commences. These meters are scattered across the entire United Energy area and will require a managed replacement program.

Non AMI meter family failures require a higher degree of customer communications as these customers may have refused an AMI meter or refused access on a number of occasions during the roll out or the customer may have

10 Victorian Government, AMI Program, Implementation of ongoing arrangements for the installation of smart meters – final position paper, 25 June 2014, p4.24
[11] Ibid p4.25

also refused or delayed the rectification of a previous defect or technical difficulty. The customer will be notified in writing of the necessary meter replacement and this written notification will include contact numbers to enable a customer to suggest more convenient timeframes. Increased level of back office and customer case management may be required to enable meter exchanges to proceed and ensure that any sites flagged as life support are appropriately managed. The costs also reflect a portion of metering installations where there may need to be an increased level of technical work at the site to enable a replacement meter to make replacement of the non-compliant meter possible. The technical work may include items such as second meters, load control contactor installation, customer side defects such as meter panel replacement. Where the process for replacement of meters has not been successful, engagement with AEMO will be required to seek formal exemptions for individual sites.

LV CT Family fails

The costs of LV CT replacement are based on more complex metering installations and higher installation costs. These sites are business customers and the replacement of LV CTs involves the negotiation and agreement of a site shut down that would usually be carried out after business hours. The costs include LV CTs, installation and the back office and customer engagement processes. It should be noted that three LV CTs are required to be replaced at each site and the replacement cost includes the purchase cost for the LV CTs.

3. Communication Capex

Capital costs relating to the augmentation of the AMI communications network will be required while United Energy is still providing the regulated metering services. These costs have been allocated to metering ACS ie costs in 2016 and the first half of 2017. Some additional communication equipment may be required to ensure reliable metering data in new developments and sub divisions during this period to augment the existing network.

Capital costs are based on 4 additional relays and 20 repeaters including hardware, installation and traffic management at a cost of $119.5k per year. An additional $24.5k is required for RF strategic network planning and implementation each year. These costs are 50% lower in 2017, on the assumption that metering competition commences on 1 July 2017.

New Meter installations, Faults, Adds&Alts, Meter Family failures and Mass Rollout will be contestable from 1 July 2017 and United Energy as the initial Metering Coordinator will not be allowed to install new or replacement meters at these sites. Loss of meters may require additional communication infrastructure after competition commences, these communications in fill costs are covered in exit fee.

4. IT infrastructure Capex

The majority of the IT capital allocated to metering ACS is related to the Power of Choice-Metering Competition and related services Rule change and the lifecycle refresh for the AMI head end systems which manages the remote data collection. These two projects comprise approximately 75% of the capital allocated to the metering ACS in the period 16-20. The remainder of the capital projects relate to normal regulatory and business changes, webMethods refresh and improved meter asset management systems.

The project costs associated with Power of Choice-Metering Competition and related services Rule change have been allocated 50% to metering ACS and SCS. The project will deliver systems and processes to provide the following capabilities:

- Expanding competition in metering and related services
- Framework for open access and common communication standards for smart meters.
- Support for metering to the national minimum standard.

This project required is to meet the following requirements:

- Establishment of the metering coordinator role and enable accreditation for this role.
- Provide support for meter and participant churn and associated market transactions.
- Enable and manage receipt of metering data and meter and datastream configuration from third parties for all meter types.
- Establish communications infrastructure and systems to enable open access to metering data and functions and the adoption of the Shared Market Protocol. This includes capabilities to access other metering coordinators' systems and provide access to United Energy's metering coordinator's system.
- Support transactions for retailer load control including appropriate network business approval process.
- Establish capability for real time metering transactions.
- Provide support for metering to the national minimum meter standard.

The project requires substantial changes to our systems to support new market roles and large volume data transfers between market participants. In addition the new capability to support real time market transactions has significant impacts on many of our systems. This project does not provide full system or business separation, which may be considered in any ring fencing requirements.

The AMI head end communication system, SSN UIQ is expected to require some upgrade or refresh during the next period as the level of transactional volumes and use of other services increases. 60% of the capital cost of the refresh has been allocated to meter ACS.

The forecast costs associated with these projects have been developed by Accenture under a direct contract with United Energy which was established following a competitive tendering process for IT application management services carried out in 2011-2012. The rates for system enhancement work were negotiated with Accenture as a continuation of that procurement process. The minor changes and improvements or IT project work depending on the size of the change will be managed in line with the IT change management policy and IT governance arrangements.

The expenditure is necessary to meet the changed Rule and Procedures as a consequence of the Power of Choice reforms and all expenditure is subject to governance controls in relation to levels, scope and pricing.

The table below details the allocation of each capital project to the metering ACS.

Table 16: Allocation of IT projects to Metering ACS

Project	Metering ACS Allocation	Estimated ACS Cost	Notes
Power of Choice - Metering Competition	50%	$8.2M	Introduction of the metering coordinator role and shared market protocol will require significant changes to both metering and SCS systems. This project does not provide for ring fencing of metering ACS and SCS systems.
Application Change Requests (Factory)	10%	$0.5M	Expected change requests related to metering only.
IT Infrastructure Refresh	10%	$0.7M	Estimate of total metering workload on IT systems.
Itron Refresh	10%	$0.4M	Itron is primarily an SCS system. Expected that some costs associated with refresh projects will be to support metering. Example refresh of Itron MTS.
Security Program (IT)	10%	$0.5M	Estimate of total metering workload on IT systems.
Infrastructure Refresh - Client Device Lifecycle	5%	$0.1M	Based on workstations used for metering functions. Most client devices are with service providers.
Infrastructure Refresh - Data Protection	10%	$0.2M	Estimate of total metering workload on IT systems.
Infrastructure Refresh - Reporting Platform	10%	$0.1M	Estimate of total metering workload on IT systems.
Infrastructure Refresh - Telephony	10%	$0.1M	Estimate of total metering workload on IT systems.
Small Applications Refresh Program	10%	$0.4M	Estimate of total metering workload on IT systems.
SSN UIQ Lifecycle Refresh	60%	$4.0M	Based on expected used of the SSN UIQ system over the 2016-2020 regulatory control period. Expect significant network management capability.
WebMethods Refresh	10%	$0.3M	Estimate of total metering workload on IT systems.
Meter Asset Management	100%	$0.8M	Metering only project.
Total		**$16.4M**	

UNITED ENERGY

Appendix 2: Proposed application of AER revenue cap formula

Preamble

The formula below explains how the term B_t in the AER's revenue cap formula may address the uncertainty regarding the timing and effectiveness of meter competition. Our proposed approach would provide a true-up mechanism to account for forecasting errors in the amount of meter churn and the start date for metering competition.

A price allowance is provided for each meter category, so that the revenue cap is adjusted to reflect differences between the forecast and actual number of meter installations in the forthcoming regulatory period. The price allowance is equal to the revenue capped meter charge for the relevant meter category. This approach ensures that the distributor retains an incentive to install meters at minimum efficient cost, but does not face the risk of windfall gains or losses as a result of forecast errors (which are beyond the distributor's control).

We also clarify that revenue from exit fees should not be treated as 'regulated revenue' for the purpose of the revenue cap. Instead, the exit fee revenue is addressed as follows:

- The capital component of exit fee revenue should be treated as a disposal and removed from the metering RAB for the next regulatory period (2021-2025).
- The operating cost element of the exit fee allows the distributor to recover the incremental costs of removing the meter. Both the costs and revenues should fall outside the revenue cap, thereby avoiding the need to forecast these costs in the building block calculation.

Our proposed application of the AER's formula is set out below.

Proposed formula

The revenue formula for type 5, 6 and smart metering - regulated service.

(1) $$MAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$$

i=1,...,n and j=1,...,m and t=1,..., 5

(2) $$MAR_t = AR_t + T_t + B_t$$

(3) $$AR_t = AR_{t-1}(1+CPI_t)(1- X_t)$$

Where:

MAR_t is the maximum allowable revenue in year t.

p_t^{ij} is the price of component i of tariff j in year t.

q_t^{ij} is the forecast quantity of component i of tariff j in year t.

AR_t is the annual revenue requirement for year t.

AR_{t-1} in 2016 is the annual smoothed revenue requirement in the Post Tax Revenue Model for the 2016 year in 2015 dollar value. After 2016 this is the AR_t from the previous year.

CPI_t is the percentage increase in the consumer price index. To be decided in the final decision.

X_t is the X-factor in real terms in year t, incorporating annual adjustments to the PTRM for the trailing cost of debt where necessary. To be decided in the final decision.

T_t is the adjustments in year t for true-ups relating to the AMI-OIC.

B_t is the sum of:

1. annual adjustment factors in year t for the overs and unders account,
2. the AER's determination of transition charges arising from the CROIC, and
3. an adjustment to account for the difference between the forecast volume of AMI meter installations adopted in calculating AR_t and the actual volume of AMI meters actually installed in year t, as per the formula below:

$$C_t = \sum_{i=1}^{m} (AV_t^i - FV_t^i) p_t^i$$

AV_t^i is the actual volume of meter category i installed in year t, excluding meters installed on a competitive basis.

FV_t^i is the forecast volume of meter category i assumed to be installed on a regulated basis in year t in setting the AR_t (being the annual revenue requirement for year t), as shown below:

Meter category	FV_t^i Forecast meter installations in setting revenue cap				
Year t	**2016**	**2017**	**2018**	**2019**	**2020**
Single phase single element meter	12,175	6,419	1,293	1,345	1,398
Single phase single element meter with a contactor	1,435	703	166	173	180
Three phase direct connected meter	4,554	2,114	217	225	235
Three phase current transformer connected meter	339	184	59	62	65

p_t^i is the AER's approved meter charge for meter category i in year t[12].

[12] Indicative prices for revenue capped metering charges are set out in Chapter 5 of this paper.