CitiPower
Revised Regulatory Proposal
2016–2020

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Executive summary 1

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1 Executive summary

We recognise the Australian Energy Regulator's (**AER's**) preliminary determination of October 2015 has accepted many elements of our regulatory proposal and has seen merit in the majority of our investment priorities.

We welcome the opportunity to respond to the AER's preliminary determination in this revised regulatory proposal.

This chapter outlines our response to the preliminary determination. This chapter does not attempt to provide an exhaustive list of the ways in which our revised regulatory proposal endorses or departs from the AER's preliminary determination. Rather, we focus on our key concerns about the AER's approach and the decisions or conclusions in its preliminary determination with which we take issue in this revised regulatory proposal.

Our key concerns include:

- the calculation of the rate of return being inconsistent with rate of return objective and the benchmark efficient firm with a similar degree of risk;
- the value of gamma continuing to be set at 0.4 despite evidence supporting 0.25;
- the use of the Electricity Gas Water and Waste Services wage price index to set forecast labour escalation despite the business being required under the Fair Work Act 2009 to comply with Enterprise Bargaining Agreements;
- the substitution of our demand forecasts with those of the Australian Energy Market Operator despite strong evidence their forecasts are not 'fit for purpose';
- the exclusion of IT operating costs from our base year operating expenditure will result in cross-subsidies and inefficient consumption decisions;
- the removal of a number of operating expenditure step changes despite these step changes clearly satisfying the operating expenditure criteria;
- the removal of a number of capital expenditure projects or programs which are required for us to prudently and efficiently manage the network over the next regulatory control period;
- an error in the adjustment to our proposed actual inflation input in the AER's roll forward model;
- the definitions included for a number of nominated pass through events; and
- arbitrary adjustments applied to our efficient meter purchase and installation costs.

The issues discussed in this chapter are expanded upon in the following respective chapters of this revised regulatory proposal.

1.1 Introduction

We are satisfied the AER's preliminary determination recognises elements of our regulatory proposal and sees merit in the majority of our investment priorities including:

- protecting the safety of our customers, the community and our network;
- ensuring a resilient network for inner Melbourne (maintain cost-effective reliability);
- managing network growth (growing with Melbourne);
- building the network for the future; and
- making it easier for our customers.

We are also pleased in making its preliminary determination, the AER recognised we are the most efficient and reliable network in Australia.

We are proud of our strong performance and reputation for safety, efficient operations and reliability that has provided our customers with outstanding value for money. However, we are concerned the rejection of several aspects of our regulatory proposal will limit our ability to continue to meet the expectations of our customers today and into the future.

For the decisions or conclusions we do not accept, we provide our reasons for contesting those decisions or conclusions in our revised regulatory proposal. Our revised regulatory proposal responds, in detail, to those aspects of the AER's preliminary determination.

1.2 Rate of return

In our revised regulatory proposal, we contend that, contrary to the achievement of the allowed rate of return objective (**ARORO**) and the requirements of the National Electricity Rules (**Rules**), the AER's estimate of the allowed rate of return in its preliminary determination is not commensurate with the efficient financing costs of the benchmark efficient entity (**BEE**) with a similar degree of risk as that which applies to us in respect of the provision of standard control services.

For the purposes of the revised regulatory proposal, we have adopted as a placeholder the AER's preliminary determination estimate for the return on equity and debt, given that there is no clarity on the New South Wales (**NSW**) Australian Competition Tribunal (**ACT**) decision timing and our averaging period is yet to occur. We do however expect that these placeholders will be substituted based on the methodologies outlined in the revised regulatory proposal in the final determination.

1.2.1 Return on equity

The method for estimating the return on equity proposed in the preliminary determination will not deliver a return on equity estimate that is consistent with the ARORO. Our revised regulatory proposal maintains that the available evidence demonstrates that the AER's estimate of the return on equity estimate is too low, and we contend that the ARORO is best achieved by adopting an approach that properly has regard to estimates of the return on equity from all relevant return on equity models.

Alternatively, even if the AER continues to rely solely on the Sharpe-Lintner Capital Asset Pricing Model (**SL-CAPM**) to estimate the return on equity as its foundation model, we contend that an alternative approach be adopted. This alternative approach would involve properly adjusting the SL-CAPM parameters to deliver a return on equity that contributes to the achievement of the ARORO and reflects prevailing market conditions, by:

- determining a robust 'starting point' equity beta estimated based on a sufficiently large sample of comparable businesses;
- making a transparent and empirically based adjustment to the equity beta estimate to account for the known shortcomings of the SL-CAPM, especially low beta bias and book-to-market bias; and
- deriving the market risk premium in a way that gives appropriate weight to measures of the prevailing market conditions.

1.2.2 Return on debt

We contend that the method for estimating the return on debt proposed by the AER in its preliminary determination will not deliver a return on debt estimate which contributes to the achievement of the ARORO and the Rules. Instead, we submit that:

- the efficient financing costs to be estimated pursuant to clause 6.5.2 of the Rules are required to be estimated using the trailing average approach; and
- that approach should be adopted immediately (i.e. without any transition).

Alternatively, even if the AER's approach to estimating efficient financing costs by reference to the financing practices that would emerge for an efficient benchmark entity were correct, the appropriate approach would be to adopt a hybrid form of transition where only the hedged base rate component of the return on debt is subject to a transition.

If this hybrid form of transition were to be adopted, it would be necessary to consider to what degree hedging would have been efficient. The empirical evidence demonstrates that the efficient hedging ratio under the previous on-the-day approach to minimise interest rate risk would have been approximately one third. Therefore, if a hybrid transition is to be adopted (i.e. if the AER’s view of efficient financing costs were correct), the transition should only apply to one third of the base rate, reflecting the extent to which a BEE would have been expected to hedge the base rate component.

1.2.3 Gamma

We maintain that the AER's estimate of gamma is based on an incorrect interpretation of the Rules and does not reflect the value of imputation credits to investors. As such, we contend that:

- the AER's estimate in its preliminary determination over-estimates gamma, with the result that the reduction to our overall return to account for the value of imputation credits is too large; and
- the estimate of gamma proposed in our regulatory proposal of 0.25 reflects the value of imputation credits to investors.

Moreover, even if the AER's interpretation of the Rules were correct, the AER's estimate of gamma cannot be supported. If gamma is to be estimated in accordance with the AER's approach, the evidence demonstrates that the best estimate is approximately 0.3.

1.3 Real price growth

1.3.1 Labour price escalator

We have updated our proposed labour price growth rates in our revised regulatory proposal.

Our proposed labour price growth rates are based on historical outcomes of Enterprise Bargaining Agreements (**EBAs**), namely our own EBAs until they expire in 2017 and then forecasts based on the EBAs of all Australian privately-owned electricity networks until the end of 2020. The requirement under the *Fair Work Act 2009* to comply with EBAs is a 'regulatory obligation or requirement' within the meaning of the National Electricity Law (**Law**) and the Rules. This means that our expenditure forecasts must allow for compliance with our existing EBAs and EBAs that we are likely to enter in the period after our EBAs expire.

In any event, our EBA-based forecasts are the most representative measure of expected prudent and efficient labour price growth in the 2016–2020 regulatory control period (and certainly more representative of prudent and efficient labour price growth than the Electricity Gas Water and Waste Services (**EGWW**) wage price index (**WPI**)).

The AER's own benchmarking indicates we are operating efficiently and the AER has used this finding both for the purpose of concluding that a revealed costs approach will result in operating expenditure forecasts required to achieve the operating expenditure objectives and for the purpose of reducing the operating expenditure of distributors that the AER has concluded are not operating efficiently. Failure on the part of the AER to reflect in our expenditure forecasts the EBA outcomes that enable us to realise that efficient expenditure outcome is internally inconsistent.

Further, the private sector EBA forecasts for the period 2018–2020 prepared by Frontier Economics included in our original regulatory proposal, and this revised regulatory proposal, are prudent and efficient. Frontier Economics has clearly demonstrated that EBA wage growth rates across the electricity network industry have been relatively stable over the past ten years, far more stable than the EGWW WPI over the same period. Given this, and the fact there has been no change to the factors underlying this stability (including the highly specialised nature of our workforce, the continued demand for labour of this kind and reasons related to the enterprise bargaining framework), there is no basis for assuming that the stability in EBA wage growth rates will not continue in the 2016–2020 regulatory control period.

1.3.2 Input price weightings for operating expenditure

We have applied the AER's approach of splitting operating expenditure into labour and non-labour components. Our labour component includes expenditure on employees, labour hire contracts and contracts for the provision of field services.

We however disagree with the AER's weightings of labour to non-labour and therefore have applied our own weightings based on actual operating expenditure over the period 2012–2014. We consider the AER's weightings have no proper basis and using our actual data will not diminish our incentives to choose the efficient input price mix.

1.3.3 Non-labour price growth

Whilst our regulatory proposal initially proposed a material price growth rate of zero, since submitting our regulatory proposal, the Australian dollar has fallen considerably against the United States of America dollar, with the result that we now expect real price growth in materials over the 2016–2020 regulatory control period. We have reflected this by proposing a real price growth for our 'non-labour' component of operating expenditure that is a weighted average of the real price growth rate for materials forecast by Jacobs Group (Australia) Pty Limited (for 'materials' expenditure) and a zero price growth rate for all other expenditure in our 'non-labour' component.

1.4 Demand forecasts

We consider our demand forecasts reflect a realistic expectation of demand for our network over the 2016–2020 regulatory control period.

Since our regulatory proposal, we have updated our demand forecasts following the 2014–2015 summer.

Importantly, our forecasting methodology ensures our demand forecasts reflect realistic demand requirements at the spatial level. This is essential for identification of future local network constraints and capital augmentation requirements. As acknowledged by the AER:[1]

> *Localised demand growth (spatial demand) drives the requirement for specific growth projects or programmes. Spatial demand is not uniform across the entire network:…*

Our demand forecasts therefore ensure that our capital and operating expenditure forecasts reflect those of an efficient and prudent distribution network service provider operating in our network area.

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[1] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 108.

We disagree our forecasts do not account for the impact on demand of recent and future changes in electricity markets. Our forecasting approach captures the impact on forecast demand of electricity market changes that:

- occurred during the most recent ten years, through the modelling process which relies on ten years of historical data; and
- changes in demand that are expected to have a greater impact in the future, through post-modelling adjustments.

We also dispute the AER's preliminary determination to substitute our forecasts for the Australian Energy Market Operator's (**AEMO**) connection point forecasts. AEMO's forecasts do not reflect a realistic expectation of demand because, amongst other things:

- AEMO's forecasts do not incorporate key drivers of demand, such as income, population and prices, at the connection point level;
- AEMO's baseline connection point forecasts are based solely on historical time trends; and
- AEMO's reconciliation process results in a simple proportional allocation of state-wide forecast demand growth across all connection points in Victoria.

AEMO has only been preparing its connection point forecasts since 2014. Its forecasting process is in its infancy and continues to evolve over time. Conversely, we have been preparing demand forecasts for our network for 21 years. We have a wealth of local knowledge and experience regarding our network characteristics and demand requirements. Notably, AEMO's 2015 connection point forecasts exclude the demand from one of our major direct connect customers. This error means AEMO's forecasts are not directly comparable with ours.

For our revised regulatory proposal, we had Cambridge Economic Policy Associates (**CEPA**) conduct an independent review of our forecasts and AEMO's forecasts against the AER's best practice demand forecasting principles and the requirements in the Rules and the Law. CEPA found our demand forecasts are more likely to achieve the Rules and hence the National Electricity Objective (**NEO**) than AEMOs.

AEMO's demand forecasts do not account for different demand characteristics at different connection points and therefore cannot reflect realistic demand forecasts at the spatial level. Consequently, AEMO's forecasts cannot provide a reasonable basis for forecasting our capital and operating expenditure requirements. As such, they cannot satisfy the AER's own best practice forecasting principles or the requirements of the Rules and the Law.

1.5 Operating expenditure

1.5.1 Adjustments to base year operating expenditure

The preliminary determination accepted the majority of our operating expenditure. As noted, the AER recognised our strong benchmarking performance and was satisfied using a revealed cost approach to determining our operating expenditure forecasts.

However in respect of adjustments to our base year, we still maintain our base year operating expenditure should be adjusted for the reclassification of our information technology (**IT**) operating costs from metering services to standard control services.

Further, we have not included the AER's proposed adjustment to remove operating expenditure for losses associated with the scrapping of assets. We consider such an adjustment incorrect because our base year operating expenditure does not include losses associated with the scrapping of assets.

Finally, we have included a revised forecast of guaranteed service level (**GSL**) payments over the 2016–2020 regulatory control period due to the Essential Services Commission of Victoria (**ESCV**) recently publishing a final decision that sets out changes to the GSL scheme for that period and, accordingly, impacts on forecast GSL payments.

1.5.2 Step changes

We contend our proposed operating expenditure step changes for monitoring IT security, mobile devices, decommissioning of the five zone substations and [redacted] is necessary to satisfy the operating expenditure criteria in clause 6.5.6(c) of the Rules. Specifically, we propose a:

- step change for monitoring IT security is necessary to manage the risk of security breaches to our IT systems. Contrary to the statements in the preliminary determination, the costs of monitoring our IT security systems on a 24-hour basis cannot be funded through our base year operating expenditure;
- step change for mobile devices represents an efficient substitution of capital expenditure and operating expenditure. Contrary to the statements in the preliminary determination, our proposal to move to an operating expenditure only model for mobile devices is efficient and, further, allowing the step change would not overcompensate us for the prudent and efficient cost of leasing new mobile devices;
- step change for decommissioning five zone substations is necessary in order to maintain compliance with our regulatory obligations under the *Electricity Safety Act 1998* (Vic) and the *Environment Protection Act 1970* (Vic). Since the costs associated with projects to decommission and remediate sites are not included in our base operating expenditure, it is necessary for us to be allowed this step change for our forecast operating expenditure to satisfy the operating expenditure criteria; and
- [redacted]

In addition, we propose additional step changes in our revised regulatory proposal in respect of:

- the introduction of cost-reflective tariffs through changes to the Rules. At the time we submitted our regulatory proposal, we did not have sufficient understanding of the costs resulting from the introduction of cost reflective tariffs. As we have now submitted our Tariff Structure Statement we have a clearer understanding of the impact these changes will have on our operating expenditure during the 2016–2020 regulatory control period. The costs include a mass market mail-out to help ensure our customers are aware of the introduction of the network tariff structure change and an increase in customer enquiries;
- regulatory information notice (**RIN**) compliance. In order to comply with the RIN requirements, we must provide data that is complete, accurate, at a granular level and complies with the RIN definitions and format. However, the particular definitions and reporting requirements in the RIN do not correspond with our financial accounts or our operational work delivery systems. The costs involve improving RIN data governance and data maturity and increased audit requirements; and
- the Victorian Government's decision to introduce chapter 5A of the Rules. The costs involve employees dealing with non-expedited connection services.

1.6 Capital expenditure

The AER acknowledges and approves many elements of our capital expenditure proposal. However, the AER did reject specific aspects of our capital expenditure proposal which we maintain is necessary to prudently and efficiently manage our network.

1.6.1 Network capital expenditure

Having regard to specific aspects of the AER's decision on network capital expenditure our revised regulatory proposal:

1. maintains that our innovative project to augment our 11kV and 66kV networks to transfer load from, and de-commission, our 22kV sub-transmission network served by the West Melbourne Terminal Station, in collaboration with AusNet Services Transmission represents the least cost option to address the condition of our network and is in the long-term interests of consumers with which the NEO is concerned;
2. maintains our proposed 'unmodelled' replacement capital expenditure, such as civil works and noise mitigation, included in our original regulatory proposal and highlights why this expenditure is not reflected in our most recent historical replacement expenditure and why this expenditure is necessary to meet our regulatory obligations and maintain the safety, security and reliability of our network;
3. reforecasts gross customer connections adopting the AER's forecasting approach as well as correcting the AER's methodology for calculating customer contributions. We have also taken account of the Victorian Government's planned introduction of Chapter 5A of the Rules; and
4. updates our network augmentation program to reflect our latest 2015 demand forecasts, resulting in some deferment of our augmentation capital expenditure.

1.6.2 Non-network capital expenditure

Our revised regulatory proposal is consistent with the forecast of non-network capital expenditure included in the preliminary determination for property, motor vehicles and other general non-network capital expenditure. However, we do not accept the following components of the preliminary determination in relation to IT and communications capital expenditure:

- the AER's removal of the entirety of our proposed RIN compliance expenditure; and
- the AER' s arbitrary reduction applied across all IT and communications capital expenditure.

Our revised regulatory proposal has also included new IT and communications capital expenditure required to implement the initiatives outlined by the Australian Energy Market Commission (**AEMC**) following its Power of Choice review. The impact of these initiatives was not included in the development of our regulatory proposal as sufficient details were not available at that time to robustly determine a forecast of costs. The AEMC has since published its final Rule in relation to meter contestability.

1.7 Regulatory asset base

We accept the AER's preliminary determination in respect of the roll forward of our regulatory asset base (**RAB**) to 1 January 2016, except for the AER's adjustment to our proposed actual inflation inputs.

We consider that the AER's treatment of actual inflation inputs to the roll forward model (**RFM**) is inappropriate. By inputting for year t the actual CPI inflation rate for year t (i.e. an un-lagged measure of inflation), the AER's approach:

- is non-compliant with clause 6.5.1(e)(3) of the Rules, entailing an adjustment for actual inflation that is inconsistent with the method used for the indexation of the control mechanism for standard control services during the preceding regulatory control period;
- involves inconsistent treatment between the indexation of our RAB for inflation and the real to nominal dollar conversions of net capital expenditure and depreciation within the AER's RFM; and
- results in a discontinuity in the indexation of our RAB for inflation by effectively skipping one year of inflation (being the annual change in CPI from the September quarter in 2009 to the September quarter in 2010) in the CPI inflation series applied to index our RAB.

1.7.1 Regulatory depreciation

We endorse the AER’s decision to use, and now propose to calculate regulatory depreciation using, the ‘base-line’ method (or ‘year-by-year tracking’ approach, as it is referred to in the AER’s preliminary determination). We consider that this approach, by keeping track of depreciation on each year’s capital expenditure for each asset class, represents the most accurate method of estimating depreciation.

We contest the AER's decision to assign our 'Victorian Bushfire Royal Commission (**VBRC**)' asset class with a standard asset life equivalent to that of our 'distribution system assets' asset class. In particular, we contend that armour rods, vibration dampers and spacers must be assigned a shorter standard asset life than that assigned to our distribution system assets. As such, our revised regulatory proposal divides the 'VBRC' asset class into relevant types of assets, which are each assigned an appropriate standard asset life for the purpose of calculating regulatory depreciation.

1.8 Uncertainty regime

In respect of the preliminary determination on the additional pass through events that are to apply for the 2016–2020 regulatory control period, we do not wholly accept the AER's preliminary determination on the definitions of:

- the insurance cap event;
- insurance credit risk event;
- natural disaster event;
- terrorism event; and
- retailer failure event.

Accordingly, we propose revisions to the AER's definitions of those events. In particular, we consider that there should be a specific reference to cyber-terrorism type attacks in the definition of the terrorism event. Further, we have revised the name of the retailer failure event to refer to it as a retailer insolvency event (consistent with the retailer insolvency event in the Rules) and the definition of that event to seek to ensure that the protection afforded to Victorian distributors remains consistent with that available to distributors in jurisdictions in which the National Energy Customer Framework applies.

1.9 Service target performance incentive scheme

As the best performing network in respect of reliability performance, we consider that there is now limited opportunity for further improvement across our network. We therefore maintain our position that the revenue at risk should be reduced to 2.5 per cent, which is consistent with the Rules, to ensure that the benefits to consumers warrant the reward or penalty available under the AER's service target performance incentive scheme.

In our view, a revenue at risk of 5 per cent creates a real risk of consumers incurring windfall financial gains and losses that reflect the impact on reliability of external factors rather than any changes in underlying reliability performance.

1.10 Metering services

We do not accept the preliminary decision with respect to allowed metering revenue and propose that our forecast metering expenditure in this revised regulatory proposal be determined by:

- updating our forecast metering expenditure to reflect the AEMC's final decision to extend the Victorian metering derogation until 1 December 2017;
- update our forecast metering expenditure to reflect changes to the foreign exchange rate (to better reflect current market conditions);
- apply our revised real price growth rates for standard control services;
- apply our revised proposed rate of return for standard control services; and
- apply the meter unit rates for meter purchases and meter replacement installation costs based on the approach in our regulatory proposal.

1.10.1 Metering purchase costs

We do not accept the AER's decision to substitute our unit rates in respect of meter purchase costs with those of AusNet Services and Jemena. The unit rates proposed in our regulatory proposal were based on quotes from our two preferred meter providers, selected by means of a rigorous tender process. We consider it unreasonable to substitute unit rates that result from the unique circumstances of other distributors. In particular:

- our unit rates reflect the combined cost of the meter and the network interface card (**NIC**) required for the meter to be compatible with our mesh radio communications network. The unit rates of AusNet Services relate to the purchase of the meter only; and
- the unit rates of AusNet Services and Jemena are premised on volume discounts. The availability of these discounts is premised on the higher meter volumes each business has proposed relative to us, due to their assumption that metering contestability will not be introduced until post-2020.

1.10.2 Metering installation costs

We do not accept the AER's decision to substitute our meter installation unit rates for its own estimates on the basis:

- the AER's belief that the time taken to replace a meter is less than that for new connections is incorrect. Meter replacement is in fact more labour intensive because meter replacement involves actioning our fault response process, and consequently, a reactive response to meter faults. As a result meter replacement cannot be coordinated with other works to minimise travel time; and
- in applying our field worker labour rate, the AER has only applied the business hours labour rate and excluded on-costs. This is unreasonable because meter faults occur after hours (as well as during business hours) and we are entitled to recover reasonable overheads associated with meter installation costs.

1.11 Alternative control services (other than metering services)

We accept the preliminary determination in respect of alternative control and negotiated services except that:

- we apply our proposed labour growth rates for standard control services to the calculation of labour cost escalation for alternative control services and public lighting; and
- we base our public lighting charges on the rate of return specified in our revised regulatory proposal.

Introduction 2

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2 Introduction

On 30 April 2015, we submitted our initial regulatory proposal for the 1 January 2016 to 31 December 2020 regulatory control period to the Australian Energy Regulator (**AER**) in accordance with clause 6.8.2 as modified by clause 11.60.3 of the National Electricity Rules (**Rules**). Unless otherwise indicated, references in this document to Chapter 6 of the Rules are references to Chapter 6 in version 58 of the Rules.[2]

The AER published its preliminary distribution determination[3] in accordance with clause 6.11.2 of the Rules on 29 October 2015.

This document and its attachments comprise our submission in relation to the revocation and substitution of the AER's preliminary distribution determination under clause 11.60.4 of the Rules, including our revisions to our initial regulatory proposal lodged with the AER on 30 April 2015 (collectively referred to herein as our 'revised regulatory proposal').

2.1 Regulatory context

As a monopoly service provider, we are subject to a comprehensive set of regulatory obligations designed to ensure appropriate outcomes for customers, the community and investors. We require a fair commercial return to enable us to deliver an appropriate level of network reliability, safety and customer service in an efficient and sustainable manner.

The AER is responsible for the economic regulation of our business. In undertaking this economic regulation role, the AER is required to do so in a manner that will, or is likely to, contribute to the achievement of the National Electricity Objective (**NEO**) as stated in section 7 of the National Electricity Law (**Law**).

The objective of the Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- price, quality, safety, reliability and security of supply of electricity; and
- the reliability, safety and security of the national electricity system.

The Victorian Government retains responsibility for setting service levels, while Energy Safe Victoria (**ESV**) is responsible for safety and technical regulation in Victoria.

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2 Clause 11.60.2 of the Rules provides that clause 11.60 prevails to the extent of any inconsistency over any other clause of the Rules. Clause 11.60.3(a) relevantly provides that 'current Chapter 6' applies in respect of the making of a distribution determination for an 'affected DNSP' (defined in clause 11.60.1 to include CitiPower for the next regulatory control period (defined in clause 11.60.1 to be the regulatory control period that immediately follows that ending 31 December 2015). 'Current chapter 6' is defined in clause 11.60.1 to mean Chapter 6 of the Rules as in force immediately after Schedules 1 and 3 of the National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 came into force. However, clause 11.65.2 relevantly provides that, from the commencement date of the National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013 references in rule 11.60 to 'current Chapter 6' are to be read as Chapter 6 of the Rules as in force immediately after the National Electricity Amendment (Network Service Provider Expenditure Objectives) Rule 2013 came into force. That rule came into force on 26 September 2013 contemporaneously with version 58 of the Rules. Furthermore, clause 11.65.2 states that references to 'current Chapter 6' in clause 11.60 are to be read in this way despite clause 11.60.2. We observe that clause 11.76.1(a) of the Rules provides that former Chapter 6 governs the making of a distribution determination (not including a tariff structure statement) for the initial regulatory control period (defined in clause 11.75.1 to mean the regulatory control period commencing 1 January 2016) of an affected DNSP (defined in clause 11.75.1 to include a Victorian DNSP). The term 'former Chapter 6' is defined in clause 11.70.1 of the Rules to mean Chapter 6 as in force immediately before Schedules 1, 3 and 4 of the National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 came into force. Those Schedules came into force on 1 December 2014 contemporaneously with version 65 of the Rules. However, unlike clause 11.65.2 of the Rules, clause 11.76.1(a) of the Rules is not effective in modifying the version of Chapter 6 that governs the making of the Victorian distribution determinations because it makes no mention of, and does not express any intent to contradict, clause 11.60.2 of the Rules. Nonetheless, CitiPower observes that, for all practical purposes, there is no difference between versions 58 and 65 of the Rules.

3 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015.

The AER is required to ensure that pricing outcomes, and the revenues on which they are predicated, are sufficient to enable us to undertake the capital and operating work programs required to deliver the service levels as defined by the Victorian Electricity Distribution Code (**Code**), comply with all applicable regulatory obligations and requirements and maintain the safety of the distribution system. The allowed pricing outcomes must also provide for a fair commercial return to our shareholders. We have developed our capital expenditure program and forecasts taking into account the requirements of the Code and consider that the proposed capital expenditure programs are sufficient to ensure that we comply with that Code.

In addition, at the time of preparing this revised regulatory proposal, a number of important consultations or decisions remain in progress including the timing of when Victoria will implement chapter 5A of the Rules, a component of the National Energy Customer Framework (**NECF**). This revised regulatory proposal reflects our best assessment of the impact of open Rule change processes and other deliberations. However, changes to regulatory arrangements that are determined subsequent to the submission of this revised regulatory proposal may require further consideration during the AER's determination process.

2.2 Structure of our revised regulatory proposal

Table 2.1 Chapters in our revised regulatory proposal

Chapter	Title	Description
1	Executive summary	Provides an overview of the differences between our revised regulatory proposal and the preliminary determination.
2	Introduction	Provides contextual information.
3	The NEO preferable decision	Details why the changes we have made from the preliminary determination constitute a NEO preferable decision.
4	Real price growth	Provides our rationale and forecast of labour, material and contract escalation in the 2016–2020 regulatory control period.
5	Demand and customer forecasts	Presents our rationale and demand and customer number forecasts for the 2016–2020 regulatory control period.
6	Operating expenditure	Details our rationale and operating expenditure forecast for the 2016–2020 regulatory control period.
7	Capital expenditure - network	Details our rationale and network related capital expenditure forecast for the 2016–2020 regulatory control period.
8	Capital expenditure - non-network	Details our rationale and non-network related capital expenditure forecast for the 2016–2020 regulatory control period.
9	Opening asset base, depreciation and inflation	Presents our positions and calculations with respect to the opening regulatory asset base, depreciation and inflation.
10	Rate of return, gamma and expected inflation	Addresses the allowed rate of return, the value of imputation credits (gamma) and the method for forecasting inflation.
11	Revenue requirement	Summarises the total revenues that will be recovered through our tariffs.
12	Incentive schemes	An explanation of the incentive schemes that will apply in the 2016–2020 regulatory control period.

Chapter	Title	Description
13	Managing uncertainty	An explanation of proposed pass through and contingent project events and triggers.
14	Metering	A description of the total revenues that will need to be recovered for metering services in the 2016–2020 regulatory control period.
15	Alternative control and negotiated services	Our proposed charges and terms for alternative control, public lighting and negotiated services for the 2016–2020 regulatory control period.
16	Glossary	Description of the defined terms within the revised regulatory proposal.
17	Attachments	Lists the attachments to this revised regulatory proposal.
18	Models	Lists the models attached to this revised regulatory proposal.
19	Regulatory information notice	Lists the regulatory information notice templates which have been updated for the purposes of the revised regulatory proposal.

Source: CitiPower

2.3 Determination timeframes and feedback opportunities

Following the submission of this revised regulatory proposal to the AER on 6 January 2016, interested parties will have the opportunity to make further submissions on the revised regulatory proposal and the AER's preliminary determination by 4 February 2016.

Following an assessment of this revised regulatory proposal and submissions received from interested parties, the AER will revoke the preliminary distribution determination and substitute the distribution determination by 29 April 2016.

The substitute distribution determination will take effect from the date it is made and will apply in respect of the 2016–2020 regulatory control period (clause 11.60.4(c) of the Rules). Any differences between the preliminary distribution determination and the substitute distribution determination that impact allowed revenues in the 2016 regulatory year will be addressed by adjusting the annual revenue requirements for one or more of the remaining regulatory years of the 2016–2020 regulatory control period by the difference between the amount of annual revenue requirement for the 2016 regulatory year approved by the AER in the preliminary distribution determination and that approved by the AER in the substituted distribution determination (clause 11.60.4(d) and (e) of the Rules).

Further information on our determination process can be found at the AER website:

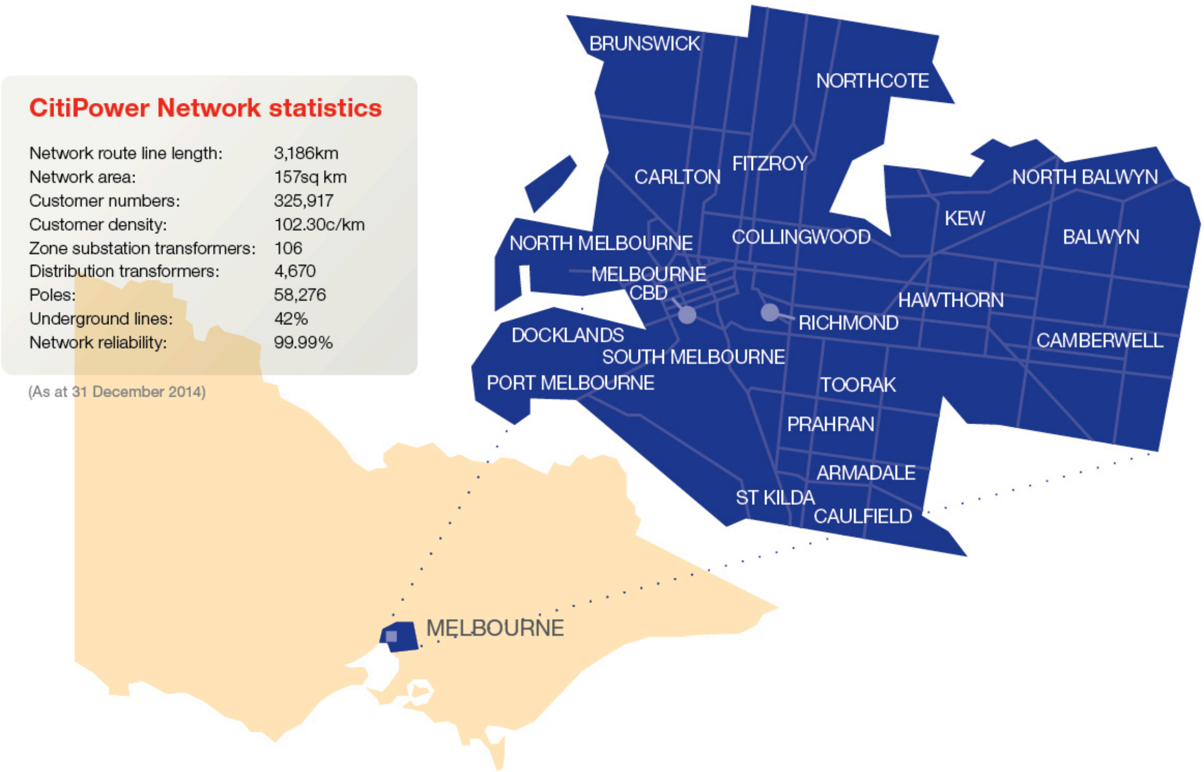
http://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/citipower-determination-2016-20

2.4 Our network

We own and operate an electricity distribution network serving 325,917 customers in a network of 157 square kilometres. This network includes the central business district (**CBD**) and inner suburbs including North Melbourne, Brunswick, Northcote, Carlton, Fitzroy, Collingwood, Richmond, Kew, Balwyn, Camberwell, Hawthorn, Armadale, St Kilda, South Melbourne and Port Melbourne.

Our network is the densest in Australia, with more than 102 customers per kilometre of line. It also has the highest proportion of CBD customers and portion of underground assets in Australia (around 42 per cent).

Figure 2.1 CitiPower network statistics



Source: CitiPower

Prior to 2004, our network was designed and operated on the basis that no loads would be interrupted in the event of the single failure of a major component of the network. This security criterion, known as 'N-1' for the networks ability to withstand one contingent failure without loss of load, has been reviewed in the light of an assessment of the impact such a failure would have in Melbourne and security criteria adopted in similar CBD networks around the world. The resultant review was subject to a regulatory test[4] and resulted in an amendment to the Code[5] in 2008.

Security of supply in inner Melbourne and its CBD is of paramount importance given the high concentration of people, commerce and cultural activities that depend on electricity supply each day. Catastrophic CBD network failures in Auckland, New York, London and Birmingham demonstrate that such failures can occur, and when they do, impose significant costs on the community and businesses.

4 CP PUBLIC ATT 3.4 - NERA, *Melbourne CBD Enhancement: Regulatory Test Analysis CitiPower*, April 2007.

5 CP PUBLIC ATT3.5 - ESCV, *Final Decision CBD Security of Supply*, February 2008.

2.5 Confidentiality

2.5.1 Law and Rule requirements

Section 18 of the Law provides that section 44AAF of the *Competition and Consumer Act 2010* (Cth) (**CCA**) has effect for the purposes of the Law and the Rules as if it formed part of the Law. Section 44AAF of the CCA requires the AER to take all reasonable measures to protect from unauthorised use or disclosure information given to it in confidence in, or in connection with, the performance of its functions or the exercise of its powers.

Clause 6.14(d) of the Rules precludes the AER from publishing any information in this revised regulatory proposal that is identified herein as confidential, except to the extent that any other provision of the Law or the Rules permits or requires the public release of that information by the AER (clause 6.14(e) of the Rules).

Clause 6.14A of the Rules requires the AER to make and publish, and have in force at all times after the date of their first publication, distribution confidentiality guidelines that specify the manner in which a Distribution Network Service Provider (**DNSP**) may make confidentiality claims in its regulatory proposal. The AER published its *Better Regulation Confidentiality Guideline* in accordance with this requirement in November 2013 (**Confidentiality Guideline**). The Guideline so published by the AER is binding on it and each DNSP to which it applies (clause 6.14A(d) of the Rules).

2.5.2 Our identification of confidential information and confidentiality claim

The AER's Confidentiality Guideline is not binding on the making of a confidentiality claim in respect of a submission of the present kind in relation to the revocation and substitution of the AER's preliminary determination pursuant to clause 11.60.4(b) of the Rules. Nonetheless, for the assistance of the AER, we have complied with that Guideline in identifying confidential information in this document and making its confidentiality claim in respect of that information.

Our completed confidentiality template is included as an attachment to this revised regulatory proposal. [6] Its proportion of confidential material notice is included in the confidentiality claim attachment.

We observe that we have sought to confine our claim of confidentiality to the greatest extent practicable, resulting in a comparatively modest confidentiality claim limited to the minimum confidential information in respect of which we consider non-disclosure essential to protect our legitimate commercial interests. Accordingly, we maintain that our confidentiality claim does not fetter to any extent consultation on our revised regulatory proposal in response to the AER's preliminary determination, nor does it give rise to any basis for the AER, acting reasonably, to reduce the weight accorded to any information adduced in, or in support of, our revised regulatory proposal.

2.6 Certification of the reasonableness of key assumptions

In accordance with clause S6.1.1(5) and S6.1.2(6) of the Rules, the key assumptions that underlie the capital and operating expenditure forecasts included in the CitiPower revised regulatory proposal have been certified by the Directors as being reasonable.

The Directors certification and the key assumptions that underlie the capital expenditure and operating expenditure forecasts are provided as an attachment to this revised regulatory proposal. [7]

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6 CitiPower, *Confidentiality Claim*, January 2016.

7 CitiPower, *Certification of reasonableness of key assumptions*, January 2016.

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The NEO preferable decision 3

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3 The NEO preferable decision

In making a distribution determination the Australian Energy Regulator (**AER**) must comply with a number of obligations imposed by the National Electricity Law (**Law**) that have the object of ensuring that the AER makes a decision that is preferable in respect of contributing to the achievement of the national electricity objective (**NEO**) (**NEO preferable decision**). Further, on review, the Australian Competition Tribunal (**Tribunal**) can only make a determination to vary or set aside the AER's decision on a distribution determination if it is satisfied that to do so will, or is likely to result in a decision that is materially preferable to the AER's decision in making a contribution to the achievement of the NEO (**materially preferable NEO decision**).

This chapter of our revised regulatory proposal addresses the NEO preferable decision and materially preferable NEO decision requirements of the Law. It describes aspects of the AER's preliminary determination which are unfavourable to the achievement of the NEO and why our revised regulatory proposal is NEO preferable.

As set out in this chapter, a decision to accept our revised regulatory proposal constitutes the NEO preferable decision and one that is materially preferable to the AER's preliminary determination in making a contribution to the achievement of the NEO.

3.1 Law requirements

3.1.1 AER's obligations in respect of NEO preferable decision

In making a distribution determination, section 16 of the Law provides that the AER must:

- perform or exercise a function or power under the Law or the National Electricity Rules (**Rules**) that relates to the making of a distribution determination in a manner that will or is likely to contribute to the achievement of the NEO;[8]
- take into account the revenue and pricing principles when exercising a discretion in making those parts of a distribution determination relating to direct control network services;[9]
- specify the manner in which the constituent components of the decision relate to each other and the manner in which that interrelationship has been taken into account in the making of the decision;[10] and
- if there are two or more decisions that will or are likely to contribute to the achievement of the NEO:
  - make the decision that it is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree; and
  - specify the reasons as to the basis on which the AER is satisfied that the decision it has made is the NEO preferable decision.[11]

The NEO is set out in section 7 of the Law and reads as follows:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for* the long term interests of consumers of electricity with respect to-
>
> *(a) price, quality, safety, reliability and security of supply of electricity; and*

[8] NEL, section 16(1)(a) and section 2(1) definition of 'AER economic regulatory function or power'.

[9] NEL, section 16(2)(a).

[10] NEL, section 16(1)(c) and sections 2(1) and 71A definitions of 'reviewable regulatory decision'.

[11] NEL, section 16(1)(c) and sections 2(1) and 71A definitions of 'reviewable regulatory decision'.

(b) the reliability, safety and security of the national electricity system.

The NEO operates together with the revenue and pricing principles in section 7A of the Law. The revenue and pricing principles relevantly include:

(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in-

(a) providing direct control network services; and

(b) complying with a regulatory obligation or requirement or making a regulatory payment.

(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes-

(a) efficient investment in a distribution system … with which the operator provides direct control network services; and

(b) the efficient provision of electricity network services; and

(c) the efficient use of the distribution system … with which the operator provides direct control network services.

…

(5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

3.1.2 Tribunal's obligations in respect of materially preferable NEO decision

Division 3A of Part 6 of the Law provides for merits review by the Tribunal of 'reviewable regulatory decisions', which include distribution determinations that set a regulatory period.[12] Under section 71P(1) and (2) of the Law, if the Tribunal grants leave for review of a reviewable regulatory decision, the Tribunal must make a determination in respect of the application for review which:

- affirms the reviewable regulatory decision; or
- varies the reviewable regulatory decision; or
- sets aside the reviewable regulatory decision and remits the matter back to the AER to make the decision again in accordance with any direction or recommendation of the Tribunal.

Under section 71P(2a) of the Law, the Tribunal can only make a determination to vary a reviewable regulatory decision under sub-section (2)(b) or to set aside the reviewable regulatory decision and remit the matter back to the AER under sub-section (2)(c) if:

- the Tribunal is satisfied that to do so will, or is likely to, result in a materially preferable NEO decision. If the Tribunal is not so satisfied it must affirm the decision; and

[12] 'Reviewable regulatory decision' is defined in section 71A to include a distribution determination, being either a network revenue or pricing determination (as defined in section 2 of the NEL), that sets a regulatory period. 'Network revenue or pricing determination' is defined in section 2 of the NEL to include a 'distribution determination'.

- in the case of a determination to vary the reviewable regulatory decision, the Tribunal is satisfied that to do so will not require the Tribunal to undertake an assessment of such complexity that the preferable course of action would be to set aside the reviewable regulatory decision and remit the matter to the AER to make the decision again.

Section 71P(2b) of the Law provides that in connection with the operation of section 71P(2a):

- the Tribunal must consider how the constituent components of the reviewable regulatory decision interrelate with each other and with the matters raised as a ground for review;
- without limiting the preceding sub-section, the Tribunal must take into account the revenue and pricing principles set out in section 7A of the Law;
- the Tribunal must, in assessing the extent of contribution to the achievement of the NEO, consider the reviewable regulatory decision as a whole; and
- the following matters must not, in themselves, determine the question about whether a materially preferable NEO decision exists:
  – the establishment of a ground for review under section 71C(1);
  – consequences for, or impacts on, the average annual regulated revenue of a regulated network service provider; and
  – that the amount that is specified in or derived from the reviewable regulatory decision exceeds the amount specified in section 71F(2).

Section 71P(2c) provides that if the Tribunal makes a determination to vary a reviewable regulatory decision or to set aside that decision and remit the matter back to the AER to make the decision again, the Tribunal must specify in its determination:

- the manner in which it has taken into account the interrelationship between the constituent components of the reviewable regulatory decision and how they relate to the matters raised as a ground for review as contemplated by sub-section (2b)(a); and
- in the case of a determination to vary the reviewable regulatory decision – the reasons why it is proceeding to make the variation in view of the requirements of sub-section (2a)(d).

3.2 The legal framework for NEO preferable decision making

In this section of our revised regulatory proposal we describe:

- the content and construction of the NEO;
- the role of the revenue and pricing principles;
- how the Rules with respect to the making of a distribution determination contribute to the achievement of the NEO and are consistent with the revenue and pricing principles;
- the AER's obligation to make the NEO preferable decision. In doing so, we describe the requirement to consider the overall decision and the relevance of interrelationships, decision making that contributes to the NEO and why unlawful decisions do not promote the NEO and are not NEO preferable; and
- the Tribunal's obligation on review to only make a determination to vary a reviewable regulatory decision or set aside that decision and remit the matter to the AER if it satisfied that to do so will, or is likely to result in, a materially preferable NEO decision.

3.2.1 The NEO

The NEO is an economic concept which requires the promotion of efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity and operates together with the revenue and pricing principles in section 7A of the Law.

In its decision paper on the review of the limited merits review regime under the Law, the Standing Council on Energy and Resources (**SCER**) (now the COAG Energy Council) correctly stated:[13]

> *The key objective of the national regulatory frameworks governing both electricity and gas in Australia is to promote the long term interests of energy consumers, as set out in the National Electricity Objective (NEO) and the National Gas Objective (NGO). This is delivered through efficient investment in (that is, ensuring required investment represents the best value for consumers over the long term, taking into account cost, timing, quality, safety, reliability and security of supply), operation and use of energy infrastructure.*

That the NEO is concerned with the concept of economic efficiency is apparent from the second reading speech for the Bill to introduce the new law and, in so doing, the NEO, which states:[14]

> *The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities. The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised.*

The NEO encompasses all three dimensions of efficiency in an economic sense, being productive, allocative and dynamic efficiency.

- *Productive efficiency* is achieved where individual firms produce the goods and services that they offer at least cost. The reference to efficient 'investment in' and 'operation of' electricity services in the NEO refers to productive efficiency, which can be achieved by using the least cost combination of both capital and operating inputs. Importantly, productive efficiency can be considered in both static (at a particular point in time) and dynamic terms (over a period of time).

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13 SCER, *Regulation impact statement limited merits review of decision-making in the electricity and gas regulatory frameworks decision paper,* 6 June 2013, p. 1. This has also been recognised by the Tribunal in similar terms. See, for example, CP PUBLIC APP D.2 - *Application by EnergyAustralia and others* [2009] ACompT 8 at [79]-[810], including in particular, the Tribunal's observation at [81] that the achievement of the efficiency objectives is the very purpose of the regulatory regime. SCER, *Regulation impact statement limited merits review of decision-making in the electricity and gas regulatory frameworks decision paper,* 6 June 2013 is 'Law extrinsic material' for the purposes of clause 8 of Schedule 2 to the NEL, being 'relevant material not forming part of this Law'. Accordingly, regard may permissibly be had to it in interpreting the preferable NEO decision requirement in clause 16(1)(d) of the Law to the extent that requirement is ambiguous or obscure or its ordinary meaning leads to a result that is manifestly absurd or unreasonable, or to confirm the interpretation conveyed by the ordinary meaning of the provision (NEL, Schedule 2, clause 8(2)). See also *Application by Energex Limited (No 4)* [2011] ACompT 4 at [21]-[22].

14 House of Assembly Hansard, *Second reading speech for the National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005*, 9 February 2005, p. 1452. Section 3 of the Law provides that Schedule 2 to the Law applies to the interpretation of the Law. Clause 7 of Schedule 2 to the Law provides that the interpretation of a provision of the Law that will best achieve the purpose or object of the Law is to be preferred to any other interpretation. Clause 8(2) of Schedule 2 to the Law provides that, in the interpretation of a Law provision, consideration may be given to 'Law extrinsic material' to provide an interpretation of an ambiguous or obscure provision, provide an interpretation that avoids a manifestly absurd or unreasonable result if the ordinary meaning leads to such a result or confirm the interpretation conveyed by the ordinary meaning of the provision. Clause 8(1) defines 'Law extrinsic material' to mean 'relevant material not forming part of this Law' and to include 'the speech made to the Legislative Council or House of Assembly of South Australia by the member in moving a motion that the Bill be read a second time'.

- *Allocative efficiency is achieved where the prices of resources reflect their underlying costs so that resources are then allocated* to their highest valued uses (i.e. those that provide the greatest benefit relative to costs). The reference to efficient 'use of' electricity services in the NEO refers to allocative efficiency. That is, the NEO will be promoted if decisions are made that result in a level and structure of prices that both enables the recovery of the cost of making electricity services available and maximises the extent to which consumers are able to purchase them at prices no greater than the utility they derive from using those services. Again, allocative efficiency can be considered in both static and dynamic terms.
- *Dynamic efficiency* reflects the capacity for industries to make timely changes to technology and products in response to changes in consumer tastes and in productive opportunities, to achieve the efficient production and allocation of goods and services over time. The reference in the NEO to 'efficient investment' for the 'long term interests of consumers' refers to dynamic efficiency. Promoting dynamic efficiency can be described as promoting productive and allocative efficiency through time.

The specific reference in the NEO to the interests of consumers in the 'long term', and the reduced emphasis it implies for short term considerations, further implies that the NEO will be promoted if decisions are made that give lesser weight to near-term productive and allocative efficiency gains and greater weight to long-term productive and allocative efficiency considerations (that is, to the long-term, dynamic aspect of efficiency).

The reference in the NEO to efficiency being 'for the long term interest of consumers', and 'with respect to' a number of expressly stated elements of an electricity service, serves to clearly articulate:

- the ultimate beneficiary of such efficiency, i.e. consumers;
- the relevant timeframe over which the efficiency objective should be interpreted in making regulatory decisions, i.e. the long term; and
- the particular dimensions of electricity services to which the efficiency objective must be directed, i.e. price, quality, safety, reliability and security of supply (and, importantly, in no way affords primacy to 'price' over those other important dimensions).

While the NEO is concerned with promoting economic efficiency, it is not correct to say that the NEO will necessarily be promoted by the outcome which reflects the lowest price to consumers in the short term. Economic efficiency in the context of the NEO is not solely concerned with 'price' in the short term but rather is also concerned with the efficient level of future costs (and therefore future prices) as well as the future level of the 'quality, safety, reliability and security of supply of electricity' and the 'reliability, safety and security of the national electricity system'. That is, it is incorrect to focus on the 'price' component in paragraph (a) of the NEO at the expense of the other components being 'quality, safety, reliability and security'. Further, in considering the 'price' component, it is critical to note that the focus of the NEO is on the long term interests of consumers, and therefore costs and prices in the long term, and not on short term price reductions which are unsustainable.[15]

The NEO effectively specifies that the level of service to be provided to consumers is that which is in their long term interests with respect to quality, safety, reliability and security of supply. In economic terms, such levels of service are those that customers value and are prepared to pay for, subject to the obligations with respect to those services with which the businesses are required to comply. For there to be allocative efficiency, the quality, safety, reliability and security of supply of electricity services should be at the level at which the incremental benefit placed by consumers on those factors is equal to their incremental cost.

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15 *Re Application by ElectraNet Pty Limited (No 3)*[2008] ACompT 3 at [15].

The NEO's focus on long term interests stresses the importance of dynamic efficiency. This ensures that even if consumers today value short term considerations such as price at the expense of the long term interests of future consumers, long term considerations such as future costs (and therefore future prices) and the quality, safety and reliability of supply are taken into consideration. The NEO's directive, with its emphasis on the long term interests of consumers and therefore on dynamic efficiency requires the AER to address consumers' recognised tendency to discount the future too heavily, resulting in a failure to invest sufficiently in the quality, safety, reliability and security of the supply of electricity services, leading to higher costs (and therefore prices) and lower service levels over the longer-term.

The phrase 'long term' is concerned with the period over which the full effects of the AER's decision will be felt.[16] The comments of the Tribunal on the phrase 'long term' in considering the objective of Part XIC of the *Trade Practices Act 1974* (Cth) (now the *Competition and Consumer Act 2010* (Cth) (**CCA**)), being the 'long term interests of end-users', are especially pertinent. The Tribunal observed:[17]

> *In considering how these elements may combine, it may be the case, for example, that very low prices are in the short-term interests of end-users. Over the long-term, however, sustainably low prices (which may be higher than the "very low prices" referred to above) are more likely to enhance their interests, as the long-term interests of end-users are likely to suffer in an environment characterised by short-lived operators who fall over soon after the customer signs with them, as distinct from one in which reliable service-providers offer competitive, but sustainable, services. Moves that enhance the quality and diversity of service may be subject to a similar analysis.*

The NEO is therefore concerned with the long term interests of consumers in sustainably low prices and the maintenance or enhancement of quality, safety, reliability and security, rather than the pursuit of price reductions in the short-term at the expense of their other interests. The Tribunal has recognised that:

- the long term interests of consumers set out in the NEO requires prices to reflect the long run cost of supply and to support efficient investment by providing investors with a return which covers the opportunity cost of capital required to deliver the relevant services;[18]
- the focus of the NEO is on the long term interests of consumers, not on short term price reductions which are unsustainable;[19] and
- the NEO is promoted where regulatory risk is minimised, and certainty of regulatory outcome is maximised.[20]

Similarly, in its decision paper on the review of the limited merits review regime under the Law, the SCER observed that:[21]

> *The long term interests of consumers are delivered through the timely investment in energy assets to meet quality, safety or reliability requirements, and to deliver secure supplies of energy. … In its economic regulation of network service providers rule change determination, the AEMC noted that efficient investment requires:*

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[16] *Re Seven Network Limited (No 4)* [2004] ACompT 11 at [120]; *Application by Chime Communications Pty Ltd (No 2)* [2009] ACompT 2 at [15], in discussing the objective of Part XIC of the *Trade Practices Act 1974* (Cth) (now the CCA), being the long term interests of end-users', on which the NEO was modelled.

[17] *Re Seven Network Limited (No 4)* [2004] ACompT 11 at [121].

[18] *Re Application by ElectraNet Pty Limited (No 3)*[2008] ACompT 3 at [15]; CP PUBLIC APP D.2 - *Application by EnergyAustralia and Others* [2009] ACompT 8 at [18].

[19] *Re Application by ElectraNet Pty Limited (No 3)* [2008] ACompT 3 at [251].

[20] *Re Application by ElectraNet Pty Limited (No 3)* [2008] ACompT 3 at [201].

[21] SCER, *Regulation impact statement limited merits review of decision-making in the electricity and gas regulatory frameworks decision paper,* 6 June 2013, p. 28.

- *there being a level of investment in network infrastructure so that safety and reliability standards are met in circumstances where consumers pay no more than is necessary for the network services they receive;*
- *the costs network businesses incur in providing network services to their customers reflecting efficient financing costs. This is to allow those businesses an opportunity to attract sufficient funds for investment while minimising the resultant costs that are borne by consumers;*
- *the establishment of a certain, robust and transparent regulatory environment. Investors will have more confidence and may be more likely to invest in monopoly infrastructure where the regulatory process is certain and robust, with appropriate checks and balances in place. Consumers will also have more confidence that the outcomes are better in such an environment; and*
- *regulatory certainty in the application of the improved and strengthened rules.*

> *[Footnote 36: AEMC, 2012. Rule determinations: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 and National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012 p 8.]*

The SCER has also affirmed that, consistent with the NEO, the objective of the limited merits review framework 'is to ensure that relevant decisions promote efficient investment in, operation, and use of energy infrastructure, and are consistent with the revenue and pricing principles of the Law …, in ways that best serve the long term interests of consumers'.[22]

3.2.2 The revenue and pricing principles

The revenue and pricing principles in section 7A of the Law can be taken to be consistent with and to promote the objectives in section 7 of the Law. The principles are themselves stated normatively in the form of what is intended to be achieved.[23]

The Tribunal has considered the first of these principles, being the principle that we should be provided with a reasonable opportunity to recover at least our efficient costs incurred in providing direct control network services and complying with a regulatory obligation or requirement or making a regulatory payment. The Tribunal stated as follows with respect to the intent and operation of that revenue and pricing principle:[24]

> *It might be asked why the NEL [National Electricity Law] principles require that the regulated NSP [Network Service Provider] be provided with the opportunity to recover at least its efficient costs. Why 'at least'? The issue of opportunity is critical to the answer. The regulatory framework does not guarantee recovery of costs, efficient or otherwise. Many events and circumstances, all characterized by various uncertainties, intervene between the ex ante regulatory setting of prices and the ex post assessment of whether costs were recovered. But if, as it were, the dice are loaded against the NSP at the outset by the regulator not providing the opportunity for it to recover its efficient costs (eg, by making insufficient provision for its operating costs or its cost of capital), then the NSP will not have the incentives to achieve the efficiency objectives, the achievement of which is the purpose of the regulatory regime.*
>
> *Thus, given that the regulatory setting of prices is determined prior to ascertaining the actual operating environment that will prevail during the regulatory control period, the regulatory framework may be said to*

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22 SCER, *Regulation impact statement limited merits review of decision-making in the electricity and gas regulatory frameworks decision paper*, 6 June 2013, pp. 1 and 10.

23 *Re Application by ElectraNet Pty Limited (No 3)* [2008] ACompT 3 at [79].

24 CP PUBLIC APP D.2 - *Application by EnergyAustralia and Others* [2009] ACompT 8, 27 May 2009 at [81]-[82].

err on the side of allowing at least the recovery of efficient costs. This is in the context of no adjustment generally being made after the event for changed circumstances.

3.2.3 The Rules

Chapter 6 of the Rules contains detailed prescription as to the making of a distribution determination by the AER. In particular, Chapter 6 of the Rules:

- specifies the constituent decisions on which a distribution determination is predicated;
- prescribes the use of a building block approach for the determination of allowed revenues; and
- contains detailed prescription of the manner in which the AER is to:
  - determine the various building blocks, including forecasts of operating expenditure and capital expenditure, the regulatory asset base (**RAB**), the return on capital, the estimated cost of corporate income tax and forecast depreciation; and
  - make its other constituent decisions, including those with respect to incentives schemes, the X factor, the additional pass through events to be specified in the distribution determination and contingent projects.

It must be assumed that the Rules with respect to the making of a distribution determination are intended to contribute to the achievement of the NEO and are consistent with the revenue and pricing principles. The reasonableness of this assumption is underlined by the role of the NEO and the revenue and pricing principles in the making of the Rules. In particular, the Australian Energy Market Commission (**AEMC**) may only make a Rule if it is satisfied that to do so will or is likely to contribute to the achievement of the NEO[25] and, in making a Rule with respect to distribution system revenue and pricing or the regulatory economic methodologies to be applied by the AER in making or amending a distribution determination, must also take into account the revenue and pricing principles.[26] Further, it may make a Rule that is different to a market initiated Rule if it is satisfied that the Rule will or is likely to better contribute to the achievement of the NEO.[27]

The building block approach to determining revenue allowances for a distribution determination, specified in clause 6.4.3 of the Rules, in particular, is constructed to ensure recovery by distributors of at least efficiently and prudently incurred costs, facilitating ongoing investment and promoting dynamic efficiency. Furthermore, each element of the building blocks is predicated, through constituent elements of the Rules, on costs that are at least efficient and prudent.

The operating expenditure and capital expenditure criteria set out in clauses 6.5.6(c) and 6.5.7(c) of the Rules, for example, are designed to ensure the expenditure allowances decided in a distribution determination reflect the efficient long run costs of achieving the operating expenditure and capital expenditure objectives set out in clauses 6.5.6(a) and 6.5.7(a) of the Rules, which in turn echo the interests of consumers of electricity with which the NEO is concerned, specifically the maintenance of quality, safety, reliability and security of supply and the reliability, safety and security of the national electricity system.

In so doing, Chapter 6 of the Rules ensures prices:

- provide a distributor with a reasonable opportunity to recover at least its efficient costs, consistent with the revenue and pricing principle set out in section 7A(2) of the Law; and

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25 NEL, section 88(1).

26 NEL, section 88B, and items 25 to 26J of Schedule 1 to the NEL.

27 NEL, section 91A.

- reflect the long run costs of supply and support efficient investment by providing investors with a return which covers the opportunity cost of capital required to deliver the relevant services, a result that, as discussed above, the Tribunal and policy-makers have recognised serves the long term interests of consumers referred to in the NEO.

The interrelationship between the operating expenditure and capital expenditure objectives and the achievement of economic efficiency (with which the NEO is primarily concerned) has been recognised by economic experts in reports prepared for, and submitted to, the AER by other distributors. For example, in its report prepared for Ausgrid on the economic interpretation of clauses 6.5.6 and 6.5.7 of the Rules, NERA Economic Consulting relevantly concluded:[28]

> *The construction of the expenditure assessment clauses 6.5.6 and 6.5.7 of the [Rules] reflects the dimensions of efficiency discussed in the previous section. Clauses 6.5.6(a) and 6.5.7(a) provide a set of expenditure objectives, which effectively define the outputs (or the process and principles for determining the outputs) that a DNSP is required to produce. The effect of these objectives is to establish the services to be produced by DNSPs, with the implication that the Ministerial Council on Energy (MCE) intended these to reflect the desired outcomes or benefits to society. In other words, clauses 6.5.6(a) and 6.5.7(a) effectively determine the parameters of allocative efficiency for the DNSPs.*
>
> *Clauses 6.5.6(c) and 6.5.7(c) then set out the criteria to be adopted by the AER in determining whether the DNSP is proposing to produce the required goods and services in a productively efficient way, ie, whether the costs are efficient and are the costs that a prudent operator would require to achieve the expenditure objectives. The evaluation of costs in these clauses is not limited to current costs, and so is also able to encompass a longer-term view of efficiency over time, ie, dynamic efficiency.*

That conclusion is expressly endorsed by HoustonKemp in its reports prepared for ActewAGL Distribution and Energex, which consider that the building block approach (including the building blocks calculated using forecast operating expenditure and forecast capital expenditure) is one of the essential elements of a framework of economic regulation that is capable of achieving the NEO.[29] More specifically, HoustonKemp concludes that:[30]

> *… each constituent component of the building blocks approach provides incentives and/or mechanisms that promote the threefold dimensions of efficiency, which represent the foundation of the NEO. In addition, the NEO requires that these components of the building blocks approach be applied such that, when there is tension between two elements of efficiency, the dynamic element is given preference so as 'to promote the long term interests of consumers'.*
>
> *…*
>
> *It follows that a decision that fails to comply with any constituent component of the building blocks approach will also fail to promote the NEO because it does not provide effective incentives and/or mechanisms for the promotion of efficiency. Therefore, if the AER were to make such a decision, it would not meet the requirement to contribute to the achievement of the NEO.*

Similar views have been expressed by economic experts in respect of the National Gas Objective (**NGO**), such as the reports prepared by HoustonKemp and Farrier Swier Consulting for ATCO Gas Australia[31] and Jemena Gas

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28 NERA, *Economic interpretation of clauses 6.5.6 and 6.5.7 of the National Electricity Rules, supplementary report, Ausgrid*, 8 May 2014, p. 9.

29 HoustonKemp, *AER determination for ActewAGL Distribution - contribution to NEO and preferable NEO decision*, 13 February 2015, p.16.

30 HoustonKemp, *AER preliminary decision for Energex - contribution to NEO and NEO preferable decision, a report for Allens*, 3 July 2015, pp. 15 to 16.

31 HoustonKemp, *Economic review of ERA's draft decision*, 27 November 2014 (ATCO Gas Australia's response to the WA Economic Regulation Authority's draft decision on required amendments to the access arrangements for the mid-west and south-west gas distribution systems).

Networks (NSW) Ltd[32] respectively. While such reports consider the NGO and were prepared, and provided to the AER, in the context of decision-making processes under the National Gas Law (**NGL**) and National Gas Rules (**NGR**), the conclusions reached are nonetheless equally applicable in the present context because, as recognised by the AER's own advisors:[33]

> *[t]he industries which are most likely to have similar characteristics to the gas distribution industry are other infrastructure network industries. And of these industries, electricity distribution is likely to be the most similar.*

Further, the NEO and the NGO are substantively similar and the building block approach is common to both the Rules and the NGR.

3.2.4 AER obligation to make the NEO preferable decision

As set out in the Law requirements at the beginning of this chapter, in making a distribution determination the AER must comply with a number of obligations imposed by section 16 of the Law that have the object of ensuring that a decision is made by the AER that is preferable in respect of contributing to the achievement of the NEO. Below we describe the AER's obligation to make the NEO preferable decision. In doing so, we describe the requirement to consider the overall decision and the relevance of interrelationships, decision making that contributes to the NEO and how unlawful decisions do not promote the NEO and are not NEO preferable.

Consideration of overall decision and relevance of interrelationships

It is the overall decision that must be NEO preferable. Therefore, the interrelationships between constituent components of the AER's decision, and how such interrelationships have been taken into account by the AER, will be relevant to the assessment of whether the decision made is the NEO preferable decision.

In introducing the requirements concerning interrelationships between constituent components and the making of the NEO preferable decision to section 16 of the Law, the SCER described these requirements as follows:[34]

> *For regulatory determinations, the regulator must:*
>
> *...*
>
> - *include in its final determination an explanation of the interlinkages between different component parts of its decision and how its overall decision is in the long term interests of consumers, in accordance with the NEO...*
>
> *In addition, the regulator, in regulatory determination processes, and the Tribunal, in review processes, must:*
>
> - *where there is discretion around a range of decisions, make the overall decision that, on balance, it considers is materially preferable in terms of serving the long term interests of consumers as set out in the NEO...*

Note that, while the SCER expressed the regulator's requirement concerning NEO preferable decision making in the same terms as that of the Tribunal (that is, to make the decision it considers is 'materially preferable'), the actual terms of section 16(1)(d) require the AER, in circumstances where there are two or more decisions that

[32] Farrier Swier Consulting, *Economic considerations for the interpretation of the national gas objective, expert report prepared by Geoff Swier for Jemena Gas Networks (NSW) Ltd*, 23 May 2014.

[33] Economic Insights, *Regulation of suppliers of gas pipeline services – gas sector productivity, initial report prepared for Commerce Commission*, 10 February 2011, p. 33.

[34] SCER, *Regulation impact statement limited merits review of decision-making in the electricity and gas regulatory frameworks decision paper*, 6 June 2013, p. 1 of SCER's policy position.

will or are likely to contribute to the achievement of the NEO, to make the decision that it is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree (i.e. the NEO preferable decision).

As it is the overall decision that must be NEO preferable, the existence of error in a decision does not, of itself, establish that the decision is not NEO preferable or that another decision is more preferable in making a contribution to the NEO. It is conceivable that the effect on the overall decision of two or more errors may offset one another, particularly given the interrelationships between constituent components of a distribution determination. At the same time, because of the interrelationships that exist between constituent components of a distribution determination, an error in the making of a decision may render the overall decision not NEO preferable.

These matters were discussed in an economic expert report recently prepared for, and submitted to the WA Economic Regulation Authority by, ATCO Gas Australia in the context of the analogous provisions of the NGL as follows:[35]

> *First, the process of assessing and reviewing elements of a regulatory decision necessarily involves making a series of determinations in relation to estimates or forecast future values of critical parameters. As a matter of principle, the judgments that must be applied may fall into error on either the upside or downside, with the effect that each may mitigate the other in terms of the end result. A requirement to consider the decision 'as a whole' against the materially preferable threshold, amounts to a practicable means for dealing in aggregate with a series of errors that, taken together, may not have much consequence.*
>
> *Second, many of the constituent decisions have economic linkages between one another, so that error in one has implications for another, even if, in its own terms, the second decision is appropriate. Further the emphasis on dynamic efficiency within the NGO - through its explicit emphasis given to the long term (as distinct from short term) interests of consumers, provides for the possibility that the correction of some errors warrants greater weight than the correction of others. By way of example, a depreciation decision that transferred the recovery of capital away from long term consumers and towards short term consumers should, on its face, receive a greater weighing in assessing what is preferable overall, than a depreciation decision that gave rise to the reverse effect.*

Decision making that contributes to the achievement of the NEO

A regulatory decision requires trade-offs between the competing efficiency objectives embodied in the NEO. This is best illustrated by a simple example: a decision to force substantial price decreases in the near term may increase short term allocative efficiency, but also have the potential to put at risk sustainable operations and investment plans, resulting in higher costs and reduced service levels in the future, and therefore detrimentally impact long term dynamic efficiency.

The NEO provides guidance on how these trade-offs should be resolved in specifying that the interests of consumers with which it is concerned are their interests in the 'long term'. The NEO's focus on long term interests, and thus on dynamic efficiency, ensures that even if consumers today value short term considerations such as price at the expense of the long term interests of future consumers, long term considerations such as future costs (and therefore future prices) and the quality, safety and reliability of supply are given precedence.

The building block approach and the revenue and pricing principles in the Rules and the Law respectively provide the essential elements of a framework of economic regulation that is capable of achieving the NEO. The building block approach and the revenue and pricing principles are designed to ensure that the AER's decisions will

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35 HoustonKemp, *Economic review of ERA's draft decision*, 27 November 2014, 27 November 2014, p. 34 (ATCO Gas Australia's response to the WA Economic Regulation Authority's draft decision on required amendments to the access arrangements for the mid-west and south-west gas distribution systems).

promote the NEO by ensuring that each of the three dimensions of efficiency encapsulated in the NEO are advanced in the AER's constituent decisions. It follows that a failure to give effect to each and every building block or to comply with each of the revenue and pricing principles will invariably compromise the achievement of the NEO.

As the revenue and pricing principles are the normative expression of the NEO, it can be assumed that a decision that is consistent with the revenue and pricing principles will contribute to the achievement of the NEO and that such a decision will, all else being equal, contribute to the achievement of the NEO to a greater degree than a decision that is not consistent with one or more of the revenue and pricing principles.

Similarly, since the Rules are properly assumed to contribute to the achievement of the NEO and to be consistent with the revenue and pricing principles, it follows that a decision that is consistent with the Rules, the scheme of the Rules and its object will contribute to the achievement of the NEO to a greater degree than a decision that is not consistent with the Rules, the scheme thereof or its object. It logically follows that any error or deficiency in the AER's constituent decisions in a distribution determination on the building blocks specified in clause 6.4.3 of the Rules that comprise a distributor's revenue allowances will, all else being equal, compromise the achievement of the NEO and result in a decision that cannot properly be said to be a NEO preferable decision.

Unlawful decisions do not promote the NEO and are not NEO preferable

A reviewable regulatory decision (including a distribution determination) made by the AER that is not in accordance with law cannot be said to contribute to the achievement of the NEO. Further, a decision that does not comply with the Rules or other legal requirements is not a 'possible' decision for the purposes of section 16(1)(d) of the Law. Rather, a decision is properly said to be a NEO preferable decision where, in the event that a range of decisions exist that are in accordance with law, it is to be preferred on the basis that it makes the greatest contribution to the achievement of the NEO.

It is evident from a consideration of the SCER's policy statements regarding the establishment of the materially preferable NEO decision requirement for the grant of relief by the Tribunal on review (see section 71(2a)(c) of the Law) that a reviewable regulatory decision, including a distribution determination made by the AER, that is not in accordance with law cannot be said to contribute to the achievement of the NEO or, thus, constitute a NEO preferable decision for the purposes of section 16(1)(d) of the Law.

In its decision paper on the review of the limited merits review regime under the Law, the SCER emphasised that the intent of the materially preferable NEO decision requirement in section 71P(a) of the Law is not to preclude the Tribunal from varying or setting aside and remitting a reviewable regulatory decision where this is necessary to deliver a correct decision; that is a decision made in accordance with law. The SCER observed:[36]

> *For the purposes of limited merits review applying to the energy sector under the NEL and NGL, the SCER is committed to ensuring that the approach adopted is consistent with wider administrative law, where the objective is to ensure that administrative decisions are 'correct or preferable'. That is, such decisions are:*
>
> - *correct, in the sense that they are made according to law; or*
> - *preferable, in the sense that, if there are a range of decisions that are correct in law, the decision settled upon is the best that could have been made on the basis of the relevant facts.*
>
> *It is not the intention of the SCER for limited merits review to result in decisions that are not consistent with law. However, SCER recognises that a focus on error correction may lead to less optimal outcomes, particularly*

[36] SCER, *Regulation impact statement limited merits review of decision-making in the electricity and gas regulatory frameworks decision paper,* 6 June 2013, pp. 9 to 10.

in complex determination processes where there may be disputes about many interlinked matters. In this context, 'error correction' means decisions that have been made without due regard to the facts, law and policy aspects of the original decision or decisions that should otherwise be 'preferable' decisions, as defined above. As set out in the consultation RIS, most decisions appealed under the limited merits review framework have been on subjective matters, where there are a range of decisions that are correct in law. Consequently, an undue focus on 'error correction', as defined above, reflects a failure of the limited merits review regime to deliver the policy intention.

It follows that a decision that is 'correct', in the sense that it is made according to law, is properly construed as being a 'materially preferable NEO decision' when compared to a purported decision of the AER that is not in accordance with law.

The expression 'according to law' may be construed as being a decision that the decision maker is empowered to make by the Law and the Rules, and which is otherwise consistent with the requirements of the Law and the Rules and of administrative law. However, the SCER recognised that there may be decisions that meet that criterion, which the Tribunal might nevertheless consider are attended by error in the manner in which the decisions are made in that one or more of the grounds of review in section 71C(1) of the Law exist.

It is important to bear in mind, in that context, that the grounds for review in section 71C(1) of the Law are potentially very broad in their application; they may, for instance, extend even beyond traditional administrative law review grounds, be capable of applying to constituent decisions, and/or involve subjective considerations (particularly as to the exercise of discretions) about which reasonable minds may differ. Accordingly, it is possible that an impugned reviewable regulatory decision has been made in accordance with law in the sense described above, despite the existence of a ground of review. It is for that reason that section 71P(2a)(d) of the Law expressly provides that the mere fact of the establishment of a ground for review under section 71C(1) of the Law must not determine whether a materially preferable NEO decision exists.

That situation may be contrasted with a decision that is not made in accordance with law, in the sense that it is not consistent with the Law and the Rules or the requirements of administrative law (for example, a decision that results from a misconstruction of a provision in the Rules, with the consequence that the decision maker was not authorised by those provisions to make the decision made). It could not be said that, where an error exists of that nature, the decision might nevertheless be a 'materially preferable NEO decision' which could not be varied or set aside to ensure that the decision made is in accordance with the requirements of the Law and the Rules and administrative law.

This approach is entirely consistent with the SCER's summary of its policy position concerning the intended effect of new sections 16(1)(d) and 71P(2a) of the Law as follows:[37]

[T]he regulator, in regulatory determination processes, and the Tribunal, in review processes, must … where there is discretion around a range of decisions, make the overall decision that, on balance, it considers is materially preferable in terms of serving the long term interests of consumers as set out in the NEO or NGO…

'Range of decisions', in this context, means a number of possible decisions that are each in accordance with law. That range of decisions does not include decisions which are not in accordance with the Law and the Rules and the requirements of administrative law, or a decision that is premised on an erroneous construction of a distribution determination made pursuant to the Law and the Rules. Put another way, a reviewable regulatory decision that is not made in accordance with law could not be regarded as a 'NEO decision' (that is, a decision which contributes to the achievement of the NEO).

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[37] SCER, *Regulation impact statement limited merits review of decision-making in the electricity and gas regulatory frameworks decision paper,* 6 June 2013, statement of 'SCER's policy position' in the preamble.

Such a construction of 'materially preferable NEO decision' is also consistent with a presumption that the provisions of the Law and the Rules promote their statutory object, being the NEO. Insofar as concerns the Rules, this is, in turn, consistent with the AEMC's express statutory obligation to make a Rule only if it is satisfied that the Rule will or is likely to contribute to the achievement of the NEO[38] and its statutory discretion to make a Rule that differs from a market initiated proposed Rule if the AEMC is satisfied that the more preferable Rule will or is likely to better contribute to the achievement of the NEO.[39]

Where there exists a discretion as to making one of a range of available decisions (i.e. there is more than one regulatory decision that is in accordance with law), section 16(1)(d) of the Law requires the AER to make the decision that will, or is likely to, contribute to the achievement of the NEO to the greatest degree. Further, section 71P(2a) of the Law requires the Tribunal to vary or set aside and remit the reviewable regulatory decision only if it is satisfied that doing so will, or is likely to, result in a decision that is materially preferable in making a contribution to the NEO. This latter requirement is discussed in further detail below.

3.2.5 Materially preferable NEO decision

The purpose of the new requirement

As noted above, under section 71P(2a)(c) of the Law, the Tribunal can only make a determination to vary a reviewable regulatory decision under section 71P(2)(b) of the Law or to set aside that decision and remit the matter back to the AER under section 71P(2)(c) of the Law if the Tribunal is satisfied that to do so will, or is likely to, result in a materially preferable NEO decision.[40] Although the 'materially preferable NEO decision' requirement is only relevant in circumstances where an application is made by a distributor under section 71B of the Law, for completeness we briefly consider the new limitation below.

The purpose of the new limitation on the Tribunal's power to vary or set aside a reviewable regulatory decision established by section 71P(2a) of the Law is two-fold, being to:

- require the Tribunal to give explicit consideration to the NEO in determining whether to vary or set aside and remit a reviewable regulatory decision, having regard in particular to the overall decision and the interrelationships between its constituent components; and
- confine the varying or setting aside and remission of a reviewable regulatory decision to circumstances in which doing so will make a material contribution to the achievement of the NEO.

That purpose is clearly supported by the SCER's conclusions in respect of the former merits review regime under the Law:[41]

> *… SCER considers that the majority of the reviews taken to the Tribunal to date relate to differences of opinion on components of a final decision. Consequently, the Tribunal's focus on 'error correction' in isolation was not appropriate for the highly complex interlinkages and contentious nature of the issues for which reviews were sought by monopoly electricity and gas network businesses.*

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[38] NEL, section 88.

[39] NEL, section 91A.

[40] For completeness, section 71P(2a)(d) of the Law provides that the Tribunal can only make a determination to vary a reviewable regulatory decision under section 71P(2)(b) of the Law if the Tribunal is satisfied that to do so will not require the Tribunal to undertake an assessment of such complexity that the preferable course of action would be to set aside the reviewable regulatory decision and remit the matter to the AER to make the decision again.

[41] SCER, *Regulation impact statement limited merits review of decision-making in the electricity and gas regulatory frameworks decision paper,* 6 June 2013, p. 6.

> *The complexity of the issues being investigated has also led to situations where error correction has occurred without apparent reference to how addressing the error contributes to the NEO or NGO. …*
>
> *… SCER notes the notices published by the Tribunal outlining its process and reasoning behind its decisions have not included reference to how the decisions are in the long term interests of consumers with respect to price, quality, safety, reliability, and security of supply of electricity or gas, respectively.*
>
> *It is this lack of information about how the review process has considered the 'facts, law and policy aspects of the original decision' that restricts the limited merits review regime in the full delivery of the original and recently clarified policy intent and is likely to continue to do so in the future if it is not addressed.*
>
> *In addition, SCER recognises the intention in establishing the review regime was for the review process to be used rarely and only to address issues with a material consequence in the context of delivering the NEO or NGO, and meeting the review and pricing principles. However, the error correction approach adopted by the Tribunal may be leading to more appeals than would otherwise be the case.*

Tribunal's required state of satisfaction

Section 71P(2a)(c) of the Law provides that the Tribunal must be satisfied that varying or setting aside and remitting an impugned regulatory decision 'will, or is likely to' to result in a materially preferable NEO decision.

Importantly, the proper construction of the words 'will, or is likely to' does not require the Tribunal to reach a state of satisfaction that the varied or set aside and remitted decision would be a materially preferable NEO decision on the balance of probabilities. Such a contention does not find support in the Law, Rules, extrinsic material or relevant case law. Requiring the Tribunal to be satisfied on the balance of probabilities would set the bar for intervention so high as to effectively preclude the Tribunal from performing the intended oversight of the AER's decision-making, thereby frustrating the very objectives of the merits review regime itself (including to maximise accountability and regulatory certainty through the availability of an appropriate review mechanism). That construction of section 71P(2a)(c) of the Law would also serve to erroneously conflate the two limbs of the provision (the first limb being 'will' result in a materially preferable NEO decision and the second being 'is likely to' result in a materially preferable NEO decision). As French J commented in *Australian Gas Light Company v Australian Competition and Consumer Commission and Others (No 3)* (2003) 137 FCR 317 (at paragraph [347]), in considering the expression 'would have, or would be likely to have' found in section 50 of the CCA:

> *[A]s a matter of construction if "likely" simply meant more probably than not, it would be difficult to distinguish the application of that limb of the formula from the application of the first limb which, having regard to the onus of proof applicable in proceedings under Part IV [of the CCA], could be established on the balance of probabilities.*

By way of analogy, the above observation can equally be said of the formula 'will, or is likely to' in section 71P(2a)(c) of the Law.

The alternative and preferred construction of the Tribunal's required state of satisfaction is that there must be a 'real chance' that varying or setting aside and remitting the impugned decision would result in a materially preferable NEO decision. This construction finds support in the relevant case law, for example in the above-mentioned judgment of French J (at paragraph [343]):

> *In my opinion, having regard to the statutory context provided by the other sections of Pt IV the correct construction is that 'likely' refers to a significant finite probability or "a real chance" rather than "more probable than not". Although there has been some divergence in the construction of "likely" in various provisions of the Act, the weight of authority supports the wider view.*

The meaning of 'materially preferable'

The words 'materially preferable' ought to be construed according to their natural and ordinary meaning and in the broader context in which they appear. This requires consideration of the general purpose and policy of the provision (in particular, the particular mischief that the provision is seeking to remedy) and the structure and purpose of the merits review regime in the Law.

The Macquarie Dictionary provides that something is 'preferable' if it is more desirable or worthy of being preferred, and that the adjective 'materially' means considerable or to an important degree. There is no indication that 'materially' should be considered synonymous with 'substantially' often employed in legislative drafting. Rather, the word 'materially' indicates that, as compared to the impugned decision of the AER, the outcome contended for by a distributor must make more than a trivial or immaterial difference in contributing to the achievement of the NEO.

The relevant extrinsic material confirms that the phrase 'materially preferable NEO decision' was not intended to be narrowly construed and, instead, ought to be broadly construed and will depend on the particular facts and circumstances in the particular case (and the particular decision under consideration). In respect of the requirements on the Tribunal in its decision-making, the SCER stated that:[42]

> *... [the former] limited merits review has failed to deliver on the policy intent in the at its decisions have not been linked back to the long term interests of consumers as set out in the NEO and NGO. It is SCER's view that this link to the statutory objectives needs to be made explicit in the limited merits review framework. Consequently, SCER considers that, consistent with requirements in the original decision process, the Tribunal should be required to demonstrate that its decision is materially preferable to the decision under review in the context of the long term interests of consumers as set out in the NEO or NGO.*
>
> *SCER also agrees with the Panel's finding that reviews to date have been unduly narrow in focus, which is inconsistent with the original intention in establishing the framework. Consequently, SCER considers that it should be explicit that the Tribunal should take into account matters which are interlinked with the matter(s) raised as the grounds for review.*
>
> *In making its decision, the Tribunal must consider these interlinked matters and how, in combination, these contribute to the delivery of the NEO and NGO. SCER considers that this will ensure that relevant balancing factors and contradictory views are able to be given due regard during reviews, thereby aligning the original decision process and the review process. Ultimately, this will contribute to ensuring that the long term interests of consumers as set out in the NEO and NGO are the primary focus of both the original decision - maker and the Tribunal.*

It is apparent that the particular mischief intended to be remedied by the introduction of the 'materially preferable NEO decision' requirement was the concern that previous Tribunal decisions were not adequately 'linked back' to the long term interests of consumers. As to the extent of that linkage to the NEO, the absence of any criteria against which 'materially preferable' is to be assessed gives the Tribunal a broad discretion to consider the facts and circumstances of the particular case. This is supported by the review panel (in their Stage 2 Report), which relevantly recommended:[43]

> *that the meaning of 'materiality' should be left largely to the discretion of the review body to determine in each case, in the light of the particular circumstances of the case.*

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42 SCER, *Regulation impact statement limited merits review of decision-making in the electricity and gas regulatory frameworks decision paper,* 6 June 2013, p. 41.

43 G Yarrow, M Egan and J Tamblyn, *Review of the limited merits review regime: stage two report*, 30 September 2012, pp. 35 and 39.

The 'materially preferable' requirement must be considered in the context of the merits review regime in the Law. Two aspects of the merits review regime are important for present purposes:

- first, leave must be granted for an applicant to apply for merits review in the Tribunal (section 71B(1) of the Law). Leave will only be granted if the applicant demonstrates that there is a serious issue to be heard as to whether a ground of review exists and the applicant has established a prima facie case that a determination by the Tribunal varying or setting aside and remitting the reviewable regulatory decision would result in a materially preferable NEO decision. In addition, section 71F of the Law requires that the amount specified in or derived from the decision must exceed the financial threshold before leave can be granted; and
- secondly, review is limited to the grounds of review set out in section 71C of the Law.

In combination, the leave thresholds and limited grounds of merits review ensure that filtering has taken place prior to an applicant reaching the stage at which the Tribunal must consider whether varying or setting aside and remitting the impugned decision would be materially preferable. It would be a perverse outcome if a Tribunal were to hear an application (i.e. the leave thresholds are met), determine for example that an error exists and that the error is material, and nonetheless refuse to grant relief. The materially preferable requirement merely ensures that any intervention of the Tribunal is warranted, having considered the overall scheme in which the regulatory decision is made and the long term interests of consumers.

Moreover, the 'materially preferable NEO decision' requirement is not the only instance of the word 'material' being employed to establish a threshold for relief in the regulatory scheme for the economic regulation established by the Law or Rules. Another instance is the cost pass through regime in clause 6.6.1 of the Rules, which is triggered by the occurrence of a 'pass through event', 'positive change event' or 'negative change event'. The term 'positive change event' is defined in Chapter 10 to mean 'a pass through event which entails the [distributor] *incurring materially higher costs* in providing direct control services than it would have incurred but for that event, but does not include a contingent project or an associated trigger event' (emphasis added). A negative change event is similarly defined, applying to circumstances where materially lower costs are incurred. For that reason, the word 'materially' is expressly defined in Chapter 10 to mean a 'change in costs … that the [distributor] has incurred and is likely to incur in any regulatory year of a regulatory control period, as a result of that event' that 'exceeds 1% of the annual revenue requirement for the [distributor] for that regulatory year'. The definition also expressly provides that, in other contexts, the word 'materially' bears its ordinary meaning.

In making its decision to include the materiality threshold in the cost pass through regime for distributors, the AEMC had regard to the threshold for cost pass through applications in transmission of one per cent of maximum allowed revenue.[44] In its rule proposal report, which proposed that materiality threshold for cost pass through applications in transmission, the AEMC observed that the incorporation of a materiality threshold was likely to limit the applications that may be made under the pass through mechanism, consistent with a view that it is only substantive changes in costs that should be covered by the mechanism.[45] Further, the AEMC considered in its 2012 rule determination with respect to cost pass through arrangements for network service providers that positive cost pass throughs exist in the Rules as a mechanism to allow network service providers to recover their efficient costs incurred as a result of events that could not be forecast as part of their regulatory or revenue proposal that otherwise would have a financial effect on the ability of network service providers to invest in and

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44 CP PUBLIC ATT 12.3 - AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012, p. 187.

45 AEMC, *Review of the electricity transmission revenue and pricing rules, transmission revenue: rule proposal report, draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, February 2006.

operate their networks.[46] It follows that the AEMC considers that amounts in excess of one per cent of our annual revenue requirement in a regulatory year are material and a failure to recover those amounts would have a financial effect on our ability to invest in and operate our distribution network.

While not determinative, the materiality threshold in the cost pass through regime provides insight, by way of analogy, into the extent to which the revenue impact of a particular decision might be considered 'material' for the purpose of satisfying the 'materially preferable' requirement in section 71P(2a)(c) of the Law. The materiality threshold in the cost pass through regime discloses that under-compensating a distributor by more than one per cent of its annual revenue requirement for any regulatory year is unfavourable to the achievement of the NEO.

3.3 Our revised regulatory proposal would deliver a materially preferable NEO decision

In this section, we describe the adverse implications of the preliminary determination for the long term interests of consumers with respect to price, quality, safety, reliability and security of supply of distribution services. Specifically, we:

- set out the impact of the AER's preliminary determination on our regulated revenue for the 2016–2020 regulatory control period;
- refer to elements of the preliminary determination which we have accepted in our revised regulatory proposal that are conservative in the sense that they are likely to result in under-compensation for efficient costs;
- explain why key elements of the AER's preliminary determination are not NEO preferable; and
- explain why a decision to accept our revised regulatory proposal would constitute the NEO preferable decision and one that is materially preferable to the AER's preliminary determination.

3.3.1 Revenue impact of the AER's preliminary determination

As compared to our revised regulatory proposal, the AER's preliminary determination in respect of several building blocks will have an adverse impact on our efficient required revenue for the 2016–2020 regulatory control period. Specifically:

- the impact on our regulated revenue for the 2016–2020 regulatory control period of the AER's preliminary decision on rate of change is approximately $17 million ($nominal), which constitutes a 1.2 per cent reduction in regulated revenue over that period;
- the impact on our regulated revenue for the 2016–2020 regulatory control period of the AER's preliminary decision on rate of return[47] is estimated to be approximately $248 million ($nominal), which constitutes a 17.5 per cent reduction in regulated revenue over that period;
- the impact on our regulated revenue for the 2016–2020 regulatory control period of the AER's preliminary decision on the value of imputation credits is approximately $23 million ($nominal), which constitutes a 1.7 per cent reduction in regulated revenue over that period;

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46 CP PUBLIC APP L.1 - AEMC, *Rule Determination National Electricity Amendment (Cost pass through arrangements for network service providers) Rule 2012*, 2 August 2012, pp. 2 and 9.

47 The AER's preliminary decision rate of return is assessed against a rate of return based on our proposed method using September 2015 as an averaging period.

- the impact on our regulated revenue for the 2016–2020 regulatory control period of the AER's preliminary decision on forecast capital expenditure is approximately $44 million ($nominal), which constitutes a 3.1 per cent reduction in regulated revenue over that period;
- the impact on our regulated revenue for the 2016–2020 regulatory control period of the AER's preliminary decision on forecast operating expenditure is approximately $42 million ($nominal), which constitutes a 2.9 per cent reduction in regulated revenue over that period;
- the impact on our regulated revenue for the 2016–2020 regulatory control period of the AER's preliminary decision on the allocation of capital expenditure to depreciation categories is approximately $11 million ($nominal), which constitutes a 0.8 per cent reduction in regulated revenue over that period; and
- the impact on our regulated revenue for the 2016–2020 regulatory control period of the AER's preliminary decision on the historic inflation applied in the roll forward of our RAB is approximately $10 million ($nominal), which constitutes a 0.7 per cent reduction in regulated revenue over that period.

A regulatory decision that sets revenue at materially less than the level otherwise determined by a proper application of the building block methodology set out in the Rules will fail to ensure the quality, safety, reliability and security of the supply of electricity, as required by the NEO. We consider that our revised proposal in respect of the above-mentioned building blocks represents a proper application of the building block methodology set out in the Rules. As such, accepting our revised regulatory proposal will result in a materially preferable NEO decision because it will:

- provide us with a reasonable opportunity to recover our efficient costs incurred in providing direct control network services and complying with regulatory obligations or requirements;
- provide an effective incentive to promote economic efficiency with respect to the investment in, and provision and use of, our distribution network; and
- allow a return commensurate with the regulatory and commercial risks involved in providing direct control network services.

Further, as set out above, the materiality threshold in the cost pass through regime provides insight, by way of analogy, into the extent to which the revenue impact of a particular decision might be considered 'material' for the purpose of satisfying the 'materially preferable' requirement in section 71P(2a)(c) of the Law. We observe that one per cent of our annual revenue requirement in a year of the regulatory control period is, on average, $2.8 million ($nominal). Having regard to the materiality threshold for cost pass through applications of one per cent of our annual revenue requirement in the relevant regulatory year and the adverse impact of the AER's preliminary determination on our regulated revenue for the 2016–2020 regulatory control period, it is clear that our revised regulatory proposal is materially preferable in contributing to the achievement of the NEO compared with the AER's distribution determination.

We observe that the following elements of our revised regulatory proposal render the outcome conservative, in that they tend towards the under-compensation of our business for efficient costs:

- in line with the AER's preliminary determination, we have revised our regulatory proposal in respect of debt raising costs to include only debt raising transaction costs. That is, we have not included liquidity costs and three month ahead financing costs in our revised regulatory proposal in circumstances where Incenta Economic Consulting's forecast of debt raising costs included those costs;
- we have not included an allowance for a new issue premium in estimating return on debt. In light of the evidence of a positive and new issue premium, making no allowance for this premium is highly conservative, in the sense that it is likely to lead to under-estimation of the efficient financing costs of a benchmark efficient entity;

- we observe that notwithstanding that the best forecast of inflation (on currently available information) in the 2016–2020 regulatory control period is 1.94 per cent, for the purposes of our revised regulatory proposal we have applied a forecast of inflation of 2.5 per cent derived using the AER's inflation forecasting method. The resultant impact on our regulated revenue for the 2016–2020 regulatory control period is approximately $49 million ($nominal), which constitutes a 3.5 per cent reduction in regulated revenue over that period; and
- we have accepted the AER's decision our proposed operating expenditure step change in respect of issuing the customer charter. We are required to issue a customer charter every five years and, accordingly, we will have to issue one during the 2016–2020 regulatory control period. However, the costs associated with issuing a customer charter are not reflected in our base year expenditure and, accordingly, the AER's decision fails to compensate us for those costs. Further, as a result of this under-compensation of our business relative to our efficient costs it is more likely that we will incur penalties under the efficiency benefit sharing scheme (**EBSS**) in circumstances where such penalties are not the product of management inefficiencies.

3.3.2 AER's preliminary determination is not NEO preferable

We provide the following explanation of key elements of the AER's preliminary determination which are not NEO preferable:

- the following decisions of the AER on the components of real price growth mean that we will not be provided with a sufficient opportunity to recover our efficient costs in providing direct control services:
  - the AER's decision on the real labour costs escalator in determining real price growth for operating and capital expenditure. The AER's rejection of our proposed enterprise bargaining agreement (**EBA**) based labour price growth rates will result in the insufficient escalation of our proposed operating and capital expenditure forecasts, directly hindering our opportunity to recover efficient costs incurred in providing standard control services. Further, since our forecasts of labour price growth are based on EBA outcomes, and given the obligation under the *Fair Work Act 1997* (Cth) to comply with EBAs is a 'regulatory obligation or requirement', the AER's rejection of our labour price growth rates will mean its expenditure forecasts do not allow for compliance with our regulatory obligations or requirements;
  - the AER's decision on input price weightings in determining real price growth for operating expenditure. The AER's input price weightings have no proper basis. In contrast, our proposed input price weightings are a robust measure of our 'labour' and non-labour' expenditure based on recent actual operating expenditure over the period 2012 to 2014. Since the AER determined that our base year operating expenditure is efficient the AER should consider that our split of labour and non-labour is efficient;
  - the AER's decision on the materials escalator in determining real price growth for operating expenditure and capital expenditure. The decline in the Australian dollar has raised the costs of many of the material inputs used by our business. In the absence of an adjustment for a decline in the dollar, we will not receive sufficient revenue to meet our operating and capital requirements; and
  - the AER's decision on the real contracts escalator in determining real price growth for capital expenditure.
- it is well-recognised in economic theory that if a distributor is undercompensated relative to efficient costs, this will detrimentally affect the distributor's ability and incentive to undertake efficient investment in, or the efficient operation and use of electricity services, contrary to the long term interests of consumers. This under-compensation of our business relative to our efficient costs is compounded as it is more likely that we will incur penalties under the capital expenditure sharing scheme (**CESS**) and EBSS in circumstances where such penalties are not the product of management inefficiencies;
- the AER's decision on the return on equity in determining the rate of return fails to reflect returns required by equity investors to invest in a benchmark efficient entity facing a similar degree of risk as that which

applies to us in respect of the provision of standard control services. Equity investors require an appropriate return on their investment in order to meet their financing requirements. The AER's estimate of the return on equity is too low and will result in under-compensation for investment now, and a negative signal for future compensation for investment, which can in turn be expected to deter efficient investment in our business. It is well-recognised in economic theory that investment below the efficient level detrimentally affects a distributor's ability to achieve efficiency improvements in the future; that is, it compromises productive efficiency outcomes in the long term. As such, the AER's decision on the return on equity will compromise the achievement of efficiency in the long term interests of consumers, with which the NEO is concerned;

- the AER's decision on the return on debt in determining the rate of return fails to provide a reasonable opportunity to recover at least the efficient debt financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to us in respect of the provision of standard control services. The AER’s approach to transitioning to the trailing average estimation method will lead to a return on debt allowance for the 2016–2020 regulatory control period that is below the efficient financing costs of a benchmark efficient entity for that period. As a result, the return on debt is less than what is required to promote efficient investment in, and efficient operation and use of, electricity services in the long term interests of consumers;
- the AER's decision on gamma, in calculating the estimated cost of corporate income tax, means that the overall return to equity-holders is less than what is required to promote efficient investment in, and efficient operation and use of, electricity services in the long term interests of consumers. The estimate of gamma must reflect the value that equity-holders place on imputation credits (not simply their face value or utilisation rate). Equity-holders require an appropriate return on their investment in order to meet their financing requirements. The AER has over-estimated gamma resulting in an understatement of the cost of corporate income tax. This understatement would provide us with an inadequate return for the 2016–2020 regulatory control period. As noted above, it is well-recognised in economic theory that, having been provided with an inadequate return, investment below the efficient level will detrimentally affect our ability to achieve efficiency improvements in the future. As such the outcome will compromise the achievement of efficiency outcomes in the long term interests of consumers;
- the AER's substitution of the demand forecasts proposed in our regulatory proposal with the Australian Energy Market Operator's connection point forecasts fails to provide a reasonable basis for forecasting our capital expenditure and operating expenditure requirements and therefore negatively impacts our ability to recover efficient costs required to meet or manage the expected demand for standard control services over the 2016–2020 regulatory control period. Specifically:
  - the AER's decision on demand forecasts in calculating augmentation expenditure will understate our need for augmentation expenditure. This will result in us being provided with insufficient revenue to meet growth in demand and customer connections over the 2016–2020 regulatory control period. This may potentially result in a decline in the reliability of our distribution system. This under-compensation of our business relative to our efficient costs is compounded as it is more likely that we will incur CESS penalties in circumstances where such penalties are not the product of management inefficiencies; and
  - the AER's decision on demand forecasts in determining output growth for operating expenditure will understate growth rates across our network which will result in us being provided with insufficient revenues having regard to our actual network growth over the 2016–2020 regulatory control period. This under-compensation of our business relative to our efficient costs is compounded as it is more likely that we will incur EBSS penalties in circumstances where such penalties are not the product of management inefficiencies;
- the AER's decision to reject our project to augment our 11kV and 66kV networks to transfer load from, and de-commission, our 22kV sub-transmission network served by the West Melbourne Terminal Station will

result in additional costs for customers, contrary to the long term interests of consumers. There are cost savings associated with this project which will not be realised for customers if this project does not occur;

- the AER's decision to reject our proposed capital expenditure for compliance with its regulatory information notices fails to provide us with a reasonable opportunity to recover our efficient costs incurred in providing standard control services. This under-compensation of our business relative to our efficient costs is compounded as it is more likely that we will incur CESS penalties in circumstances where such penalties are not the product of management inefficiencies;
- the errors in the AER's methodology for the calculation of customer contributions means that customers will not be levied cost reflective contributions for their connection to our network. This has the result that some customers will be required to cross-subsidise the connections of other customers resulting in inefficient connections to the network and is therefore contrary to the long term interests of consumers;
- the AER's decision to reject our proposed adjustment to base year operating expenditure for the reclassification of IT metering expenditure from metering services to standard control services is likely to have a distorting impact on price signals following the introduction of metering contestability as our metering tariffs will be overstated as a consequence. This will inefficiently encourage substitution away from us to other parties (for example, where we can provide metering services at lower cost). It is also contrary to cost-reflective pricing as metering infrastructure customers will cross-subsidise distribution customers. Further, this failure by the AER to correctly allocate our IT costs to standard control services interferes with our incentive to invest in our systems used to provide standard control services;
- the AER's decision to reject our proposed operating expenditure step changes in respect of monitoring IT security further discloses a focus by the AER on short term price reductions at the expense of long term productive and allocative efficiency (encompassing the quality, safety, reliability and security dimensions of supply) and, thus, the dynamic efficiency that the NEO directs should be accorded the balance of emphasis. Specifically:
  - our monitoring IT security step change is necessary to manage the risk of security breaches to our IT systems and maintain the safety, reliability and security of our distribution services through the supply of standard control services. The AER's decision to reject our proposed step change is likely to result in higher prices for customers over the medium to long term. If we are not allowed operating expenditure to monitor the security of our IT systems, we will have to inefficiently provide a capital expenditure solution to the issue which, due to the higher cost of such a solution, would result in higher prices for customers over the medium to long term;
  - our mobile devices step change represents an efficient substitution of capital expenditure for operating expenditure. The AER's decision to reject our proposed step change is likely to result in higher prices for our customers over the medium to long term. It is more efficient for us to procure mobile devices on a leasing arrangement rather than purchasing them. Accordingly, requiring us to purchase these devices as capital will result in higher prices for our customers over the medium to long term;
- [redacted]

- the AER's decision to reject our proposed operating expenditure step change for decommissioning zone substations is likely to compromise the safety, reliability and security of our distribution system. A failure to fund these works will create safety risks to the community. These sites contain oil, asbestos and other contaminants that result in environmental or health and safety risks. The AER's decision to reject this step change is a further example of the AER's focus on short term price reductions at the expense of the quality, safety, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system;
- the AER's decision to reject our proposal that the revenue at risk should be reduced to 2.5 per cent and to instead set it at 5 per cent creates a real risk of consumers incurring windfall financial gains and losses under the AER's service target performance incentive scheme that reflect the impact on reliability of external factors rather than changes in underlying reliability performance. A revenue at risk of 2.5 is consistent with the Rules' objective to ensure that the benefits to consumers warrant the reward or penalty available under that scheme. Setting revenue at risk at 5 per cent adversely affects our financial incentive to maintain and improve service performance;
- the AER's approach to mapping capital expenditure to depreciation asset categories does not reflect the economic lives of the assets and as such it cannot be said to be a NEO preferable decision;
- the AER's approach to indexing our RAB value for inflation is also contrary to the Rules and therefore does not contribute to the NEO. As such, it cannot be said to be a NEO preferable decision; and
- the AER's decision to substitute our unit rates in respect of meter purchase costs and meter replacement costs in determining forecast metering expenditure fails to allow us an opportunity to recover our efficient costs of providing metering services and therefore is contrary to the achievement of productive and allocative efficiency in the long term.

For the avoidance of doubt, this is not a complete list of aspects of the AER's preliminary determination which are not NEO preferable. There are other elements of the AER's preliminary determination which we do not accept and which are not NEO preferable. Those elements are described in the relevant chapters of our revised regulatory proposal.

3.3.3 Our revised regulatory proposal is NEO preferable

As noted above, it is the overall decision made by the AER that must be the NEO preferable decision, the assessment of which will require a consideration of any interrelationships between constituent components of the AER's decision and how such interrelationships have been taken into account by the AER.

The collective revenue impact of those aspects of the AER's preliminary determination that are not NEO preferable is approximately $395 million ($nominal). Having regard to that revenue impact alone, it is clear that those matters are material. As set out above, it is well-recognised in economic theory that if a distributor is undercompensated relative to efficient costs, this will detrimentally affect the distributor's ability and incentive to undertake efficient investment in, or the efficient operation and use of electricity services, contrary to the long term interests of consumers.

Since our revised regulatory proposal corrects the above aspects of the AER's distribution determination and ensures that we are provided with a reasonable opportunity to recover our efficient costs, an effective incentive to promote economic efficiency, and a return commensurate with the regulatory and commercial risks involved in providing direct control network services, considered collectively, a decision to accept our revised regulatory proposal constitutes the NEO preferable decision and one that is materially preferable to the AER's preliminary determination.

In forming this conclusion we have considered the interrelationships between the constituent components of the AER's decision and how such interrelationships have been taken into account by the AER. These interrelationships include:

- the interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt. We observe that clause 6.5.2(e) of the Rules also requires that in determining the allowed rate of return, regard be had to any relationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt. In our revised regulatory proposal, we:
  - consider that the return on equity and return on debt need to be estimated on the basis of a consistent approach to the allowed rate of return objective (**ARORO**), which is the touchstone for estimating the allowed rate of return. In this regard, we observe that the Rules require that:
    - the return on equity for a regulatory control period be estimated such that it contributes to the achievement of the ARORO, which renders our revised regulatory proposal conservative;[48] and
    - the return on debt for a regulatory year be estimated such that it contributes to the achievement of the ARORO;[49]
  - have taken into account the interrelationship between the return on equity and the value of imputation credits. Since the market risk premium needs to be grossed up for the value of imputation credits, a higher theta estimate implies a higher required return on equity;
  - have taken into account the interrelationship between the method for forecasting inflation and the amount that is deducted from the annual revenue requirement for indexation of the RAB and between the allowed rate of return and the method for forecasting inflation. Due to these interrelationships, the forecast of inflation needs to be accurate (i.e. as close as possible to actual inflation, which is used to roll forward the RAB at the end of the regulatory control period) and consistent with the implied forecast of inflation in the nominal rate of return. The best way to do this is to rely on the same dataset (i.e. market prices of securities) to estimate both. Nonetheless, as noted above, we have adopted a forecast of inflation derived using the AER's forecasting method for the purpose of this revised regulatory proposal only; and
  - do not accept the AER's suggestion that there is an interrelationship between the method for transitioning to the trailing average approach to estimating the return on debt and the equity beta;
- the interrelationship between forecast capital expenditure and other building blocks. In particular, we have had regard to the impact of the under-allowance of capital expenditure on forecast depreciation, corporate income tax and return on capital;
- the interrelationship between forecast demand and forecast capital and operating expenditure. In particular, in circumstances where the demand forecasts relied on by the AER do not represent a realistic expectation of demand for standard control services on our network over the 2016–2020 regulatory control period, this results in expenditure forecasts which do not reasonably reflect the operating expenditure and capital expenditure criteria;

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48 NER, clause 6.5.2(f).

49 NER, clause 6.5.2(h).

- the interrelationship between real price growth and forecast capital and operating expenditure. In particular, the AER's decision in respect of various components of real price growth results in expenditure forecasts which do not reasonably reflect the operating expenditure and capital expenditure criteria; and
- the trade-offs between undertaking capital expenditure projects and incurring operating expenditure. For example, as noted above, the AER's decision to reject our proposed operating expenditure step change in respect of mobile devices means that we will have to purchase these devices as capital which will result in higher prices for our customers over the medium to long term.

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Real price growth 4

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4 Real price growth

Real price growth accounts for expected changes in the real price of inputs to our operating and capital expenditure and is a key component of our total forecast operating and capital expenditure for the 2016–2020 regulatory control period.

The Australian Energy Regulator (**AER**) has erred in a multitude of ways in forecasting real price growth of operating expenditure over the 2016–2020 regulatory control period. The AER's failure to properly account for real price growth in the preliminary determination results in forecast operating and capital expenditure well below the level required to achieve the operating and capital expenditure objectives and reasonably reflect the operating and capital expenditure criteria.

Labour price growth rates

The AER erred in rejecting our proposed labour price growth rates.

Our proposed labour price growth rates are based on historical enterprise bargaining agreement (**EBA**) outcomes, namely our own EBAs until they expire and forecasts based on the EBAs of all Australian privately owned electricity networks thereafter.

The requirement under the *Fair Work Act 2009* (Cth) (**FW Act**) to comply with EBAs is a 'regulatory obligation or requirement' within the meaning of the National Electricity Law (**Law**) and the National Electricity Rules (**Rules**). This means that our expenditure forecasts must allow for compliance with our existing EBAs and EBAs we are likely to enter into for the period after our existing EBAs expire.

Our EBA-based forecasts are the most representative measure of expected prudent and efficient labour price growth in the 2016–2020 regulatory control period (and certainly more representative of prudent and efficient labour price growth than the Electricity Gas Water and Waste Services (**EGWW**) wage price index (**WPI**) used by the AER).

The AER's own benchmarking indicates that we are operating efficiently and the AER has used this finding to conclude that a revealed costs approach will result in operating expenditure forecasts required to achieve the operating expenditure objectives and reflect the operating expenditure criteria, and to reduce the operating expenditure of distributors that the AER concluded are not operating efficiently. Failure on the part of the AER to reflect in our expenditure forecasts the EBA outcomes that enable us to realise that efficient expenditure outcome is internally inconsistent. By honing in on wage price growth and failing to allow for the real price growth that flows from the arrangements underpinning our (efficient) base year operating expenditure, the AER produces systematically biased estimates.

Further, the EBA-based forecasts prepared by Frontier Economics are prudent and efficient. Frontier Economics has demonstrated that EBA wage growth rates across the electricity network industry have been relatively stable over the past ten years; and far more stable than the EGWW WPI over the same period. Given this, and as there has been no change to the factors resulting in such stability (including the highly specialised nature of our workforce, the continued demand for labour of this kind and reasons related to the enterprise bargaining framework), there is no basis for assuming that the stability in EBA wage growth rates will not continue in the 2016–2020 regulatory control period.

The AER's view that efficiency incentives are not retained under our approach underplays the significance of the strong commercial incentives to outperform regulatory allowances. These incentives include those under the incentive based regime established by the Rules whereby we are entitled to retain the benefit of outperforming AER allowances for the remainder of the regulatory control period and the *Efficiency benefit sharing scheme* (**EBSS**), as well as the further incentives resulting from the AER's reliance on benchmarking analysis. The AER does not explain why these incentives are eroded by our proposed approach.

We submit that our EBA-based forecasts should be applied to 100 per cent of our 'labour' component of operating and capital expenditure to account for real price growth of this expenditure in 2016–2020. However, even if the AER rejects our proposal, there is no basis for the AER to exclude EBA-based forecasts from the determination of forecasts of real price growth for labour costs entirely. Frontier Economics recommends that, in the event the AER does not apply EBA-based forecasts as the sole measure of labour price growth rates experienced by distributors, it should still recognise that those forecasts contribute very valuable information on the labour price growth rates experienced by distributors and a more reasonable approach would be for the AER to assign at least as much weight to EBA-based forecasts as it does to EGWW WPI forecasts.

Components of real price growth for operating expenditure

In response to the AER's preliminary determination, we have adopted the AER's approach of splitting operating expenditure into 'labour' and 'non-labour' components for the purposes of determining real price growth. Our labour component includes expenditure on employees and labour hire contracts, as well as expenditure on contracts for the provision of field services. Our 'non-labour' component comprises all other operating expenditure including contracts for the provision of non-field services).

We disagree with the weightings of labour and non-labour determined by the AER. The AER's input price weightings have no proper basis. The analysis by Pacific Economics Group (**PEG**) which the AER uses to develop its weightings, is over ten years old. More recent data, reflecting current best practice with respect to operating a distribution network and reported at a more granular level than the regulatory accounts relied on by PEG, is now available.

In addition, PEG did not derive weightings for 'labour' and 'non-labour' as suggested by the AER because the data did not allow for such a division. Rather, PEG engaged in the exercise of assigning price indexes to operating expenditure categories for the purposes of determining an overall input price index. The AER has assumed, without further analysis, that the expenditure categories to which PEG applied a 'labour cost index' fall within its 'labour' component and all other expenditure falls within its 'non-labour' component. This assumption is incorrect. The AER's use of the PEG analysis for the purposes of applying forecasts of real price growth is not appropriate in circumstances where the mapping exercise conducted by PEG does not align with the 'labour' and 'non-labour' components of operating expenditure defined by the AER. Our proposed weightings are a robust measure of our 'labour' and 'non-labour' expenditure, based on recent actual operating expenditure over the period 2012 to 2014.

We reject the AER's concern that using our actual data would create an incentive to adjust our input use in the base year. This is because the EBSS ensures we have a continuous incentive to make efficiency savings and the use of benchmarking further encourages the pursuit of efficiency. Additionally, the AER found us to be efficient and therefore adjusting the weightings that enable us to realise that outcome is internally inconsistent.

4.1 Rule requirements

Real price growth is part of the rate of change formula that the AER applies to operating expenditure to escalate base year expenditure for changes in the real price of inputs to operating expenditure over the forthcoming regulatory control period. Real price growth forecasts are also applied to escalate capital expenditure forecasts for changes in the real price of inputs to capital expenditure.

The requirements of the Rules governing real price growth forecasts are therefore those governing the forecast operating expenditure and forecast capital expenditure building blocks, outlined in chapters 6 and 7. In particular, clauses 6.5.6(c) and 6.5.7(c) of the Rules provide that the AER must accept the forecasts of required operating expenditure and capital expenditure if it is satisfied that the forecasts reasonably reflect each of the following (the operating and capital expenditure criteria):

- the efficient costs of achieving the operating or capital expenditure objectives;

- the costs that a prudent operator would require to achieve the operating or capital expenditure objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the operating or capital expenditure objectives.

The operating and capital expenditure objectives are set out in clauses 6.5.6(a) and 6.5.7(a) of the Rules and require (among other things) forecasts of operating and capital expenditure to include expenditure required to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.

In deciding whether it is satisfied that the proposed forecasts of operating and capital expenditure reasonably reflect the operating and capital expenditure criteria, clauses 6.5.6(e) and 6.5.7(e) of the Rules state that the AER must have regard to the operating and capital expenditure factors, which include (among other things) the AER's most recent annual benchmarking report and the benchmark operating and capital expenditure that would be incurred by an efficient distributor over the relevant regulatory control period.

In the event the AER does not accept our proposed forecasts of operating and capital expenditure, clauses 6.12.1(3)(ii) and 6.12.1(4)(ii) provide that the AER must determine an estimate of the total required operating and total required capital expenditure for the regulatory control period that reasonably reflects the operating and capital expenditure criteria, taking into account the operating and capital expenditure factors (as relevant).

4.2 Real price growth of operating expenditure

4.2.1 Components of real price growth and input price weighting

In response to the AER's preliminary determination, we have adopted the AER's approach of splitting operating expenditure into 'labour' and 'non-labour' components. Consistent with the AER's approach, our labour component includes expenditure on employees and labour hire contracts (in accordance with the definition of labour in the Category analysis (**CatA**) Regulatory Information Notice (**RIN**)), as well as expenditure on contracts for the provision of field services. Our 'non-labour' component (comprising all other expenditure) includes 'materials' and 'other' expenditure subcomponents.

Our definition of the 'labour' component of operating expenditure differs from the AER in that we have included all expenditure on contracts for the provision of field services, rather than just the labour related part of that expenditure. These services are primarily labour-based, which means that real price growth in wages is the key driver of real price growth in that expenditure overall. Accordingly (and for the further reasons described below), we are satisfied that defining our 'labour' component in this way allows for forecasts of operating expenditure required to meet the operating expenditure objectives and reasonably reflect the operating expenditure criteria.

We disagree with the AER's input price weightings. They have no proper basis and we have determined input price weightings based on our actual operating expenditure over the period 2012 to 2014.

Initial regulatory proposal

In our regulatory proposal we proposed to escalate operating expenditure for real price growth on the basis of three categories of expenditure: labour, contracts and materials.[50]

We applied our forecast real price growth rates for each category of expenditure to the proportion of operating expenditure attributable to each of labour, contracts and materials, as determined by reference to our actual expenditure in 2014 for standard control services. These weights are set out in the following table.

50 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 80.

Table 4.1 **Proportion of operating expenditure attributable to labour, contracts and materials (per cent)**

Expenditure type	Labour	Contracts	Materials
Operating expenditure	47.7	49.3	3.0

Source: CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 79.

AER's preliminary determination

The AER's preliminary determination proceeded on the basis of only two categories of operating expenditure for the purposes of forecasting real price growth: 'labour' and 'non-labour'. The AER stated that its 'labour' component includes both internal labour expenditure and expenditure on labour employed by contractors to provide 'field services' and the 'non-labour' component includes expenditure on labour employed by contractors that provide 'non-field services' (which the AER states are not unique to providing electricity distribution services), other contracts and materials.[51]

The AER rejected our proposed input price weights for estimating real price growth for operating expenditure (based on our three proposed components of operating expenditure) and instead adopted a 62 per cent weighting for its 'labour' component and a 38 per cent weighting for its 'non-labour' component.[52]

The AER stated that these weightings are consistent with the weightings used in the benchmarking analysis by its consultant, Economic Insights.[53] In determining weights for operating expenditure, Economic Insights relied on 2004 analysis by PEG of Victorian electricity distributors' regulatory accounts data.

Our response to the AER's preliminary determination

Components of real price growth

The way in which the components of real price growth are defined is significant because this in turn determines which measure of growth best reflects the real price growth of that component, and thus which measure will result in forecast operating expenditure required to achieve the operating expenditure objectives and reasonably reflect the operating expenditure criteria. The AER appeared, in places in the preliminary determination, to gloss over this in rejecting our proposed real price growth rates.

In defining the components of real price growth, it is relevant to consider both whether:

- the way in which the components are defined allows expenditure with the same cost drivers, or the same overall level of growth, to be grouped together; and
- the proportion of operating expenditure falling within that component can be robustly measured.

Failure to meet either of the above may suggest it is necessary to revisit the way in which the components of real price growth are defined for the purposes of determining real price growth of operating expenditure.

The AER set out the following rationale for its definition of the 'labour' component of real price growth (being internal labour and expenditure on labour employed by contractors that provide field services):[54]

> *We define labour this way so we only include the productivity related to providing field services in the productivity component of the opex cost function. This is true for both our measurement of historic*

51 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-60 to 7-61.

52 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 7-60 to 7-61.

53 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-61.

54 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-60.

productivity growth and the forecast productivity growth in our opex forecast. We do this because when we measure historic productivity growth we are interested in the productivity growth achieved by the service providers rather than the productivity growth achieved by contractors providing services that are not unique to electricity distribution.

This rationale for the AER's definition of the 'labour' component of real price growth is flawed for a number of reasons and has no basis in light of the AER's approach to assessing our proposed operating expenditure. For instance:

- in circumstances where the AER considered we are efficient and thus used a revealed costs approach to determine our operating expenditure forecasts (and not a forecast based on Economic Insights' 'opex cost function'), the treatment of the productivity component in the 'opex cost function' is irrelevant. Consistency in the formulation of the 'labour' component of real price growth with the productivity component in the 'opex cost function' is not a relevant consideration where the AER does not directly apply the 'opex cost function' in determining our forecast operating expenditure;
- in any event, the AER did not adopt the historic measure of productivity growth calculated by Economic Insights for the purposes of its preliminary determination. The historic productivity growth measured by Economic Insights was negative.[55] The AER advanced other reasons for applying zero productivity growth in its rate of change formula and it is therefore unclear why the AER continues to strive for consistency with the historic measure of productivity when this cannot be achieved given the AER's approach to determining productivity growth;
- in addition, and irrespective of the above, in measuring and forecasting productivity, the AER is in fact concerned with the efficiency of total network services operating expenditure[56] and not a subset of expenditure limited only to the expenditure related to 'field services'. The Economic Insights analysis relied on by the AER[57] assesses network services operating expenditure. In undertaking the benchmarking exercise, Economic Insights contemplates the exclusion of capital costs, depreciation, land tax and accounting related adjustments.[58] To our knowledge, Economic Insights does not exclude expenditure associated with contracts for the provision of what the AER calls 'non-field services'. To focus on a subset of expenditure other than network services operating expenditure would introduce a perverse result whereby expenditure on 'non-field services', which in some cases is not unique to electricity distribution, is nonetheless necessary for the purposes of providing standard control services, is not tested for efficiency; and
- the AER is also concerned with ensuring the efficiency of total operating expenditure in other contexts. In particular, operating expenditure on IT, accounting, legal and administrative services are subject to the EBSS, which applies to total operating expenditure.

We engaged Frontier Economics to consider the operating expenditure input price weightings in the preliminary determination. Frontier Economics' report, *Review of AER's preliminary decision on opex input weights*, is

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55 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-69.

56 Network services operating expenditure is total operating expenditure for standard control services excluding operating expenditure for metering, connection services, public lighting, amounts payable for easement levy or similar and transmission connection point planning.

57 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 7-68 to 7-71.

58 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, pp. 54-55. Economic Insights indicates in its November 2014 report that input specification issues were discussed in June 2013 report for the AER. CP PUBLIC ATT 5.1 - Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs, Report prepared for the Australian Energy Regulator*, 17 November 2014, p. 12.

attached to this revised regulatory proposal.[59] In considering the weightings adopted by the AER, Frontier Economics also raises concerns with the AER's definition of the 'labour' and 'non-labour' components.[60]

While we do not agree with the AER's reasons for its definition of the 'labour' component, as noted, the way in which the components of expenditure for determining real price growth are defined is significant only to the extent this then determines the forecast real price growth rates that should be applied to 'labour' and the measurement of the proportion of expenditure that falls within that component (that is, the input price weighting). Given 'labour' expenditure as we have defined it (which is broadly consistent with the AER's definition, except that all contracts expenditure on field services is included within that definition, rather than just the labour related expenditure):

- can be robustly measured; and
- is subject to the same cost drivers,

we consider that defining the 'labour' component of real price growth as including expenditure on employees and labour hire contracts, as well as contracts on expenditure for the provision of field services, will allow for forecasts of labour price growth over the 2016–2020 regulatory control period that result in operating expenditure required to achieve the operating expenditure objectives and reasonably reflect the operating expenditure criteria.

Input price weightings

The AER's operating expenditure input price weightings have no proper basis and result in forecast operating expenditure below the level required to achieve the operating expenditure objectives and reasonably reflect the operating expenditure criteria.

As noted, the AER relied on input weightings used by Economic Insights. Economic Insights in turn relied on 2004 analysis by PEG of Victorian electricity distributors' regulatory accounts data for 2003.[61] The PEG analysis was conducted in the context of determining a total factor productivity index. For this purpose, PEG engaged in the exercise of assigning price indexes from the Australian Bureau of Statistics (**ABS**) to operating and maintenance expenditure categories for the purposes of determining an overall operating and maintenance input price index as a weighted average of inflation in these indexes.[62]

We have a number of concerns with the AER's use of PEG's analysis as a basis for input price weightings.

First, the data on which the PEG analysis is based is over ten years old. More recent data, reflecting current best practice with respect to operating a distribution network and reported at a more granular level than the regulatory accounts relied on by PEG, is now available. This issue was highlighted by Economic Insights when it first applied the PEG weightings in its 2013 report for the AER. In setting out the PEG weightings for the purposes of determining the operating expenditure input price for its benchmarking, Economic Insights stated that:[63]

> *It would be appropriate to confirm that the PPIs and price index weights listed above reflect current NSP opex activities and opex composition. This can likely be done using information being collected as part of the AER's Category Analysis workstream.*

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59 Frontier Economics, *Review of AER's preliminary decision on opex input weights*, December 2015.

60 Frontier Economics, *Review of AER's preliminary decision on opex input weights*, December 2015, pp. vi, 12-13.

61 CP PUBLIC ATT 5.1 - Economic Insights, *Economic benchmarking assessment of operating expenditure for NSW and ACT electricity DNSPs, Report prepared for the Australian Energy Regulator*, 17 November 2014, p. 14.

62 PEG, *TFP research for Victoria's power distribution industry*, December 2004, p. 14.

63 Economic Insights, *Economic benchmarking of electricity network service providers*, 25 June 2013, p. 68.

Secondly, PEG did not derive weightings for 'labour' and 'non-labour' as suggested by the AER in its preliminary determination because the data did not allow for such a division. PEG stated in its report:[64]

> *We divided inputs into two categories: operation and maintenance (O&M) expenses and capital inputs. While it would have been desirable to divide O&M further into labor and non-labor inputs, reliable time series on DBs' labor expenses were not available.*

Thirdly, the AER's use of the PEG analysis for the purposes of applying real price growth forecasts is not appropriate in circumstances where the mapping exercise conducted by PEG does not align with the components of operating expenditure defined by the AER. The AER has assumed that the expenditure categories to which PEG applied a 'labour cost index' fall within its 'labour' component and the expenditure categories to which PEG applied producer price indexes (**PPIs**) fall within its 'non-labour' component. The AER has provided no basis for such an assumption.

To the contrary, there is evidence that there is no such alignment. For instance, PEG applies PPIs to 'Billing and revenue collection' and 'Customer service', which means under the AER's application of the weightings, the expenditure in this category is allocated to 'non-labour' and zero real price growth is applied. Given these services are labour-based and this labour is primarily provided by employees, the effective allocation of this expenditure to 'non-labour' through the use of PEG's weightings is inconsistent with the AER's definition of 'labour' as including employees.[65] It also results in operating expenditure on these services below that required to achieve the operating expenditure objectives and reasonably reflect the operating expenditure criteria. The jobs covered by our EBA with the Australian Services Union (**ASU**), Association of Professional Engineers, Scientists and Managers Australia (**APESMA**) and National Union of Workers (**NUW**) (**ASU/APESMA/NUW EBA**) include a range of jobs relating to billing, revenue protection and customer service.[66] The wage growth rates for these employees are the wage growth rates set out in the ASU/APESMA/NUW EBA, which exceed the consumer price index (**CPI**), yet CPI is the rate effectively applied if this expenditure is allocated to 'non-labour' as under the AER's use of the PEG weightings.

Fourthly, the AER has not reviewed the veracity of the data underpinning the weightings based on the 2003 data. A failure to do so leads the AER into error. A cursory review of the data shows, for example, that one distributor reported only 35 per cent of expenditure as falling within the cost categories to which PEG applied a 'labour cost index'.[67] In circumstances where the other distributors reported between 63 and 71 per cent of expenditure in these categories, it raises questions as to whether the way in which the data was reported can be relied upon to determine the weightings as PEG has done.

In responding to criticisms that the AER's weightings based on the PEG analysis are outdated, the AER considered 2014 operating expenditure data from the most efficient distributors according to its benchmarking analysis (the Victorian distributors, including CitiPower, and SA Power Networks). The AER determined input price weightings for 'labour', 'contracts' and 'other' expenditure for our business individually and a 'benchmark'.[68]

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64 PEG, *TFP research for Victoria's power distribution industry*, December 2004, pp. 5-6.

65 See clause 2 of the *CitiPower 2012–2014 corporate services agreement* (provided with the regulatory proposal (CP CONFIDENTIAL RIN 1.22) and the confidential definition of 'Customer Services' in Schedule 3 to that agreement) and the *CitiPower 2012 - 2014 resources agreement* (provided with the regulatory proposal (CP PUBLIC RIN 1.29)).

66 CP PUBLIC ATT 7.6 - *CitiPower (ASU, APESMA, NUW) Enterprise Agreement*, appendix 3.

67 PEG, *TFP research for Victoria's power distribution industry*, December 2004, table 5.

68 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-61.

The AER stated, however, that it has become increasingly difficult to ascertain the exact split between the labour component and the materials and services component of operating expenditure.[69] The AER stated that this is because:[70]

- there is greater use of contracting out of field services;
- the data provided does not differentiate between expenditure for contracts that provide field services and contracts that provide non-field services; and
- for those contracts that provide field services, only the labour related expenses should be allocated to the labour weighting.

The AER stated that, as a result, the 2014 actual operating expenditure data only enables it to identify that the labour weighting should be somewhere between 43 per cent (being the AER's 'benchmark' proportion of expenditure attributable to labour) and 83 per cent (being the AER's 'benchmark' proportion of expenditure attributable to labour plus contracts). The AER concluded that, in the absence of more precise information, the 62 per cent weighting for labour remains appropriate.[71]

The AER's concern that it has become 'increasingly difficult' to ascertain the exact split between the labour component and the materials and services component of operating expenditure with the move to greater use of contracting out of field services by distributors does not justify the application of the PEG weightings. First, as noted above, the ease with which a split could be ascertained on the basis of 2003 data has been overstated by the AER. Secondly, we have undertaken the exercise of allocating our actual expenditure between labour and non-labour components, which demonstrates the perceived difficulties are surmountable.

For the purposes of determining our input price weightings, consistent with our definition of the component, our proposed 'labour' component comprises:

- labour costs, as reported in response to the AER's CatA RIN;[72] and
- expenditure on field services contracts for maintenance services (including line inspection) which are primarily labour based services.[73]

While it is not possible to determine the precise proportion of our expenditure on field services contracts that is labour related, we consider that defining our 'labour' component in this way to determine the labour input price weighting nonetheless results in operating expenditure that reflects the operating expenditure criteria, taking into account the operating expenditure objectives. This is because:

- contracts expenditure of this kind is primarily for labour-based services and thus the main driver of cost increases in that expenditure is increased labour costs. That is, forecasts of labour price growth offer the best forecast of real price growth in this expenditure overall; and
- expenditure on contracts for 'non-field' services (which includes expenditure on labour employed by the relevant contractors) is included our 'non-labour' component. Given we expect real price growth in this

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69 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-61.

70 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 7-61 to 7-62.

71 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-62.

72 'Labour costs' are defined in Appendix F of the CatA RIN and broadly includes expenditure on employees and labour hire contracts. The reporting of these costs is subject to independent audit in accordance with Appendix C to the CatA RIN and verification by way of statutory declaration in the form set out in Appendix B to the CatA RIN: See AER, CatA RIN, pp. 1-2.

73 This expenditure data was sourced from the SAP accounting system. SAP is our primary financial reporting system, which is used to prepare our statutory accounts and responses to the AER's regulatory information notices, including the CatA RIN.

expenditure but it has, in effect, a zero price growth rate applied to it (as described further below), the overall result is a conservative estimate of real price growth.

The AER also rejected use of a distributor's own base year operating expenditure weightings to forecast price growth because it considered: [74]

- doing so would provide the distributor with an incentive to use more than the efficient proportion of internal labour in the base year to increase its forecast price growth and thus the AER cannot assume an individual distributor's operating expenditure price weightings are efficient even if its benchmarking analysis finds the distributor's base operating expenditure to be efficient; and
- our actual labour price weightings from 2009 to 2014 varied from 38 per cent to 49 per cent with the biggest variation from one year to the next being nine per cent, which suggests we have some capacity to respond to an incentive to increase the proportion of operating expenditure that relates to directly employed labour.

The AER indicated by way of example that we could reduce contracted services expenditure in the base year, which would result in a benefit under the EBSS and increase our rate of change allowance at the same time.[75]

We do not accept the AER's concerns in this regard. The reasons why these concerns are unfounded are described by Frontier Economics. By way of summary:[76]

- if the AER has judged our base year operating expenditure as efficient, there would be no sound basis to then argue that the input mix that gave rise to that base year operating expenditure is inefficient. A conclusion that overall expenditure is efficient is incompatible with a conclusion that the input mix is inefficient;
- the AER's use of benchmarking encourages the pursuit of efficiency;
- under the regulatory framework, distributors face incentive mechanisms that provide incentives to make savings whenever the opportunity arises, rather than deferring savings strategically. One of the key reasons for introducing the EBSS was to avoid gaming of the base year operating expenditure by providing a continuous incentive for efficiency; and
- the AER has overstated how easy it is in practice to change the input mix and assumes away the significant costs associated with doing so.

Regarding the AER's conclusions concerning the variability over time in our actual proportion of operating expenditure attributable to directly employed labour and our capacity to respond to an incentive to increase the proportion of operating expenditure that relates to employees, we also note that such changes reflect changes in our work program over time and the need to use external service providers to efficiently undertake increased work requirements.

In any event, even if the impact on distributors' behaviour from using a single year's expenditure to determine input price weightings was accepted to be significant, this does not justify abandoning all use of recent actual expenditure data. Rather, the AER's concerns can be allayed by determining the weightings by reference to an average over a numbers of years. This will ensure that there is no reason for distributors to reallocate expenditure between sources of labour in any given year. In light of the AER's concerns, we have determined our proposed input price weightings by reference to expenditure over three years (2012 to 2014). The use of an average over these three years is consistent with the AER's approach of using average expenditure between 2012

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[74] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-62.

[75] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-62.

[76] Frontier Economics, *Review of AER's preliminary decision on opex input weights*, December 2015, pp. vii, 14-17.

and 2014 to forecast the adjustment to our base year operating expenditure for changes in our capitalisation policy.[77]

Given the rate of real price growth of 'materials' expenditure now expected in the 2016–2020 regulatory control period (described further below), we also propose further breaking down our 'non-labour' expenditure into subcomponents of 'materials' and 'other' expenditure. Again, we have determined the proportion of 'non-labour' expenditure attributable to 'materials' and 'other' expenditure by reference to average expenditure between 2012 and 2014.

Our revised regulatory proposal

We now propose to apply real growth rates to 'labour' and 'non-labour' components of operating expenditure. Our 'labour' component includes our labour costs as reported in the response to the CatA RIN (broadly, expenditure on our employees and labour hire contracts) and expenditure on field services contracts for maintenance services (including line inspection). Our 'non-labour' component includes all other operating expenditure, which we propose further breaking down into subcomponents of 'materials' and 'other' expenditure.

We propose input price weightings for operating expenditure based on an average of our actual expenditure on labour and non-labour over the three year period 2012 to 2014. These weightings are set out in the following table.

Table 4.2 Proportion of operating expenditure attributable to labour and non-labour (per cent)

Expenditure type	Labour	Non-labour
Operating expenditure	68.7	31.3

Source: CitiPower

4.2.2 Labour price growth rates for operating expenditure

We reject the AER's use of the EGWW WPI to forecast labour price growth.

The requirement under the FW Act to comply with EBAs is a 'regulatory obligation or requirement' within the meaning of the Law and the Rules. This means that our expenditure forecasts must allow for compliance with our existing EBAs and EBAs we are likely to enter into for the period after our existing EBAs expire.

Accordingly, the concerns raised by the AER in respect of our EBA-based forecasts are misconceived and irrelevant. In any event, however, our EBA-based forecasts are the most representative measure of expected prudent and efficient labour price growth in the 2016–2020 regulatory control period (and certainly more representative of prudent and efficient labour price growth than the EGWW WPI used by the AER).

The AER's own benchmarking indicates we are operating efficiently and the AER has used this finding both for the purpose of concluding that a revealed cost approach will result in operating expenditure forecasts required to achieve the operating expenditure objectives and reflect the operating expenditure criteria, and for the purpose of reducing the operating expenditure of distributors that the AER has concluded are not operating efficiently. Failure on the part of the AER to reflect in our expenditure forecasts the EBA outcomes that enable us to realise that efficient expenditure outcome is internally inconsistent and amounts to cherry picking. By honing in on wage price growth and failing to allow for the real price growth that flows from the arrangements underpinning our (efficient) base year operating expenditure, the AER produces systematically biased estimates.

[77] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-43.

Further, the EBA-based forecasts prepared by Frontier Economics are prudent and efficient. Frontier Economics has demonstrated that EBA wage growth rates across the electricity network industry have been relatively stable over the past ten years, far more stable than the EGWW WPI over the same period. Given this, and as there has been no change to the factors resulting in such stability (including the highly specialised nature of our workforce, the continued demand for labour of this kind and reasons related to the enterprise bargaining framework), there is no basis for assuming that the stability in EBA wage growth rates will not continue in the 2016–2020 regulatory control period.

The AER's complaint that efficiency incentives are not retained under our approach underplays the significance of the strong commercial incentives to outperform regulatory allowances. These incentives include those under the incentive based regime established by the Rules whereby we are entitled to retain a share of the benefit of outperforming AER allowances under the EBSS and the Capital Expenditure Sharing Scheme (**CESS**), as well as the further incentives resulting from the AER's reliance on benchmarking analysis. The AER does not explain why these incentives are eroded by our proposed approach.

For the reasons outlined further in this chapter, we submit that our EBA-based forecasts should be applied to 100 per cent of our 'labour' component of operating expenditure to account for real price growth of this expenditure in 2016–2020. However, even if the AER rejects our proposal, there is no basis for the AER to exclude EBA-based forecasts from the determination of forecasts of real price growth for labour costs entirely. Frontier Economics recommends that, in the event the AER does not apply EBA-based forecasts as the sole measure of labour price growth rates experienced by distributors, it should still recognise that those forecasts contribute very valuable information on the labour price growth rates experienced by distributors and that rather than rejecting the EBA-based forecasts altogether, a more reasonable approach would be for the AER to assign at least as much weight to EBA-based forecasts as it does to EGWW WPI forecasts.

Initial regulatory proposal

As outlined above, in our regulatory proposal we proposed to escalate operating expenditure for real price growth on the basis of three categories of expenditure: labour, contracts and materials.[78]

For the purposes of our labour component, we proposed labour price growth forecasts:[79]

- for the period up until after the final payment contemplated under our two current EBAs (the CEPU EBA[80] and the ASU/APESMA/NUW EBA[81]), based on the actual annualised wage growth rates in our EBAs, weighted by reference to the proportion of employees on each EBA; and
- for the period after the final payment contemplated under the current EBAs until 2020, the five year historical average EBA wage growth rate for all Australian privately owned electricity networks as calculated by Frontier Economics.[82]

The resulting labour price growth rates are set out in the following table.

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78 CitiPower, *Regulatory proposal 2016–2020,* April 2015, p. 80.

79 CitiPower, *Regulatory Proposal 2016–2020*, chapter 7 and Appendix B (CP PUBLIC APP B).

80 CP PUBLIC ATT 7.9 - *Powercor Australia Ltd / CitiPower Pty and CEPU Enterprise Agreement*. The pay increases under the CEPU EBA are set out in clause 16, with the final pay increase on 1 July 2016. Consistent with the period for which prior increases were effective under the CEPU EBA, we assumed that wages for these employees will not increase again for six months (i.e. until 1 January 2017).

81 CP PUBLIC ATT 7.6 - *CitiPower (ASU, APESMA, NUW) Enterprise Agreement*. The pay increases under the ASU/APESMA/NUW EBA are set out in clause 16, with the final pay increase being for the first pay period on or after 1 July 2016. Consistent with the period for which prior increases effective under the ASU/APESMA/NUW EBA, we assumed that wages for these employees will not increase again for 12 months (i.e. until 1 July 2017).

82 CP PUBLIC ATT 7.3 - Frontier Economics, *Labour cost escalation forecasts using enterprise bargaining agreements*, February 2015.

Table 4.3 Regulatory proposal labour price growth forecasts (per cent)

Labour price growth rate	2016	2017	2018	2019	2020	Average 2016–2020
Nominal	4.52	4.33	4.33	4.33	4.33	4.37
Real	1.87	1.68	1.68	1.68	1.68	1.72

Source: CitiPower, *Regulatory Proposal 2016–2020*, April 2015, p. 74.

For operating expenditure on contracts (which are primarily for labour-based services), we proposed contracts growth rates based on construction sector WPI forecasts for Victoria prepared by the Centre for International Economics (**CIE**).[83]

AER's preliminary determination

For its 'labour' component, the AER rejected our proposed labour price growth forecasts and contracts growth rates and instead used an average of forecasts of the EGWW WPI growth rate for Victoria prepared by:

- Deloitte Access Economics (**DAE**) (for the AER); and
- BIS Shrapnel Pty Limited (**BIS Shrapnel**) (for Jemena Electricity Networks (Vic) Pty Ltd (**JEN**) and United Energy Distribution (**UED**)).

The AER raised a number of concerns regarding our proposed EBA-based labour price growth rates.

First, the AER characterised our proposed approach to forecasting labour price growth as a '*hybrid forecasting method*' because we '*did not adopt the same forecasting method across the entire forecast period*'.[84] The AER stated that using individual EBAs to forecast labour price growth at the start of the forecast period and an industry average for the remainder would not produce a forecast consistent with the operating expenditure criteria.[85] The AER observed by way of example that if a firm has higher wages than the industry average because it negotiated its latest EBA prior to the labour market softening, then you would expect, all else being equal, that the wage increases in its next EBA would be lower than the industry average (which average would also reflect conditions prior to the labour market softening).[86]

Secondly, the AER considered that our labour price growth forecasts do not account for the general and industry specific labour market conditions that it expects to prevail in the forecast period. The AER observed that wage increases in an individual EBA are affected by the market conditions at the time the EBA was negotiated. This means that forecasts based on our actual and other historic EBAs reflect historic market conditions, rather than expected market conditions. The AER noted that WPI growth rates, at both the Australian all industries and EGWW industry level, are currently the lowest on record, which means that forecast growth rates based on actual EBAs and historical average EBA growth rates will be higher than wage growth rates expected during the 2016–2020 regulatory control period.

Thirdly, the AER considered that our labour price growth forecasts do not account for the impact that wage negotiations of publicly owned electricity network service providers will have on negotiations in the forecast

83 CitiPower, *Regulatory Proposal 2016–2020*, p. 79.

84 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-55.

85 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 7-55 to 7-56.

86 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 7-55 to 7-56.

period.[87] The AER noted that Australian EGWW WPI increases are comparable to the EBA wage increases for electricity network service providers when public sector EBAs are included.[88]

Finally, the AER raised a concern with adopting forecasts based on our existing EBAs on the basis it considers this would reduce the incentive for distributors to negotiate efficient wages.[89]

The AER indicated that to the extent expenditure on contracts for the provision of services such as vegetation management, asset inspection, electrical construction, civil works and traffic management is operating expenditure, it would be included in the AER's 'labour' component since the expenditure is for field services.[90] The AER did not otherwise provide any reasoning for rejecting the use of the construction sector WPI for expenditure on labour employed by contractors that provide 'field services'.

The AER supported its use of the EGWW WPI to escalate its 'labour' component of operating expenditure by stating that the electricity industry makes up the majority of the EGWW industry.[91]

While the AER conceded that our proposed EBA-based forecasting method meets two of the principles set out in the *Expenditure forecast assessment guideline* (namely, it is simpler and more transparent than the EGWW forecasting methods adopted by DAE and BIS Shrapnel), the AER indicated that the consideration of these principles is a matter of balance and that, on balance, the forecast changes in EGWW WPI better meets the principles set out in the *Expenditure forecast assessment guideline* (in particular, the principles that the method should be valid, accurate and reliable, robust and fit for purpose).[92]

The AER considered that where a consultant is used to forecast labour prices, an averaging approach that takes into account the consultant's forecasting history, if available, is the best methodology for forecasting labour price growth.[93] Accordingly, the AER adopted an average of the forecast of the EGWW WPI from DAE and BIS Shrapnel as prior AER analysis indicated this produces estimates closest to actual growth.[94]

Our response to the AER's preliminary determination

The AER's reasons for rejecting our proposed EBA-based forecasts are flawed and provide no basis for rejecting our labour price growth rates.

<u>Compliance with our EBAs is compliance with a regulatory obligation or requirement</u>

We are bound by law to comply with EBAs and thus the AER is required to ensure our expenditure forecasts for the 2016–2020 regulatory control period compensate us for the costs of complying with our EBAs.

The requirement to comply with EBAs constitutes a requirement to comply with a 'regulatory obligation or requirement' within the meaning of the Law and the Rules. 'Regulatory obligation or requirement' is relevantly defined in section 2D(1)(b)(v) of the Law as including:

> *an obligation or requirement under … an Act of a participating jurisdiction, or any instrument made or issued under or for the purposes of that Act … that materially affects the provision, by a regulated network service provider, of electricity network services that are the subject of a distribution determination[.]*

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87 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-58.

88 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-59.

89 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-56.

90 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-63.

91 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-55 (footnote 62).

92 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 7-57 to 7-58.

93 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-57.

94 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-57.

The requirement to comply with EBAs constitutes a 'regulatory obligation or requirement' given the following:

- section 50 of the FW Act prohibits contravention of the terms of an EBA. This is an 'obligation or requirement' under the FW Act;
- the Commonwealth is a 'participating jurisdiction'[95] and thus the FW Act is 'an Act of a participating jurisdiction'; and
- the material degree to which EBA outcomes affect the provision of electricity network services follows from the fact that they affect the price at which, and the terms on which, those services can be provided. As is evident from the proportion of our expenditure that constitutes 'labour' expenditure, electricity distribution businesses are labour intensive. As discussed below, our EBAs impact on our dealings with a significant proportion of our employees and also affect our dealings with contractors, and thus it is clear that the requirement under the FW Act to comply with EBAs materially affects the provision of our electricity network services.

In its final determination regarding SA Power Networks, the AER took the view that an EBA has no effect on the provision of electricity network services on the basis that:[96]

- there is no necessary connection between the terms of an EBA and the nature, quality or quantity of network services supplied by a distributor; and
- an EBA is not required to provide electricity network services and a distributor may arrange labour on many bases that do not involve an EBA.

The AER's conclusion that an obligation or requirement must have a connection to the 'nature, quality or quantity of network services' in order to constitute a 'regulatory obligation or requirement' within the meaning of the Law and the Rules cannot be sustained. The AER's construction is not reasonably open on the words of the Law's definition of 'regulatory obligation or requirement'. It is dependent on 'reading in' to the Law words that do not appear in section 2D (i.e. the words 'nature, quality or quantity'), in circumstances where there is no basis for concluding that this is necessary to achieve the legislative intent. Further, the AER's construction would lead to a result that is manifestly absurd and unreasonable. Obligations requiring distributors to clear vegetation around powerlines and meet bushfire safety standards, for example, would fall outside of the definition on the basis that those obligations are not concerned with the 'nature, quality or quantity' of electricity network services, such that forecast expenditure need not compensate a distributor for the costs of complying with those obligations. This is manifestly absurd and unreasonable, and cannot have been the intention of the legislature.

The AER's second reason proceeds on an assumption that a distributor can function without EBAs. This assumption has no basis in reality and is erroneous. Against the background of the highly unionised nature of the electricity distribution industry, the suggestion that a distributor could manage its employees without the use of EBAs lacks commercial realism. The negotiation of EBAs is favoured by unions as a means of securing more favourable terms of employment, and pursuant to the legal framework established by the FW Act they have the means of compelling the negotiation of EBAs by electricity distributors, specifically through protected industrial action under Part 3-3 of that Act or by seeking a majority support determination from the Fair Work Commission under section 236 of that Act requiring a distributor to negotiate an EBA. These issues were explored in the advice of DLA Piper attached to our regulatory proposal.[97] In response to the AER's preliminary determination,

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95 Section 5 of the Law provides that the Commonwealth is a participating jurisdiction if there is in force, as part of the law of that jurisdiction, a law that corresponds to Part 2 of the *National Electricity (South Australia) Act 1996* (SA). Section 6 of the *Australian Energy Market Act 2004* (Cth) applies *National Electricity (South Australia) Act 1996* (SA) as a law of the Commonwealth.

96 AER, *Final decision, SA Power Networks determination 2015-16 to 2019-20*, October 2015, p. 7-45.

97 CP PUBLIC ATT 7.11 - DLA Piper, *Enterprise bargaining agreements*, March 2015.

we engaged DLA Piper to consider whether we would be likely to enter into new EBAs in the 2016–2020 regulatory control period. DLA Piper's *Legal opinion* is attached. DLA Piper concludes that it would be very difficult for us to resist entering into new EBAs at the expiry of the current ones.[98]

Not surprisingly, therefore, EBAs are an integral part of managing labour in electricity distribution businesses. All distributors in the national electricity market except one have EBAs in place,[99] and these businesses have a high proportion of employees employed under EBAs (in the main, over 75 per cent but up to 95 per cent).[100] The one distributor that does not have an EBA is UED. This is because UED has outsourced its network operations.[101] However, each of UED's network operators (Tenix Australia Pty Ltd and ZNX Pty Ltd) have EBAs for electrical work in Victoria and the wage growth rates in those EBAs are comparable to the wage growth rates in the EBAs of the Victorian distributors.[102]

For these reasons, it is impracticable and commercially infeasible to operate an electricity distribution business without EBAs in place, and which would necessarily cover a significant proportion of labour.

For completeness, we note that while the AER concluded in its final determination regarding SA Power Networks that an EBA is not a 'regulatory obligation or requirement' as defined in section 2D of the Law, the AER's analysis in that decision was misdirected. In particular, the AER did not consider the direct obligation in section 50 of the FW Act, but rather, assessed whether an EBA itself is an instrument made under or for the purposes of the FW Act and thus comprises a 'regulatory obligation or requirement' within the meaning of the Law. For the reasons outlined above, the obligation in the FW Act itself meets the definition of 'regulatory obligation or requirement'.

However, even if the AER's approach to the analysis were correct (i.e. that what must be considered is whether an EBA is an instrument made under or for the purposes of the FW Act), the AER erred in concluding that it is not. This is because:

- an EBA is an instrument made under or for the purposes of the FW Act. The AER takes the view that, because an EBA is made when a majority of employees vote to approve the EBA and thus it is an agreement between the enterprise and employees (which is subsequently regulated by the FW Act), it is not an 'instrument made or issued under' the FW Act.[103] However, in reaching this conclusion, the AER disregards the language of section 2D(1)(b)(v) of the Law, which expressly provides that an obligation or requirement under 'an instrument made or issued … for the purposes of' the FW Act is a 'regulatory obligation or requirement' for the purposes of the Law. Even if the AER is correct in concluding that an EBA is properly characterised as an agreement, it does not follow that an EBA is not made for the purposes of the FW Act. To the contrary, an EBA is made for the purposes of that Act and the obligations and requirements imposed by an EBA are therefore 'regulatory obligations or requirements' for the purposes of the Law; and

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98 DLA Piper, *Legal opinion*, 16 December 2015.

99 DAE, *NSW Distribution Network Service Providers Labour Analysis, Final Addendum to 2014 Report*, 28 April 2015, pp. 17-18.

100 DAE, *NSW Distribution Network Service Providers Labour Analysis, Final Addendum to 2014 Report*, 28 April 2015, pp. 17-18. Contrary to the indication by DAE, we note that approximately 56 of our employees are engaged and paid under the terms and conditions of our existing EBAs and, as discussed further below, even more are covered such that they cannot be disadvantaged by the terms and conditions in their individual employment agreements relative to the EBAs. Other distributors have even higher levels of employees paid in accordance with their EBAs. For example, around 95 per cent of SA Power Networks' employees are bound by its Utilities Management Pty Ltd Enterprise Agreement 2014: SA Power Networks, *Revised Regulatory Proposal 2015-20*, 3 July 2015, p. 210.

101 UED, *2016 to 2020 Regulatory Proposal*, 30 April 2015, pp. 53-54.

102 *Tenix Australia Pty Ltd and ETU power construction maintenance enterprise agreement 2013–2016, 15 October 2014, clause 16.1*; *ZNX Pty Ltd - ETU Victorian electricity enterprise agreement 2013, 17 June 2014, clause 8.1*; and *ZNX Victorian staff enterprise agreement 2014, 3 February 2015, clause 28.2.*

103 See, for example, AER, *Final decision, SA Power Networks determination 2015-16 to 2019-20*, October 2015, p. 7-45.

- the AER's views are also contrary to Full Federal Court decisions as to the nature of the obligation to comply with an EBA. The Full Federal Court of Australia has stated that EBAs:
  - have statutory force and, as statutory instruments, have more formality and greater consequence than any contract could have;[104]
  - are more than agreements in the way of contracts, being specific instruments made under a detailed regime and enforceable only as provided by the FW Act;[105] and
  - have more of a legislative than contractual character.[106]

Against such a background, the AER's conclusion is clearly erroneous.

The Rules require expenditure forecasts to include the expenditure required in order to achieve compliance with all applicable regulatory obligations or requirements.[107] Given the obligation to comply with an EBA is a 'regulatory obligation or requirement' within the meaning of section 2D of the Law, these clauses require the inclusion of expenditure to allow distributors to comply with an EBA.

Further, the AER is required to take into account the revenue and pricing principles in section 7A of the Law,[108] which include that a distributor should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in complying with a regulatory obligation or requirement.

In addition, given our existing EBAs apply for part of the 2016–2020 regulatory control period, and it is inevitable that we will enter into new EBAs during the period, it is clear that, in order for any expenditure forecast to reasonably reflect a realistic expectation of the cost inputs required to achieve the expenditure objectives (as required by clauses 6.5.6(c)(3) and 6.5.7(c)(3) of the Rules), the likely labour costs under and in light of EBAs, both existing and likely, must be reflected in those forecasts.

The AER is therefore required to allow expenditure so as to permit compliance with both our current EBAs and EBAs likely to be entered for the period beyond the EBAs presently in force. The AER cannot simply put to one side the legal obligations with which we are required to comply.

<u>Our EBA-based forecasts are the most representative of our prudent and efficient labour price growth</u>

Our current EBA outcomes are prudent and efficient

Irrespective of whether the AER concludes that the requirement to comply with our EBAs is a 'regulatory obligation or requirement' (and thus must be reflected in our expenditure forecasts), we have demonstrated that our EBA outcomes are prudent and efficient.

In our regulatory proposal, we included detailed information demonstrating the efficiency of our EBA negotiations, including our willingness to take a strong position in these negotiations, our refusal to concede on all union claims and commitment to pursuing changes favourable to our business.[109]

The AER failed to investigate this information in making its preliminary determination. Such a failure is akin to the error into which the AER fell in failing to investigate the circumstances in which Ergon Energy's 2008–2011 Union

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[104] *Australian Industry Group v Fair Work Australia* [2012] FCAFC 108 at [69] to [73].

[105] *Toyota Motor Corporation Australia Limited v Marmara* (2014) 222 FCR 152 at [97].

[106] *Toyota Motor Corporation Australia Limited v Marmara* (2014) 222 FCR 152 at [88] to [89]; *Teys Australia Beenleigh Pty Ltd v Australasian Meat Industry Employees Union* [2015] 317 ALR 636 at [92].

[107] NER, clause 6.5.6(a). Clause 6.5.7(a) is the analogous provision in respect of capital expenditure.

[108] NEL, section 16(2).

[109] CitiPower, *Regulatory Proposal 2016–2020*, chapter 7, section 7.1.2.

Collective Agreement had been negotiated (on which it proposed labour cost escalators for its 2010–2015 regulatory control period).[110] In that instance, the Australian Competition Tribunal (**Tribunal**) accepted the nominal figure derived from Ergon Energy's 2008–2011 Union Collective Agreement as the basis for calculating the internal labour rate escalator for 2011 (being the first year of its regulatory control period).[111]

In addition to demonstrating the rigour with which our EBA negotiations were undertaken, it can be shown that the resulting wage rate increases in those EBAs are prudent and efficient. While we maintain it is not appropriate to consider provisions of an EBA in isolation (rather, the EBA should be considered as an overall package), it can be seen from the table below that the wage growth rates in our current EBAs are in line with the wage growth rates in the EBAs of other Victorian electricity network service providers in force in our 2014 base year.[112]

Table 4.4 Comparison of EBA wage growth rates (nominal)

	2012	2013	2014	2015	2016
Our CEPU EBA[113]	-	-	4.55%	4.55%	4.55%
Our ASU/APESMA/NUW EBA[114]	-	-	4.50%	4.50%	4.50%
SPI PowerNet & SPI Electricity - ASU/APESMA enterprise agreement 2013[115]	-	4.50%	4.50%	4.50%	-
SPI PowerNet & SPI Electricity - ETU enterprise agreement 2013[116]	-	4.50% (6.50% for the year)[117]	4.50%	4.50%	-
Jemena Asset Management enterprise agreement (VIC) 2013[118]	4.00%	4.00%	4.00%	-	-
Jemena Asset Management - ETU Victorian electricity enterprise agreement 2013[119]	-	4.00%	4.00%	4.00%	-

Source: CitiPower

110 *Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No. 3)* [2010] ACompT 11.

111 *Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No. 3)* [2010] ACompT 11 at [58]-[60].

112 This is examined, for instance, in the DLA Piper's advice provided with our regulatory proposal: CP PUBLIC ATT 7.11 - DLA Piper, *Enterprise bargaining agreements*, March 2015.

113 CEPU EBA, clause 16. Pay increases under the CEPU EBA are given effect bi-annually, on 6 May 2014, 1 August 2014, 1 January 2015, 1 July 2015, 1 January 2016 and 1 July 2016. We have not accounted for the impact of compounding.

114 ASU/APESMA/NUW EBA, clause 16. Pay increases are effective from the beginning of the first pay period on or after 1 July in the relevant year.

115 *SPI PowerNet & SPI Electricity - ASU/APESMA enterprise agreement 2013*, 14 October 2013, clause 29. Pay increases are effective: in 2013, from the date the agreement came into operation; and in 2014 and 2015, from 1 October in each year.

116 *SPI PowerNet & SPI Electricity - ETU enterprise agreement 2013*, 30 October 2013, clause 26. Pay increases under this EBA are effective from 1 September in each year.

117 The increase negotiated under the 2013 EBA was in addition to a 2 per cent increase on 1 March 2013 as provided for in the prior EBA: *SPI PowerNet & SPI Electricity - ETU enterprise agreement 2010-13*, 8 November 2010, clause 26.1. The value of 6.5 per cent does not take into account the impact of compounding.

118 *Jemena Asset Management enterprise agreement (VIC) 2013*, 23 August 2013, clause 25.5(a). Pay increases under this EBA are effective on 31 December each year.

119 *Jemena Asset Management - ETU Victorian electricity enterprise agreement 2013*, 12 June 2014, clause 8.1. Pay increases under this EBA are effective on 1 September each year.

In addition, a review of the EBAs of the other efficient distributor (SA Power Networks) shows that our EBA wage growth rates are also in line with the EBAs of that distributor.[120]

Further, as demonstrated by Frontier Economics, our EBA wage growth rates are in line with average EBA outcomes for privately owned electricity network businesses in Australia.[121]

Finally, and in any event, the AER's own benchmarking indicates that we are operating efficiently, and on some models are the best performer.[122] Indeed, the AER has called CitiPower the 'frontier' firm, being the best performer on the basis of its preferred model for assessing efficiency.[123] The AER relies on this outcome both for the purposes of applying a revealed cost approach to forecast our operating expenditure for 2016–2020[124] and in rejecting and substituting operating expenditure forecasts for less efficient distributors.[125] In doing so, the AER has accepted the efficiency of our total labour expenditure, which necessarily involves acceptance of the efficiency of our labour force practices and EBA outcomes.

If the AER proceeds, in revoking and substituting our 2016–2020 distribution determination, to determine operating expenditure based on our (efficient) historic costs, but to disallow the labour price growth rates underpinning that overall expenditure, the AER would be internally inconsistent and its approach would amount to cherry picking. These matters are discussed in turn below.

The AER's approach is internally inconsistent in that, while the AER recognises the efficiency of our total operating expenditure and thus EBA outcomes in adopting a revealed cost approach on the one hand, the AER fails to allow for the real price growth that flows from those outcomes on the other. The AER fails to recognise that enterprise bargaining involves reaching agreement on an overall package of terms and conditions, with various trade-offs between various clauses.[126] The AER has expressly acknowledged in other decisions, for example, that our EBAs allow greater workforce flexibility than is achieved in New South Wales, and that the gains through outsourcing realised by Victorian distributors is one of the reasons for our efficiency relative to New South Wales distributors.[127] DAE, in its report for the AER in respect of New South Wales distributors, contrasted, for example, the challenges faced by those distributors in respect of outsourcing under restrictive provisions in their EBAs with the EBA provisions of the Victorian distributors and their operation.[128]

The AER's approach is cherry picking in that the AER has assessed our base year operating expenditure as efficient, but then argued that the conditions that gave rise to that base year operating expenditure are inefficient. By honing in on wage price growth and failing to allow for the real price growth that flows from the arrangements underpinning our (efficient) base year operating expenditure, the AER produces systematically

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120 *Utilities Management Pty Ltd Enterprise Agreement 2014*, 19 May 2014, clause 8.

121 CP PUBLIC ATT 7.3 - Frontier, *Labour cost escalation forecasts using enterprise bargaining agreements*, February 2015, p. 15, Figure 6. For the reasons described further below, Frontier Economics concluded that the appropriate point of comparison is all privately owned electricity network businesses (that is, it is appropriate to exclude publicly owned electricity network businesses from the comparison).

122 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 7-23, 7-31 to 7-37. See also: *AER, Annual benchmarking report, Electricity distribution network service providers*, November 2015, p. 13.

123 See, for example, AER, *Final decision Ausgrid distribution determination 2015-16 to 2018-19*, April 2015, p. 7-54.

124 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-31.

125 See, for example, AER, *Final decision, Ausgrid distribution determination 2015-16 to 2018-19*, April 2015, pp. 7-54, 7-61 to 7-62.

126 This point was expressly made in advice from DLA Piper accompanying our regulatory proposal: CP PUBLIC ATT 7.11 - DLA Piper, *Enterprise bargaining agreements*, 26 March 2015 at [35]-[37].

127 See, for example, AER, *Final decision, Ausgrid distribution determination 2015-16 to 2018-19*, April 2015, p. 7-154. In making this finding, the AER draws on analysis by DAE: DAE, *NSW distribution network service providers labour analysis, Final addendum to 2014 report*, 28 April 2015, pp. 19-20.

128 DAE, *NSW distribution network service providers labour analysis, Final addendum to 2014 report*, 28 April 2015, pp. 19-20.

biased estimates. This effect is compounded given the significant proportion of operating expenditure that is labour related.

The AER's approach cannot be reconciled with its own observations about the undesirability of adopting bottom-up forecasts for particular categories of operating expenditure, here labour expenditure, in circumstances where a revealed cost approach is otherwise applied to forecast operating expenditure.

In its final determination regarding SA Power Networks, the AER stated that it is not efficient for a prudent firm to pay more than the EGWW industry market rate for its labour without improving productivity.[129] The AER reasoned that otherwise the marginal cost for each unit of labour exceeds the market rate and SA Power Networks had not identified any benefits to consumers that would flow from its EBA that would offset its labour price increases. For the reasons discussed further below, the EGWW WPI is not representative of our labour price growth rates.

Our forecasts based on historic EBA outcomes are prudent and efficient

As discussed further below, Frontier Economics has demonstrated that EBA wage growth rates across the electricity network industry have been relatively stable over the past ten years, far more stable than EGWW WPI and Australian all industries WPI over the same period.[130] A comparison of historical EBA wage growth rates of Australia privately owned electricity networks and DAE's forecasts of the EGWW WPI shows that DAE's EGWW WPI based forecasts of labour growth were initially well above EBA rates for privately owned electricity networks, the forecasts EGWW WPI have fallen significantly since then.[131] The stability of EBA wage growth rates is evident irrespective of the choice of historical averaging period (which would not be the case if EBA wage growth rates were variable over time).[132]

In circumstances where EBA wage growth rates have been stable even where there has been considerable fluctuation in the EGWW WPI (both at the Victorian and Australia wide level) and the Australian all industries WPI, but no change to the factors resulting in such stability (described further below), there is no basis for assuming that the stability in EBA wage growth rates will not continue in the 2016–2020 regulatory control period.

We engaged Frontier Economics to update its EBA-based forecasts for the 2016–2020 regulatory control period to reflect any relevant EBAs approved subsequent to its February 2015 report submitted with our regulatory proposal. Frontier Economics identified one such EBA[133] and we have updated our labour price growth forecasts to reflect this.

Frontier Economics sets out four forecasts of real price growth for 2016–2020 based on:[134]

- a five year average for all Victorian networks;
- a ten year average for all Victorian networks;
- a five year average for all Australian privately owned networks; and

[129] AER, *Final decision, SA Power Networks determination 2015-16 to 2019-20*, October 2015, p. 7-44.

[130] CP PUBLIC ATT 7.3 - Frontier Economics, *Labour cost escalation forecasts using enterprise bargaining agreements*, February 2015, pp. 13-16; DAE, *Forecast growth in labour costs in NEM regions of Australia*, 15 June 2015, pp. 30, 33. See also: CitiPower, *Regulatory Proposal 2016–2020*, April 2015, pp. 72-73.

[131] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 20-21.

[132] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 26-27.

[133] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 3.

[134] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 4.

- a ten year average for all Australian privately owned networks.

Of these forecasts, we adopted the lowest forecast (being the five year average for all Australian privately owned networks). This means that our estimates are likely to be conservative. This is particularly the case given the most relevant outcomes for the purposes of determining our prudent and efficient costs are those in Victoria. That there are differences in labour market conditions unique to Victoria is accepted by the AER given it uses forecasts of the EGWW WPI for Victoria to forecast labour price growth.

In its report submitted with this revised regulatory proposal, Frontier Economics also demonstrates that using historical average EBA outcomes to predict future EBA outcomes is an exceptionally accurate method of forecasting wage growth rates.[135]

EBA-based forecasts are more representative of labour price growth rates than EGWW WPI forecasts

The discussion above demonstrates that our EBA-based forecasts are prudent and efficient. We show below that EBA-based forecasts are the most representative of our expected labour price growth in the 2016–2020 regulatory control period (and certainly more representative than the EGWW WPI used by the AER).

EBAs are an integral part of managing labour in our business. Our payroll records indicate that as at 30 November 2011, 56 per cent of our employees are currently employed under our existing EBAs. As described above, other distributors have an even higher proportion of employees on EBAs (in the main over 75 per cent, but up to 95 per cent). This can be contrasted with the EGWW industry more broadly, in which the percentage of workers covered by an EBA in the year to September 2014 in Victoria was just over 25 per cent.[136]

In addition, the wage rates in EBAs have broader applicability to our labour force than employees said to be employed under the EBAs. This is because additional employees are engaged and paid under 'Employment Agreements', which (under the terms of our EBAs and the FW Act) must offer terms and conditions that do not disadvantage that employee, relative to the EBA applicable to that employee.

Clause 14 of each of the CEPU EBA and the ASU/APESMA/NUW EBA provides that employees may elect to work pursuant to the terms of an 'Employment Agreement'. The clause provides that employees are not to be disadvantaged by entering into such agreements (including that there must be no diminution in wages) and may, at any time, revert to being paid in accordance with the relevant EBA.

It is difficult to say with any certainty the precise proportion of labour that may be classified as being employed under 'Employment Agreements' for the purposes of clause 14 of each of our existing EBAs. The unions are likely to take the view that all employees not currently paid under our existing EBAs except senior management (that is, 97 per cent of our workforce) are on 'Employment Agreements'. In DLA Piper's *Legal opinion* attached to this revised regulatory proposal, DLA Piper indicates that, given clause 14 of each of our existing EBAs and the broad nature of the EBAs, it is likely that a significant proportion of the total workforce would be either paid under the EBAs or otherwise in accordance with individual 'Employment Agreements' as provided for under our existing EBAs.[137]

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135 Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 31-34.

136 DAE, *Forecast growth in labour costs in NEM regions of Australia*, 23 February 2015, p. 45. While the AER sought an updated report from DAE for the purposes of the preliminary determination, this report cited EBA coverage only at the national level (namely that around one third of workers in the EGWW industry, nationally, are employed under EBAs): DAE, *Forecast growth in labour costs in NEM regions of Australia*, 15 June 2015, p. 44. While the date of the data cited by DAE in its report for the purposes of the preliminary determination is not clear, given the prior figures cited by DAE show that EBA coverage is significantly higher in Queensland, New South Wales and South Australia than Victoria, it can be expected that EBA coverage in Victoria is lower than the national average cited by DAE in its June 2015 report.

137 DLA Piper, *Legal opinion*, 16 December 2015 at [9].

Further, in addition to impacting on a significant proportion of employees, our EBAs impact on our outsourcing arrangements as contractors benefit from a parity condition in the CEPU EBA, which means that contractors must be paid at least the negotiated EBA wage rates.

Clause 51.1 of the CEPU EBA requires contractors to apply wages and conditions that are no less favourable than those contained in the 'Reference Document' and that if there is a reasonable and genuine basis for a conclusion that a contractor is not meeting the parity requirement, we will cease to engage that contractor. The meaning of 'Reference Document' in clause 51.1 was the subject of a confidential *Memorandum of understanding between CitiPower, Powercor and the CEPU*.[138] This document shows that the wage growth rates in the 'Reference Document' referred to in clause 51.1 are the same as those under the CEPU EBA.

This provision imposes limitations on the labour prices incurred by third party contractors, and thus the contract prices facing us where it applies.

Clause 47 of the ASU/APESMA/NUW EBA limits the circumstances in which work can be contracted out to third parties and requires the agreement of the unions to do so. As observed in the DLA Piper *Legal opinion* attached to this revised regulatory proposal, this means the ability to generate lower cost outcomes by the use of contractors is potentially more limited.[139]

Two implications flow from the above.

First, the discussion demonstrates that EBA-based labour price growth forecasts are more representative of our labour price growth than EGWW WPI, including because those wage rates apply to a larger proportion of our employees than are currently paid in accordance with our EBAs.

Secondly, the parity provisions in our CEPU EBA means our EBA wage growth rates impact on the labour prices paid by our contractors providing field services and thus our position with respect to contracted labour. This second impact is particularly relevant if the AER determines (as it did in its preliminary determination) to apply a 'labour' price growth rate drawing on only one measure. The discussion above indicates that any such single measure should be EBA-based forecasts, rather than the EGWW WPI.

Implicit in the AER's preliminary determination is a presumption that, used as the sole measure of labour price growth, forecasts of the EGWW WPI are representative of labour price growth rates for electricity distributors. This is not the case, and is contrary to the AER's own assessment of the degree to which the EGWW WPI is representative of the wage rates facing electricity distributors.

In the AER's preliminary determination, the AER suggests that the EGWW industry is an appropriate comparison point because the electricity industry makes up a majority of the EGWW industry.[140] There are a number of flaws in the AER's reasoning.

The high point for the case in support of the contention that the EGWW WPI is representative of our labour price growth rates is a statement by DAE that '*electricity labour is a large component of the utilities sector and therefore it would have a notable impact on the WPI series*'.[141] In its preliminary decision regarding SA Power Networks, the AER specified that electricity workers make up 56.5 per cent of the EGWW industry.[142] As noted by Frontier Economics, even if distributors represented 56.5 per cent of the EGWW industry, that would still leave a

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138 *Memorandum of understanding between CitiPower, Powercor and the CEPU, appendix A of the ETU powerline enterprise agreement 2013–2016 annexed to that memorandum.*

139 DLA Piper, *Legal opinion*, 16 December 2015 at [16].

140 AER, *Preliminary decision CitiPower distribution determination 2016–20*, October 2015, p. 7-55 (footnote 62).

141 AER, *Preliminary decision CitiPower distribution determination 2016–20*, October 2015, p. 7-55 (footnote 62).

142 AER, *Final decision, SA Power Networks determination 2015–16 to 2019–20*, October 2015, p. 7-43.

very substantial portion of the EGWW industry (43.5 per cent) that can be driven by other industries.[143] A conclusion that the electricity supply groups within the EGWW industry have a '*notable impact*' on the EGWW WPI does not logically lead to the conclusion that the EGWW WPI is representative of the labour price growth rates facing electricity distributors.

The AER fails to acknowledge that the electricity sector represented in the EGWW industry sample includes electricity businesses other than distributors, namely transmission, generation and retail businesses. These businesses bear few similarities to electricity distributors, particularly in terms of labour skill requirements. While it is not possible to determine the weight given to electricity distributors within the EGWW WPI (this information is not released by the ABS), as noted by Frontier Economics, if electricity distributors were represented highly within the EGWW WPI, movements in the EGWW WPI would reasonably track movements in the EBA wage growth rates of electricity distributors over time.[144] This is not the case.[145] Accordingly, we do not consider that the AER's assertion that electricity labour would have a '*notable*' impact on the WPI series is evidence that the EGWW WPI is representative of our labour price growth rate.

In its February report submitted with our regulatory proposal, Frontier Economics concluded that the occupation mix (that is, the type of labour required by the types of businesses) varies considerably within the EGWW industry. Frontier Economics reiterates this finding in the report submitted with this revised regulatory proposal.[146] The analysis conducted by Frontier Economics reveals that the occupation mix of EGWW businesses other than electricity distributors (even those businesses in the electricity industry) is generally very different to the labour mix of electricity distributors, which Frontier Economics concludes suggests that the EGWW WPI is very unlikely to be representative of the labour costs of electricity distributors and thus there is very strong evidence that the AER's assumption about the suitability of the EGWW industry as a benchmark for an efficient electricity distributor is inappropriate.[147] This is demonstrated in the following figure, extracted from the Frontier Economics report.

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[143] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 6.

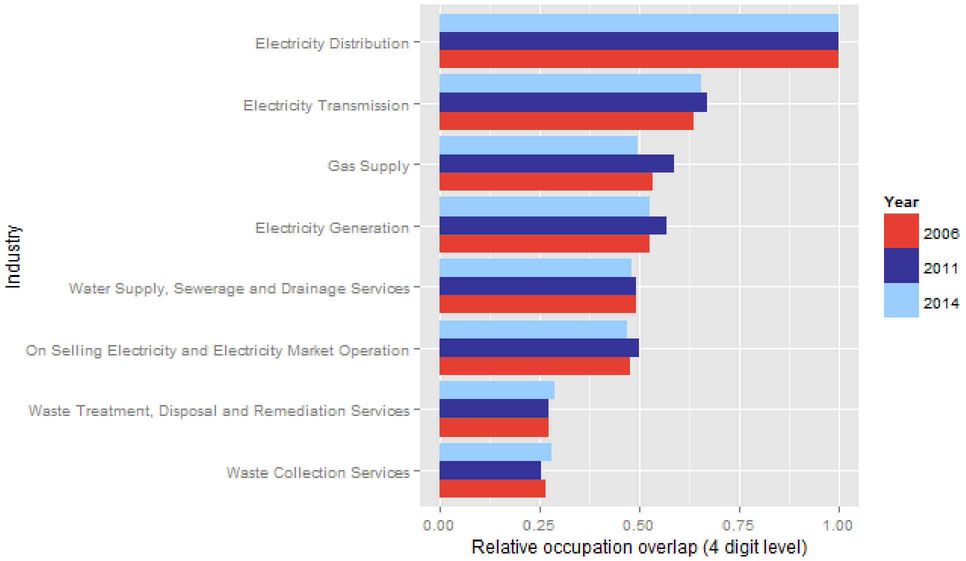
[144] CP PUBLIC ATT 7.3 - Frontier Economics, *Labour cost escalation forecasts using enterprise bargaining agreements*, February 2015, p. 5.

[145] CP PUBLIC ATT 7.3 - Frontier Economics, *Labour cost escalation forecasts using enterprise bargaining agreements*, February 2015, pp. 13-16.

[146] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 6-9.

[147] CP PUBLIC ATT 7.3 - Frontier Economics, *Labour cost escalation forecasts using enterprise bargaining agreements*, February 2015, p. 12.

Figure 4.1 Occupation overlap in the EGWW industry for 2006, 2011 and 2014



Source: Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 7.

The AER's preliminary determination is inconsistent with prior decisions in which the AER concedes the sampling inaccuracy in using the EGWW WPI. The imperfect nature of the EGWW WPI for the purposes of forecasting labour price growth for electricity distributors is clearly expressed by the AER in its preliminary decision regarding SA Power Networks in which the AER noted:[148]

> *The choice of labour price measure should reflect the annual change in labour price for electricity distribution workers. Neither a private service provider's [EBA] nor a utilities industry wide labour price is a perfect measure of the electricity industry's labour price.*
>
> *…*
>
> *[O]ur industry wide measure is a broader than ideal measure of the labour price for electricity workers, because it includes workers from other utilities, as well as the electricity industry. Although electricity workers make up a majority of the EGWWS, the change in the labour price in other industries can influence the labour price.*

In conjunction with SA Power Networks, we engaged NERA (UK) to review the AER's application of the EGWW WPI to labour price growth. NERA (UK)'s report, *Expert report on the allowed rate of change in SA Power Networks' expenditure due to expected inflation in labour costs*, is attached to this revised regulatory proposal.[149] NERA (UK) identified (among others) the following reasons why the EGWW WPI is less relevant to forecasting the costs of electricity distributors than EBA outcomes:[150]

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148 AER, *Final decision, SA Power Networks determination 2015–16 to 2019–20*, October 2015, pp. 7-51 to 7-52.

149 NERA (UK), *Expert report on the allowed rate of change in SA Power Networks' expenditure due to expected inflation in labour costs, 23 June 2015.*

150 NERA (UK), *Expert report on the allowed rate of change in SA Power Networks' expenditure due to expected inflation in labour costs, 23 June 2015.*

- whereas forecasts of labour costs based on EBAs focus on the specific labour costs faced by electricity distributors, the EGWW WPI covers workers from other utilities in addition to the electricity industry, and covers workers from the non-network side of the electricity sector (generation and retail), which bear few similarities to distribution networks; and
- to the extent some workers have skill sets that allow them to work across all utility industries, as is most likely to be the case for contractor labour, forecasts of EGWW WPI may reflect market trends that determine the cost of hiring contract labour for outsourced functions but are materially less relevant as a measure of in-house labour costs than EBAs.

Response to the reasoning in the AER's preliminary determination

The AER's complaints regarding the use of our EBA-based forecasts are irrelevant considerations against the background of the requirement to comply with EBAs being a 'regulatory obligation or requirement' within the meaning of the Law and the Rules. This is relevant both for the period during which our existing EBAs govern wage price growth and the period beyond this, when wage price growth will be the subject of EBAs entered into during the regulatory control period.

Additional reasons why the complaints levelled by the AER at our use of EBA-based forecasts of labour price growth are not sustainable are nonetheless outlined below.

The AER's 'hybrid forecasting method' concern is unfounded

The AER's description of our forecasting methodology as a '*hybrid forecasting method*' is a mischaracterisation of the approach adopted. The outcomes of our actual EBAs are known: no forecasting methodology is required in respect of those EBAs. The only unknown outcomes, in respect of which a forecast is required, are wage rates once the existing EBAs cease to have effect. This is the period over which we have proposed price growth rate forecasts for labour on the basis of Frontier Economics' EBA-based forecasts. Accordingly, there is a single forecasting methodology proposed for the 2016–2020 regulatory control period. In any event, it would be absurd to disregard the known outcomes of the actual EBAs and to instead adopt a less accurate forecast on the footing that this would avoid a hybrid forecasting method.

The AER's criticism is surprising in circumstances where it has itself recently used actual EBA outcomes for the period in which EBAs are on foot and wage rates forecast by consultants for the period beyond the expiry of those agreements. In particular:

- in its 2014 final decision regarding the transmission network of SP AusNet (now AusNet Services), the AER applied labour growth rates based on SP AusNet's most recent EBA outcomes until they expired and beyond that time the average of two EGWW WPI forecasts;[151] and
- in its 2012 final decision regarding the transmission network of Powerlink, the AER used the wage rate increases in Powerlink's 2008 and 2011 EBAs to forecast labour costs through to 2013-14 and forecast movements in the LPI to forecast the change in labour costs from 2014-15.[152]

This approach cannot be reconciled with the criticism the AER is now raising in respect of our proposed labour price growth rates.

In addition, as noted above, in *Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No. 3)* [2010] ACompT 11, the Tribunal adopted labour price growth rates based on actual EBA outcomes for the period until the EBA expired and thereafter labour price growth rates based on forecasts prepared by an economic

151 AER, *Final decision, SP AusNet transmission determination 2014-15 to 2016-17*, January 2014, p. 65.

152 AER, *Final decision, Powerlink transmission determination 2012-13 to 2016-17*, April 2012, p. 66.

consultant.[153] There is no evidence from the Tribunal's decision that the AER raised any concerns as to the Tribunal adopting a 'hybrid forecasting methodology' and the Tribunal evidently did not hold such a view.

The AER's conclusion that using both actual EBA outcomes and forecast EBA outcomes based on industry averages would not result in expenditure forecasts consistent with the expenditure criteria because individual EBA outcomes reflect the market conditions at the time the EBA was negotiated fails to reflect the stability in EBA outcomes over time, which has persisted irrespective of changes in labour market conditions. The stability of EBA wage price increases was discussed in the preceding section, and the irrelevance of labour market conditions to EBA wage negotiations is explained in more detail in the following section. The EBA wage growth rates do not generally deviate from the average of Australian privately owned networks and thus the concerns raised by the AER have no basis.

AER's conclusions based on current broader labour market conditions are erroneous

The AER's conclusion that forecasts based on our current and other historical EBA wage rates are too high and do not reflect market conditions likely to prevail in the 2016–2020 regulatory control period given the Australian all industries WPI and EGWW WPI are currently the lowest on record is in error.

The AER's conclusion is inconsistent with the evidence demonstrating that our current EBA wage growth rates, as well as our forecast EBA wage growth rates, are prudent and efficient. In concluding otherwise, the AER fails to take into account that EBA wage growth rates are stable over time, irrespective of fluctuations in both general and EGWW industry rates, which reflects a range of factors.

Current labour market conditions (whether industry specific or conditions in the economy more broadly) have no relevance to the requirement to comply with existing EBAs for the period over which we are required to comply with those EBAs. We have demonstrated above that the wage growth rates in our current EBAs are prudent and efficient.

Beyond that period, given EBAs will continue to be integral to managing labour, new EBAs will replace our existing EBAs. The wage growth rates in those EBAs will not reflect general labour market conditions or conditions in the broader EGWW industry. Rather, the wage growth rates will reflect the wage pressures specific to electricity distributors in Victoria. This is evidenced by the stability of historic average EBA wage growth rates over the past ten years, a period during which the EGWW WPI and general labour market conditions (at both the national and Victorian level) varied considerably.[154]

The reasons why EBA wage growth rates do not mirror the general labour market or the EGWW industry are numerous.

First, our workforce is highly specialised. High levels of training are required before any person can work on the network. For example, an apprentice lines worker undertakes four years of training involving a combination of trade school courses, in-house training and development courses, on-the-job skills learning under supervision and electronic job profiling. We incur approximately $230,000 per apprentice in training and associated costs to support the completion of the four year apprenticeship.[155] This translates to high costs associated with recruiting trained employees and training new employees, as well as an increased desirability of retaining existing staff. As shown in Frontier's analysis above, there is a low skills overlap between the requirements of electricity distributors and other industries in the EGWW sector.

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153 *Application by Ergon Energy Corporation Limited (Labour Cost Escalators) (No. 3)* [2010] ACompT 11.

154 CP PUBLIC ATT 7.3 - Frontier, *Labour cost escalation forecasts using enterprise bargaining agreements*, February 2015, pp. 13-16; DAE, *Forecast growth in labour costs in NEM regions of Australia*, 15 June 2015, pp. 30, 33. We note that the EGWW WPI was not reported separately for Victoria prior to 2009.

155 Includes costs of training programs and tools, accommodation and living away from home allowances. Excludes wages for labour time.

Secondly, there continues to be a demand for this skilled labour. We do not agree with the (unsubstantiated) submission of the Victorian Energy Consumer and User Alliance cited by the AER that the electricity network sector is in a major contraction phase (which it implies means we do not face real price increases).[156] As highlighted by Frontier Economics in its analysis of the AER's preliminary determination, both we and AEMO (whose forecasts are relied on by the AER) expect electricity consumption and peak demand to increase from current levels in the 2016–2020 regulatory control period.[157] Further, even if demand was declining, this would not necessarily result in declining labour. As explained by Frontier Economics, the electricity networks industry is characterised by very long-lived assets which cannot be switched 'on' and 'off' readily as in other industries and it is not feasible to reconfigure networks quickly in response to changing demand patterns, and we must continue to maintain assets in order to ensure safety and security of supply, which will in turn require a relatively stable workforce.[158]

In the 2016–2020 regulatory control period, we are expecting continued demand for skilled labour for a range of reasons, including increased capital expenditure driven by new connections and population growth, expenditure in response to regulatory changes in light of the Victorian Government's response to the Victorian Bushfires Royal Commission recommendations, as well as ongoing maintenance and capital replacement projects. This can be seen in the increases in total expenditure forecast over 2016–2020, in real terms, even without taking into account real price growth.

In considering the AER's complaint that EBA-based forecasts of labour price growth do not account for current labour market conditions, Frontier Economics notes that the AER implies that labour market conditions faced by distributors are expected to change significantly in the next regulatory control period but does not fully explain in its preliminary determination why it expects this to be the case.[159] Frontier Economics goes on to state that the implication the AER has made is that there are factors that forecasts of the EGWW WPI are accounting for, which the EBA-based forecasts fail to capture. While the AER does not indicate what these factors are, Frontier Economics identifies an explanation from DAE that these are:

- the overall economic outlook for Victoria;
- developments in the energy sector; and
- labour market developments in other industries.

Frontier Economics rejects the macroeconomic reasons cited by DAE for downward pressure on wage growth faced by Victorian distributors.[160] Neither DAE nor the AER have provided evidence that changes in the labour costs experienced by distributors will, over the short run, be sensitive to wider economic growth and unemployment; it is merely asserted.[161] Frontier Economics notes that while changes in output and unemployment at the aggregate level can influence employment and wage growth at the specific industry level, it is not necessarily the case that outcomes at the individual industry level should mirror what occurs in the broader economy.[162] To the contrary in this instance, the empirical evidence suggests that the rate of growth in

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156 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-59.

157 Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 28.

158 Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 28-29.

159 Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 23.

160 Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 25-27.

161 Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 25.

162 Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 25.

labour prices faced by distributors is not particularly sensitive to the macroeconomic drivers that DAE has identified.[163]

Frontier Economics also rejects the claim by DAE that energy policy reforms may reduce the labour requirements of distributors by lowering the need to expand infrastructure in the relatively near term period of the 2016–2020 regulatory control period. In doing so, Frontier Economics:[164]

- notes that DAE itself acknowledged that, if these effects do materialise, they would do so in the 'long term'; and
- highlights that the Australian Energy Market Commission, in making changes to the Rules relating to tariff reforms, indicated that the impact would be felt 'over the longer term'.

Further, Frontier Economics concludes that there is no evidence that there has been a decline in the demand for labour in response to declining demand.[165] Frontier Economics examined the average staffing levels reported by Victorian distributors in response to the CatA RINs issued by the AER, and these showed that there has been a generally increasing trend in average staffing levels for CitiPower, Powercor and all Victorian distributors combined between 2009 and 2014, the same period over which electricity consumption and peak demand have fallen.[166] Frontier Economics observes there is nothing to suggest that this growth in labour has been inefficient, indeed, based on data from 2006 to 2013, the AER assessed the Victorian distributors to be among the most efficient of the 13 distributors it regulates.[167]

Thirdly, further reasons why EBA wage growth rates do not mirror the EGWW industry or general labour market relate to the enterprise bargaining framework and the prevalence of union membership in our businesses. These matters were described in advice from DLA Piper submitted with our regulatory proposal. By way of summary:[168]

- there are a number of elements under the enterprise bargaining framework under the FW Act that allows unions to extract favourable outcomes and unions in the power industry (particularly the CEPU) have become skilled at using these;
- the electricity industry is highly unionised and thus the CEPU has a virtual monopoly over electrical employee labour supply which allows it to extract not only higher wages but better terms and conditions than in many other industries; and
- given we supply an essential service, interruptions to supply give rise to a greater risk of legal and financial consequences compared with many other industries and unions exploit this vulnerability.

DLA Piper concludes in the *Legal opinion* submitted with this revised regulatory proposal, that these issues make it difficult for distributors to resist EBA outcomes similar to previous ones.[169]

Wage negotiations of publicly owned electricity networks will not impact on our future EBA outcomes in 2016–2020

In responding to Frontier Economics' view that public sector employers face different pressures and constraints to private sector employers, particularly during periods of fiscal restraint, which can result in different labour cost

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[163] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 25-26.

[164] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 27-28.

[165] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 29.

[166] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 29.

[167] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 29.

[168] CP PUBLIC ATT 7.11- DLA Piper, *Enterprise Bargaining Agreements*, 26 March 2015.

[169] DLA Piper, *Legal opinion*, 16 December 2015 at [27].

outcomes, particularly over the short to medium term, the AER stated in its preliminary determination that while different labour cost outcomes between publicly and privately owned networks may occur over the short to medium term, these differences cannot persist indefinitely. More workers employed by publicly owned distributors will seek to move to privately owned distributors, while fewer seek to move the other way, which will impact on the supply and demand for labour and the outcome of the wage negotiations.[170]

In considering the AER's conclusions, Frontier Economics identifies two key errors:[171]

- first, it was never Frontier Economics' claim that the higher wage growth rates in the EBAs of privately owned networks would 'persist indefinitely'. Rather, the observation concerning the gap between public and private sector wage growth rates was particular to the 'short to medium term', which would include the 2016–2020 regulatory control period;
- secondly, while the gap between public and private sector wage growth rates may close eventually, the AER overstates the mobility of labour required to equalise pay rates. Frontier Economics considers that it seems unrealistic to assume the gap will close in the 2016–2020 regulatory control period because:
  - there are no publicly owned electricity networks in Victoria. This means that migration of workers from publicly owned networks to privately owned networks would have to occur between States and large-scale migration of that kind seems unlikely; and
  - the average gap in annual pay rate increases between those employed by publicly owned networks and privately owned networks over the 2012 to 2016 period is 1.25 percentage points. It seems unrealistic that a pay rate gap of this sort would induce mass movement of electricity network workers, particularly if that involved relocating interstate.

The AER's assumption that the wage negotiations of publicly owned electricity networks will impact on the wage growth rates in our EBAs also fails to take into account that the terms and conditions of EBAs must be considered as an overall package. That is the wage growth rates in those EBAs cannot be considered in isolation from the overall level of wages in the EBA and the other benefits included (or excluded) as part of the negotiation.

We note for completeness that while the AER states that Australian EGWW WPI increases are comparable to the EBA wage increases for electricity network service providers when public sector EBAs are included,[172] the basis for the AER's assertion is unclear. The AER does not indicate the basis on which it drew this conclusion. Contrary to the conclusion of the AER, analysis by Frontier Economics indicates that there is still a material divergence between EBA rates and the EGWW WPI, even if the EBA outcomes of publicly-owned networks are included in the analysis. Frontier Economics found that in 2013-2014, the average EBA wage growth rate (measured on a financial year basis) for all electricity networks in Australia (i.e. both privately-owned and publicly-owned networks) was 3.6 per cent, compared to the rate of change in the national EGWW WPI over that period of 3.2 per cent.[173] In any event, given the flaws that Frontier Economics has highlighted with the AER's suggestion that wage outcomes for publicly owned networks can impact on wage outcomes for privately owned networks, the AER's conclusion that Australian EGWW WPI wage increases are comparable to the EBAs for electricity network service providers when public sector EBAs are included has no bearing on the labour price growth rates that should be adopted for our business for the purpose of determining expenditure forecasts required to achieve the expenditure objectives and reasonably reflect the expenditure criteria.

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[170] AER, *Preliminary decision CitiPower distribution determination 2016–20*, October 2015, p. 7-59.

[171] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 35-36.

[172] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-59.

[173] Frontier Economics, *Review of AER's preliminary decision on labour escalation rates, A report prepared for SA Power Networks*, July 2015, p. 11.

Efficiency incentives are retained under our proposed EBA-based forecasts

The AER does not set out reasoning in support of its assertion that adopting wage rate increases in an individual firm's EBA would reduce the incentive to negotiate efficient wages. Rather, the AER cites assertions by DAE (that we will not have the incentive to move to the most productive workers and the long term efficient outcome) and the Victorian Energy Consumer and User Alliance (that distributors should not be allowed to continue to effectively treat inefficient EBA outcomes as a 'pass through').[174] These sources similarly fail to substantiate their assertions.

The AER's position fails to take into account that there can be no certainty as to the approach the AER will adopt in future regulatory review processes. As the AER stated in its distribution determination regarding Ausgrid, for example:[175]

> *[T]he service provider bears the consequence of imprudent or inefficient decisions, including those relating to cost inputs... When a service provider enters into an agreement of any kind, it does so in the full knowledge that the forecast will apply for five years, without any guarantee that the same or a similar forecast will be approved for the following five year period.*

There is also a further risk that the AER's approach may diverge from its prior approach if a distributor who was previously assessed to be efficient, is assessed as inefficient, and a change in approach is justified by reason of that inefficiency.

In any event, the AER's concern underplays the significance of the strong commercial incentives to outperform regulatory allowances, including those under the incentive based regime established by the Rules, whereby we are entitled to retain a share of the benefit of outperforming AER allowances under the EBSS and CESS. Further, the AER's conclusions are at odds with the AER's rationale in support of economic benchmarking. In its explanatory statement to its *Expenditure forecast assessment guideline*, the AER stated:[176]

> *[Economic benchmarking] creates reputational risk for NSPs, giving them a stronger incentive to adopt new technologies and business practices and to invest appropriately. Further, reporting productive efficiency accounting for all the factors of production provides information on dynamic efficiency. Using economic benchmarking in determinations also creates competitive pressures across NSPs, which will promote dynamic efficiency. If we forecast costs at the productively efficient level, NSPs that gain efficiencies through better management or innovation will retain a proportion of the efficiency gains.*

Irrespective of the basis on which labour price growth rates are determined by the AER, we have strong incentives to pursue efficiencies in operating expenditure. The AER does not explain why these efficiency incentives are eroded by our proposed approach.

While in the preliminary determination the AER does not appear to raise concerns regarding incentives if Frontier Economics' forecasts are adopted (the AER only raised concerns if an individual firm's EBA is used to forecast labour price growth), in its distribution determination regarding SA Power Networks, the AER rejected the use of forecasts based on an historical average of EBAs on the basis the decision may impact on negotiations. In particular, the AER stated:[177]

> *If we were to apply a historical average [EBA] for the years without an [EBA] then our decision may impact on the negotiations. This is because bargaining representatives may interpret this position as endorsing the*

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174 AER, *Preliminary decision CitiPower distribution determination 2016–20*, October 2015, p. 7-56.

175 AER, *Final decision, Ausgrid distribution determination 2015–16 to 2018–19*, April 2015, p. 7-87.

176 CP PUBLIC 9.4- AER, *Explanatory statement*, *Expenditure forecast assessment guideline,* November 2013, p. 126.

177 AER, *Final decision, SA Power Networks determination 2015–16 to 2019–20*, October 2015, p. 7-44.

historical average [EBA] rate as the appropriate wage increase. This may not be appropriate if one of the parties has been able to use its bargaining power to negotiate higher wage increases.

The AER's concern in this regard is unwarranted. As highlighted above, our incentives to negotiate as strongly as possible are preserved under our proposed approach. Unions will inevitably commence negotiations seeking wage rages far in excess of historical averages and we have strong incentives to reduce these to the greatest extent possible. For example, as noted in our regulatory proposal, the CEPU's starting point was a minimum annual increase in wages of eight percent.[178] Similarly, the ASU, APESMA and NUW sought an annual increase of six per cent.[179] Neither increase sought was accepted, rather, the final growth rate in the CEPU EBA is a bi-annual increase of 2.25 per cent (equivalent to 4.55 per cent per annum) and the growth rate in the ASU/APESMA/NUW EBA is 4.5 per cent per annum.

The stickiness experienced in the wage growth rates in EBAs reflects a range of factors (as outlined above), all of which would continue irrespective of the AER's approach to escalating expenditure forecasts for labour price growth, and thus the AER's decision cannot be expected to either increase or decrease the wage growth rates included in future EBAs.

In its report accompanying our regulatory proposal, Frontier Economics outlined the reasons why its forecasts based on historical average EBA outcomes would ensure distributors still have incentives to reduce costs over time. Frontier Economics stated that a scheme based on the average EBA outcomes for the comparator group would have the desirable property of driving efficiencies over time, rather than weakening incentives for efficiency because:[180]

- no single network service provider can influence materially the growth rates determined by the AER under a comparator EBA approach because each network service provider's EBA is only one among several that are used to set rates;
- once growth rates are set, every network service provider has a strong profit incentive to negotiate hard to secure lower EBA outcomes than the allowances set by the AER. These incentives are present because allowing regulated businesses to keep the cost of outperformance for a period of time as a means of encouraging efficiency improvements is a cornerstone of incentive regulation and the AER's EBSS provides a continuous incentive for network service providers to pursue efficiency improvements in operating expenditure;
- every network service provider within the comparator group would have similar incentives to beat allowances (and thus the average EBA for the comparator group); and
- if the labour cost escalation allowances are set by reference to average EBA rates, even if only a proportion of the comparator group succeed in achieving savings, the average for the comparator group at the next regulatory reset (all else remaining equal) would be lower and average EBA outcomes would be expected to fall over time.

In considering our proposed approach in its report on labour price growth, NERA (UK) also expressly dismissed any concerns as to incentives being undermined, indicating that any incentive a distributor may have to raise wages through EBAs is mitigated by basing allowances on an average group of EBAs in the relevant industry (as

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178 CitiPower, *Regulatory Proposal 2016–2020*, p. 75. See also CP PUBLIC ATT 7.8 - CEPU, *Log of claims*, 18 June 2013, item 21.

179 ASU, *Log of claims*, June 2013; APESMA, *Log of claims*, June 2013, item 1; NUW, *Log of claims*, item 3.

180 CP PUBLIC ATT 7.3 - Frontier Economics, *Labour cost escalation forecasts using enterprise bargaining agreements*, February 2015, pp. 23-24.

occurs with the use of Frontier Economics' forecasts) and by the incentive provided to distributors to reduce operating expenditure during a regulatory control period.[181]

Notwithstanding, should the AER still have concerns that a distributor's actual EBA outcomes are inefficient, the AER should assess the efficiency and prudency of the EBA negotiation process and outcomes. For the reasons discussed above and in detail in our initial regulatory proposal, our EBA outcomes reflect efficient and prudent labour price growth.

Our forecasts better meet the AER's expenditure forecasting principles than the AER's EGWW WPI forecasts

While the AER conceded that our proposed labour price growth forecasting methodology is simpler and more transparent than the forecasting methodologies adopted by DAE and BIS Shrapnel, the AER stated that, on balance, use of the forecast changes in the EGWW WPI to determine labour price growth better meets the principles set out in the AER's *Expenditure forecast assessment guideline*.[182]

In drawing its conclusion, the AER stated that it considers that forecasting methods based on historic averages do not account for changes in labour market conditions that will prevail in the forecast period. The reasons why the AER errs in reaching this conclusion are discussed above. Further, also outlined above are the reasons why EBA based outcomes are more representative of labour price growth rates than forecasts of change in the EGWW WPI. These matters directly support a conclusion that EBA-based forecasts are more valid, accurate and reliable, robust and fit for purpose than the AER's forecasts based on EGWW WPI forecasts.

In applying forecasts of the EGWW WPI to determine labour price growth, the AER fails to recognise significant limitations of the EGWW WPI forecasts used by the AER. In addition to the forecasts being less reflective of our labour price growth than EBA-based forecasts, consultant forecasts of the EGWW WPI vary widely, highlighting the volatility of measurement techniques.[183]

In outlining the reasons why the EGWW WPI forecasts fail to meet the AER's principles for assessing expenditure forecasts, Frontier Economics notes that the lack of transparency regarding the forecasting techniques used by consultants who derive WPI forecasts means that it is impossible for the AER and other stakeholders to assess the validity of forecasting techniques or to test the sensitivity or robustness of the forecasts.[184] Frontier Economics explains that, given the large gap between the forecasts derived by DAE and BIS Shrapnel, the methodologies used by different forecasters clearly matters.[185] Further, Frontier Economics concludes that, while it is generally sympathetic to the approach of combining forecasts from different sources, such a policy is not a substitute for transparency.[186]

The DAE report explains that its WPI forecasts are drawn from its proprietary labour cost model, linked to its macroeconomic model. Models of this kind inevitably entail numerous assumptions and methodological choices which have not been disclosed to us or made available to our expert advisers for review. This lack of transparency in and of itself means that no proper assessment of whether or not the resulting forecasts meet the principles set out in the AER's *Expenditure forecast assessment guideline* can be undertaken. It is also contrary to

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181 NERA (UK), *Expert report on the allowed rate of change in SA Power Networks' expenditure due to expected inflation in labour costs*, 23 June 2015, p. 11.

182 AER, *Preliminary decision CitiPower distribution determination 2016–20*, October 2015, p. 7-58.

183 Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 21.

184 Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 20-21.

185 Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 12.

186 Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 13.

the AER's own asserted preference for transparency as described in its *Expenditure forecast assessment guideline*:[187]

> *A technique that we or stakeholders are unable to test (sometimes referred to as a 'black box') is not transparent because it is not possible to assess the results in the context of the underlying assumptions, parameters and conditions. In our view, the more transparent a technique, the less susceptible it is to manipulation or gaming. Accordingly, we take an unfavourable view of forecasting approaches that are not transparent.*

By contrast, wage growth rates in EBAs are transparent and forecasts based on these can be calculated from publicly available data and are replicable. Further, wage growth rates in EBAs have been relatively stable over time and this stability is evident irrespective of the period over which the average is taken.

Our proposed forecasts thus better meet all of the principles set out in the *Expenditure forecast assessment guideline* and no 'balancing' of the kind referred to by the AER is required to select between forecasting methodologies.

<u>The AER errs in averaging only DAE's and BIS Shrapnel's forecasts of the EGWW WPI</u>

Even if it were accepted (contrary to our contentions) that the AER was correct in using forecasts of the EGWW WPI to forecast any element of labour price growth, we have two concerns with the AER's methodology.

First, in forecasting the EGWW WPI in our preliminary determination, the AER errs in applying an average of DAE's and BIS Shrapnel's forecasts, without also including in its average the forecasts of EGWW WPI prepared by CIE.

The AER stated that, given WPI growth rates (both at the Australian all industries and EGWW industry level) are currently the lowest on record, it considers it more likely that the average WPI growth rate over the forecast period will be lower than the historic average. Given DAE's forecasts for the Victorian EGWW WPI are lower than BIS Shrapnel's, the AER concludes it likely that DAE's forecast will be the most accurate because they better reflect current labour market conditions.[188]

The AER's conclusions have no proper basis. The fact that WPI growth rates are the lowest on record says nothing about whether the (lower) DAE forecasts are a more realistic forecast of WPI growth rates for the 2016–2020 regulatory control period than the WPI forecasts from BIS Shrapnel or CIE. There are a wide range of factors that will influence wage growth rates.

The AER's comments are also contrary to:

- its finding that DAE has historically under-forecast EGWW WPI at the national level; and
- its ultimate decision to adopt an average of DAE's and BIS Shrapnel's forecasts on the basis that its analysis in its 2012 transmission determination regarding Powerlink found that an average of the forecast from DAE and BIS Shrapnel was closest to actual WPI growth.[189]

Further, Frontier found that DAE under forecast the EGWW WPI for South Australia by quite a significant margin, about 1 percentage point, in 2012–2013 and 2013–2014. Despite this DAE made further significant downward revisions to its forecast for South Australia and Victoria.[190]

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[187] CP PUBLIC ATT 9.4 - AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 16.

[188] AER, *Preliminary decision CitiPower distribution determination 2016–20*, October 2015, p. 7-57.

[189] AER, *Preliminary decision CitiPower distribution determination 2016–20*, October 2015, p. 7-57.

[190] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 17-18.

If it was the case that the EGWW WPI was reflective of labour price growth rates (which we say it is not), we would not have any in principle objection to the AER's decision to use an average of EGWW WPI forecasts. However, while the AER has enthusiastically endorsed an approach which averages forecasts, the AER has failed to include in its forecast of EGWW WPI, the EGWW WPI forecasts prepared by CIE, submitted with our regulatory proposal.

The AER does not address in the preliminary determination why it does not take into account CIE's forecasts of the EGWW WPI in forecasting labour price growth. In its preliminary determination regarding AusNet Services the AER states:[191]

> *We have used BIS Shrapnel, rather than CIE because analysis has shown that BIS Shrapnel over forecast and CIE's forecast[s] are higher than BIS Shrapnel's. Further, the profile of CIE's forecast looks inconsistent with current labour market conditions. For both DAE and BIS Shrapnel forecast WPI growth rates start low and peak in 2019. This profile appears consistent with current WPI growth rates being the lowest on record. CIE's forecasts, however, peak in 2016 and then remain consistently above the historic average for the remainder of the forecast period.*

CIE has downgraded its forecasts for growth in gross domestic product (**GDP**) in the short term. This is because CIE is using forecasts for Australian GDP growth published by the International Monetary Fund (rather than forecasting the level of activity in each state then summing to get a forecast for Australia), which CIE considers produces more accurate forecasts.[192] CIE has also upgraded forecast labour supply growth. [193] The issues raised by the AER therefore no longer arise.

As noted by Frontier Economics, the statistics literature recognises that, in order for the combining of forecasts to improve accuracy, each source must contribute some useful information and the different sources should have as little positive correlation as possible.[194]

CIE has conducted a comparison of the forecasts of GDP, employment, implied productivity and inflation of a range of experts, including CIE, DAE and BIS Shrapnel.[195] These economic indicators are inputs to the forecasting of the EGWW WPI. CIE's comparison shows that there are differences between the forecasters on a range of matters, which suggests each are using different sources of information and thus combining forecasts of all three may improve the accuracy of the forecasts of the EGWW WPI. In any event, given there is limited transparency as to each of the data inputs to, and methodologies for estimating, the EGWW WPI forecasts, there is no basis for excluding the forecasts from CIE.

Secondly, the AER has not placed any weight on the EBA-based forecasts. In doing so, the AER disregarded the fact that EBAs provide the most direct indication of labour costs faced by distributors. Frontier Economics recommends that, in the event the AER does not apply EBA-based forecasts as the sole measure of labour price growth, it should still recognise that those forecasts contribute very valuable information on labour price growth rates experienced by distributors (which EGWW WPI based forecasts reflect poorly) and that rather than rejecting the EBA-based forecasts altogether, a more reasonable approach would be for the AER to assign at least as much weight to EBA-based forecasts as it does to EGWW WPI forecasts.[196]

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[191] AER, *Preliminary decision, AusNet Services distribution determination 2016–20*, October 2015, p. 7-56.

[192] CIE, *Labour price forecasts*, 20 November 2015, p. 25.

[193] CIE, *Labour price forecasts*, 20 November 2015, p. 25.

[194] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 39.

[195] CIE, *Labour price forecasts*, 20 November 2015, pp. 27-32.

[196] Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, pp. 39-40. A review of the empirical evidence from the forecasting literature suggests applying equal weights to forecasts unless there is strong evidence to support unequal

Our revised regulatory proposal

We maintain our proposed EBA-based labour price growth forecasts, with the exception that we have incorporated updated forecasts by Frontier Economics which reflect one additional EBA approved subsequent to the submission of our regulatory proposal. That is, we propose labour price growth forecasts:

- for the period up until after the final payment contemplated under our two current EBAs, based on the actual annualised wage growth rates in our EBAs, weighted by reference to the proportion of employees on each EBA; and
- for the period after the final payment contemplated under the current EBAs until 2020, the five year historical average EBA wage growth rate for all privately owned electricity networks as calculated by Frontier Economics.[197]

Our labour price growth forecasts are presented in the table below.

Table 4.5 Labour price growth rate forecasts (per cent)

Labour price growth rate	2016	2017	2018	2019	2020
Nominal	4.52	4.31	4.31	4.31	4.31
Real	1.97	1.76	1.76	1.76	1.76

Source: CitiPower

4.2.3 Non-labour price growth rates for operating expenditure

While we initially proposed a material price growth rate of zero, since we submitted our regulatory proposal, the Australian dollar (**AUD**) has fallen considerably against the United States (**USD**), with the result that we now expect real price growth in materials over the 2016–2020 regulatory control period. We have reflected this by proposing a real price growth for our 'non-labour' component that is a weighted average of the real price growth rate for materials forecast by Jacobs (for 'materials' expenditure) and a zero price growth rate for all other expenditure in our 'non-labour' component.

Initial regulatory proposal

As outlined above, in our regulatory proposal, we proposed price growth rates for labour, contracts and materials expenditure. For operating expenditure, the AER determined a 'non-labour' component of real price growth intended to encompass our materials expenditure and contracts expenditure other than expenditure on labour employed by contractors that provide 'field services'.

As noted above, we proposed contracts growth rates based on construction sector WPI forecasts for Victoria prepared by CIE.[198]

In our regulatory proposal, we proposed a materials price growth rate of zero.[199] This is because we expected our materials input costs, considered in aggregate, to grow in the 2016–2020 regulatory control period at approximately the same rate as CPI.

weightings of forecasts: Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 40 (footnote 72).

197 Frontier Economics, *Review of AER's preliminary decision on labour price growth*, December 2015, p. 4.

198 CitiPower, *Regulatory Proposal 2016–2020*, p. 79.

199 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, p. 80.

AER's preliminary determination

In its preliminary determination, the AER adopted zero real price growth for all operating expenditure included in its 'non-labour' component.[200]

In rejecting our proposed contracts price growth rate, the AER stated that we did not provide reasons in our regulatory proposal as to why we used forecasts for the construction sector WPI for Victoria for expenditure on non-field services and, in particular, that we did not state why the construction sector most closely reflects the services we contract.[201]

The AER considered the historical annual growth in PPIs from the ABS in selected classifications ('All industries, domestic, intermediate inputs', 'Data processing, web hosting and electronic information storage services', 'Other administrative services', 'Legal and accounting services' and 'Market research and statistical services'). These industries are those the AER considered '*most closely reflect the non-field services that an efficient service provider would purchase*' and are the same PPIs that the AER uses for its non-labour inputs in the operating expenditure cost function modelling used to measure historic productivity.[202]

The AER noted that while the PPIs of some non-field services have (historically) increased by more than CPI, others have increased by less and the growth of expenditure on non-field services tends to grow at a similar rate to CPI.[203] The AER concluded therefore that there is no evidence that the price of non-field services purchased from contractors by an efficient service provider varies materially from CPI.

Without setting out its reasons, the AER in effect accepted our proposed materials price growth rate of zero for operating expenditure.

Our response to the AER's preliminary determination

While we are comfortable that the majority of non-labour expenditure, on balance, can be expected to increase in line with CPI during the 2016–2020 regulatory control period, there are two significant exceptions.

First, we now expect there to be real price growth of materials costs in the period. Since our initial regulatory proposal was submitted in April 2015, the AUD has fallen considerably against the USD.[204]

This decline is not expected to be reversed over the 2016–2020 regulatory control period.

We engaged an independent expert, Jacobs, to forecast real and nominal material cost driver price escalation indices for each year of the 2016–2020 regulatory control period.[205] As part of this exercise, using the AER's preferred methodology for forecasting changes in the AUD/USD exchange rate, Jacobs forecast the AUD/USD exchange rate for each year of the 2016–2020 regulatory control period as set out in the following table.

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200 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-55, 7-60.

201 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-63.

202 AER, *Preliminary decision CitiPower distribution determination 2016–20*, October 2015, p. 7-63.

203 AER, *Preliminary decision CitiPower distribution determination 2016–20*, October 2015, p. 7-64.

204 Reserve Bank of Australia, Exchange Rates - Daily - 2014 to current, accessed 18 December 2015: http://www.rba.gov.au/statistics/historical-data.html#exchange-rates.

205 Jacobs, *Escalation indices forecast 2016–2020, CitiPower, Material asset price escalation indices forecast*, 17 November 2015.

Table 4.6 Forecast AUD/USD exchange rate

	2016	2017	2018	2019	2020
AUD 1.00 = USD	0.708	0.700	0.694	0.687	0.695

Source: Jacobs, *Escalation indices forecast 2016–2020, CitiPower, Material asset price escalation indices forecast*, 17 November 2015, p. 16.

By contrast, the average AUD/USD exchange rate over 2014 was 0.903.[206] There is, therefore, now a significant divergence between the exchange rate underpinning our expenditure forecasts for the 2016–2020 regulatory control period and the forecast exchange rates over that period.

The commodities used to produce the finished goods we acquire for the purposes of operating, maintaining and undertaking capital works on our network (namely, copper, aluminium, steel and oil) are traded in an international market. As these commodities prices are quoted in USD in the international market,[207] the AUD/USD exchange rate directly impacts on our materials cost in AUD terms.

The forecasts prepared by Jacobs indicate that our materials costs will increase at a greater rate than CPI over the 2016–2020 regulatory control period (in part informed by the downturn in the AUD/USD exchange rate expected to continue over the period). Accordingly, we are now proposing to apply real materials price growth rates to our expenditure forecasts for the 2016–2020 regulatory control period on the basis of the forecasts prepared by Jacobs.

Secondly, we consider that there is likely to be real price growth in contracts expenditure on non-field services in 2016–2020. These contracts are primarily for labour based services and thus wage price growth is the key driver of real price growth in expenditure on these services.

The AER's analysis by reference to a range of PPIs is unsound because:

- the AER has not undertaken a detailed analysis to determine that the PPIs used, or the weightings used to determine an overall weighting, are appropriate. This is contrary to Economic Insights' statement in its June 2013 report for the AER that '[i]t would be appropriate to confirm that the PPIs and price index … reflect current NSP opex activities and opex composition'.[208] As Economic Insights went on to state in its report, the accuracy of its proposed approach (for the purposes of benchmarking distributors) 'will depend on changes in ABS sectoral and economic-wide price indexes accurately reflecting changes in opex prices faced by all NSPs.'[209]
- the AER has not considered forecasts of the PPIs, but rather limited its assessment to analysis of historical PPIs. Such an approach is inconsistent with the AER's approach to other elements of its determination of real price growth and is inconsistent with the Rules and Law which require a forward looking assessment of expected costs in the forthcoming regulatory control period.

We consider that the EGWW WPI is an appropriate means of measuring real price growth in contracts expenditure on 'non-field' services. We engaged CIE to prepare updated EGWW WPI forecasts, which take into account actual data up to September 2015 and updated macroeconomic forecasts now available. CIE's report, *Labour price forecasts*, is attached.[210] Even if the AER concludes that the EGWW WPI does not capture the

206 Calculated using: Reserve Bank of Australia, Exchange Rates - Daily - 2014 to current, accessed 18 December 2015: http://www.rba.gov.au/statistics/historical-data.html#exchange-rates.

207 Jacobs, *Escalation indices forecast 2016–2020, CitiPower, Material asset price escalation indices forecast*, 17 November 2015, p. 7.

208 Economic Insights, *Economic Benchmarking of Electricity Network Service Providers*, 25 June 2013, p. 68.

209 Economic Insights, *Economic Benchmarking of Electricity Network Service Providers*, 25 June 2013, p. 68.

210 CIE, *Labour price forecasts*, 20 November 2015.

expected growth in this expenditure, real growth is also expected in the all industries WPI. There is no basis for a suggestion that wages for 'non-field' services are likely to increase at a lower rate than the general industry. Given the labour intensive nature of these services, it follows that real price growth in overall expenditure is expected.

However, to ensure that our estimate of real price growth (described above) remains conservative, we have proposed zero real price growth to this expenditure for the purposes of our revised regulatory proposal.

Accordingly, we propose real price growth rates for non-labour expenditure on the basis of a weighted average of our materials price growth forecasts (determined by Jacobs) and a zero price growth rate for all other 'non-labour' expenditure.

Our revised regulatory proposal

We propose real price growth rates for non-labour expenditure on the basis of a weighted average of our materials price growth forecasts (determined by Jacobs) and a zero price growth rate for all other expenditure in this component.

The materials price growth rate forecasts prepared by Jacobs are summarised in the following table.

Table 4.7 Materials price growth rate forecasts (per cent)

Materials price growth rate	2016	2017	2018	2019	2020
Nominal	4.12	3.80	3.18	3.48	3.55
Real	1.58	1.27	0.66	0.96	1.02

Source: CitiPower and Jacobs, *Escalation indices forecast 2016–2020, CitiPower, Material asset price escalation indices forecast*, 17 November 2015, p. 16.

The resulting real price growth rates for non-labour operating expenditure are set out in the following table.

Table 4.8 Non-labour price growth rate forecasts (per cent)

Non-labour price growth rate	2016	2017	2018	2019	2020
Nominal	2.62	2.59	2.55	2.57	2.57
Real	0.11	0.09	0.05	0.07	0.07

Source: CitiPower

4.2.4 Overall real price growth of operating expenditure

Initial regulatory proposal

The overall value of real price growth for operating expenditure for each year of the 2016–2020 regulatory control period included in our regulatory proposal is set out in the table below. The overall value reflects the components of real price growth, input price weightings and forecasts of real price growth described above.

Table 4.9 Operating expenditure to account for real price growth in our regulatory proposal ($ million, 2015)

Operating expenditure	2016	2017	2018	2019	2020
Labour	1.7	2.4	3.3	4.1	4.8
Materials	-	-	-	-	-
Contracts	1.0	1.9	2.9	3.8	4.5
Total value of real price growth	**2.6**	**4.3**	**6.1**	**7.8**	**9.4**

Source: CitiPower, *Regulatory Proposal 2016–2020*, April 2015, p. 80.

AER's preliminary determination

The AER rejected our forecast operating expenditure to account for real price growth and instead substituted its own forecasts determined by reference to its own components of real price growth, input price weights and real price growth rates described above. The overall value of real price growth for operating expenditure for each year of the 2016–2020 regulatory control period included in the AER's preliminary determination is $6.4 million (real 2015) across the period.[211]

Our response to the AER's preliminary determination

Real price growth is a key component of our total forecast operating expenditure. It comprised 6.02 per cent of the forecast operating expenditure in our regulatory proposal.

Whereas we proposed operating expenditure pursuant to real price growth of $30.2 million (real 2015) over the 2016–2020 regulatory control period, the AER's preliminary determination reduced this to $6.4 million (real 2015).[212]

The AER's failure to properly account for real price growth in the preliminary determination results in expenditure allowances that do not reasonably reflect the operating expenditure criteria. In particular, its resultant expenditure allowances fail to reflect a realistic expectation of the cost inputs required to achieve the operating expenditure objectives and do not provide us with a reasonable opportunity to recover the efficient costs incurred in complying with applicable regulatory obligations or requirements.

Our revised regulatory proposal

We have forecast operating expenditure to account for real price growth by applying our forecast real price growth rates for labour and non-labour expenditure described above to the proportion of expenditure within each component of expenditure determined as an average over the period 2012 to 2014. The resulting overall value of real price growth for each year of the 2016–2020 regulatory control period is set out in the following table.

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[211] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-21.

[212] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-21. We note that a small proportion of the difference between our proposed operating expenditure to allow for real price growth and the AER's allowance arises from the (slight) reduction in the direct operating expenditure allowance for the 2016–2020 regulatory control period in the AER's preliminary determination (as compared to the direct operating expenditure proposed in our regulatory proposal).

Table 4.10 Operating expenditure to account for real price growth ($ million, 2015)

Operating expenditure	2016	2017	2018	2019	2020
Labour	1.1	2.1	3.1	4.2	5.3
Non-labour	0.0	0.1	0.1	0.1	0.1
Total value of real price growth	**1.1**	**2.2**	**3.2**	**4.3**	**5.4**

Source: CitiPower

4.3 Real price growth of capital expenditure

We have largely maintained our approach to forecasting real price growth for capital expenditure, which was, in the main, accepted by the AER in its preliminary determination. We have, however, updated our materials price growth forecasts to reflect the real price growth in materials now expected. We also maintain that our forecasts of labour price growth on the basis of EBA-based forecasts result in capital expenditure forecasts required to achieve the capital expenditure objectives and reasonably reflect the capital expenditure criteria.

4.3.1 Initial regulatory proposal

In our regulatory proposal we proposed to escalate capital expenditure on the basis of three categories of expenditure: labour, materials and contracts.[213]

We proposed labour price growth rates consistent with the labour price growth rates described above in respect of operating expenditure.

Also as in the case of operating expenditure, we proposed a materials price growth rate of zero because we expected our materials input costs, considered in aggregate, to grow in the 2016–2020 regulatory control period at approximately the same rate as CPI.

We proposed contracts price growth rates based on forecasts of the construction sector WPI for Victoria prepared by the CIE.[214] The rates included in our regulatory proposal were as follows.

Table 4.11 Regulatory proposal contracts price growth rate forecasts (per cent)

Contracts price growth rates	2016	2017	2018	2019	2020	Average 2016–2020
Nominal	3.59	4.81	4.38	4.36	4.39	4.31
Real	0.96	2.15	1.73	1.72	1.74	1.66

Source: CitiPower, *Regulatory Proposal 2016–2020*, April 2015, p. 79; CP PUBLIC ATT 7.4 - CIE, *Labour price forecasts*, 17 December 2014, p. 7.

We applied our proposed real price growth rates to the proportion of our capital expenditure attributable to each of labour, materials and contracts, as determined by reference to our actual expenditure for standard control services over the period 2011 to 2014. These weights are set out in the table below.

[213] CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 80.

[214] CitiPower, *Regulatory Proposal 2016–2020*, April 2015, p. 79.

Table 4.12 Proportion of capital expenditure attributable to labour, materials and contracts (per cent)

Expenditure type	Labour	Materials	Contracts
Capital expenditure	32.3	21.7	45.9

Source: CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 79.

The resulting capital expenditure to account for real price growth included in our regulatory proposal is set out in the following table.

Table 4.13 Capital expenditure to account for real price growth in our regulatory proposal ($ million, 2015)

Capital expenditure	2016	2017	2018	2019	2020
Labour	0.9	1.8	2.6	3.2	3.3
Materials	-	-	-	-	-
Contracts	0.9	3.4	4.5	5.0	5.1
Total value of real price growth	**1.7**	**5.2**	**7.2**	**8.2**	**8.4**

Source: CitiPower, *Regulatory Proposal 2016–2020*, April 2015, p. 80.

4.3.2 AER's preliminary determination

The AER accepted our proposal to apply real price growth rates to labour, materials and contracts, and our proposed input price weights for each. The overall value of real price growth for capital expenditure for the 2016–2020 regulatory control period, however, was lower in the AER's preliminary determination than in our regulatory proposal as a result of the adoption by the AER of lower price growth rates than those we proposed, as well as lower capital expenditure allowances than we proposed over the 2016–2020 regulatory control period.

The AER applied the EGWW WPI for the purposes of labour price growth (rather than our EBA-based forecasts, as described above in respect of operating expenditure) and zero materials price growth rates. The AER accepted the use of construction sector WPI for contracts price growth rates but replaced CIE's forecasts (as proposed) with an average of forecasts prepared by DAE (for the AER) and BIS Shrapnel (for JEN and UED).

In making its preliminary determination, on the basis of its real price growth forecasts, the AER reduced our proposed capital expenditure to account for real price growth by $11.19 million (2015 real).[215] The overall allowance for real price growth in the AER's preliminary determination was further reduced given the AER's decision to substitute lower direct capital expenditure forecasts over the period.

4.3.3 Our response to the AER’s preliminary determination

Real price growth is a key component of our capital expenditure. The AER's failure to properly account for real price growth in the preliminary determination results in capital expenditure allowances that do not reasonably reflect the capital expenditure criteria. In particular, its resultant expenditure allowances fail to reflect a realistic expectation of the cost inputs required to achieve the capital expenditure objectives and do not provide us with a reasonable opportunity to recover the efficient costs incurred in complying with applicable regulatory obligations or requirements.

[215] AER, *Preliminary decision CitiPower - capex real cost escalation model*, October 2015, cell G14.

We maintain the approach of applying real price growth rates to the labour, materials and contracts components of capital expenditure and the input price weightings for each set out in our regulatory proposal and accepted by the AER in its preliminary determination.

For the reasons outlined above in respect of operating expenditure:[216]

- we also maintain that the labour price growth rates for capital expenditure should be EBA-based forecasts, rather than forecasts of the EGWW WPI (as applied by the AER); and
- even if the AER was correct in using forecasts of the EGWW WPI to forecast labour price growth, the AER erred in:
  - failing to reflect in any way the EBA-based forecasts we proposed, in particular, by not also including the EBA-based forecasts in its average of forecasts; and
  - adopting an average of DAE's and BIS Shrapnel's forecasts, and not including in its average the forecasts of the EGWW WPI prepared by CIE.

For the reasons outlined above in respect of materials price growth rates for operating expenditure, we also now propose real price growth rates for materials costs for capital expenditure based on the forecasts of real price growth in materials prepared by Jacobs.

For the escalation of contracts capital expenditure, the AER provided no reasoning in support of its decision to replace our proposed forecasts of construction sector WPI prepared by CIE with the average of forecasts of construction sector WPI prepared by DAE and BIS Shrapnel. While difficult to second-guess the AER's reasoning process, it may be that the AER did so on the basis that it concluded in respect of the use of the EGWW WPI for labour price growth for operating expenditure that averaging the forecasts produced by DAE and BIS Shrapnel produces the best forecast. However, if this was the basis for the AER's decision, it is erroneous. First, there is no evidence to suggest that the AER's analysis of forecasting accuracy in respect of the EGWW WPI translates to forecasting accuracy in respect of the construction sector WPI. Secondly, for the reasons outlined above in respect of labour price growth of operating expenditure, the AER was in error to conclude that averaging the EGWW WPI forecasts produced by DAE and BIS Shrapnel produces more realistic forecasts of EGWW WPI than averaging the forecasts produced by DAE, BIS Shrapnel and CIE. The analysis therefore provides no basis for using an average of the forecasts prepared by DAE and BIS Shrapnel for construction sector WPI, rather than an average of the construction sector WPI forecasts prepared by DAE, BIS Shrapnel and CIE.

We engaged CIE to prepare updated construction sector WPI forecasts, which take into account the actual data up to September 2015 and updated macroeconomic forecasts now available. CIE's report, *Labour price forecasts*, is attached.[217]

We propose that real price growth for contracts capital expenditure be forecast using an average of the forecasts of DAE, BIS Shrapnel and CIE of construction sector WPI.

4.3.4 Our revised regulatory proposal

We maintain our approach to defining the three components of capital expenditure (labour, materials and contracts) and the input price weightings for each set out in our regulatory proposal and accepted by the AER in its preliminary determination.

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216 We note the AER's *Capital expenditure sharing scheme* also ensures the efficiency of capital expenditure.

217 CIE, *Labour price forecasts*, 20 November 2015.

For the calculation of labour price growth rates, we propose to apply the EBA-based forecasts described above in respect of operating expenditure.

We propose real price growth rates for materials costs for capital expenditure based on the forecasts of real price growth in materials prepared by Jacobs and set out above in respect of operating expenditure.

Our revised proposed contracts price growth rates for capital expenditure are an average of updated construction sector WPI forecasts for Victoria prepared by CIE and the construction sector WPI forecasts prepared by DAE and BIS Shrapnel used by the AER in its preliminary determination. These contracts price growth rates are provided in the table below.

Table 4.14 Contracts price growth rate forecasts (per cent)

Contracts growth rates	2016	2017	2018	2019	2020
Nominal	3.40	3.80	3.77	3.68	3.63
Real	0.88	1.27	1.24	1.13	1.10

Source: CitiPower and CIE, *Labour price forecasts*, November 2015 p. 7

The resulting capital expenditure we now propose to account for real price growth in the 2016–2020 regulatory control period is set out in the following table.

Table 4.15 Capital expenditure to account for real price growth ($ million, 2015)

Capital expenditure	2016	2017	2018	2019	2020
Labour	0.6	1.5	2.0	2.3	2.3
Materials	0.6	1.5	1.8	2.0	2.0
Contracts	1.2	2.9	3.7	4.1	4.0
Total value of real price growth	**2.4**	**5.9**	**7.6**	**8.4**	**8.3**

Source: CitiPower

Demand and customer forecasts 5

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5 Demand and customer forecasts

Our demand forecasts reflect a realistic expectation of demand for standard control services on our network over the 2016–2020 regulatory control period.

We have updated our forecasts following the 2014/2015 summer. We have retained our methodology of undertaking comprehensive forecasts at both the connection point level and zone substation level, and applying a best practice reconciliation approach to ensure the relevant information from both sources is effectively utilised.

Importantly, our forecasting methodology ensures our demand forecasts reflect realistic demand requirements at the spatial level. This is essential for identification of future local network constraints and capital augmentation requirements. As acknowledged by the AER:[218]

> *Localised demand growth (spatial demand) drives the requirement for specific growth projects or programmes. Spatial demand is not uniform across the entire network[.]*

Our demand forecasts therefore ensure that our capital and operating expenditure forecasts reflect those of an efficient and prudent distribution service provider operating in our network area.

We dispute the Australian Energy Regulator's (**AER**) conclusion that our forecasts do not account for the impact on demand of recent and future changes in electricity markets. Our forecasting approach captures the impact on forecast demand of electricity market changes that:

- occurred during the most recent ten years, through the modelling process which relies on ten years of historical data; and
- are expected to have a greater impact on demand in the future than historically, through post-modelling adjustments.

The AER has provided no evidence to substantiate its view or quantify the impact on forecast demand of recent or future changes in electricity market conditions that it considers are not captured through our modelling approach.

We also dispute the AER's preliminary determination to substitute our forecasts for the Australian Energy Market Operator's (**AEMO**) connection point forecasts. AEMO's forecasts do not reflect a realistic expectation of demand because, amongst other things,:

- AEMO's forecasts do not incorporate key drivers of demand, such as income, population and prices, at the connection point level;
- AEMO's baseline connection point forecasts are based solely on historical time trends; and
- AEMO's reconciliation process results in a simple proportional allocation of state-wide forecast demand growth across all connection points in Victoria.

Consequently, AEMO's demand forecasts do not account for different demand characteristics of different connection points and therefore do not reflect realistic demand forecasts at the spatial level. Accordingly, AEMO's forecasts do not provide a reasonable basis for forecasting our capital and operating expenditure requirements.

AEMO has only been preparing its connection point forecasts since 2014. Its forecasting process is in its infancy and continues to evolve over time. Conversely, we have been preparing demand forecasts for our network for 21 years. We have a wealth of local knowledge and experience regarding our network

[218] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 108.

characteristics and demand requirements.

Further, the AER applied AEMO's forecasts without assessing them against its own best practice forecasting principles or the requirements of the National Electricity Rules (**Rules**) and the National Electricity Law (**Law**).

Cambridge Economic Policy Associates (**CEPA**) reviewed our forecasts and AEMO's forecasts against the AER's best practice demand forecasting principles and the requirements in the Rules and Law. CEPA found AEMO's forecasting approach to be less satisfactory than our approach in meeting the AER's best practice forecasting principles. CEPA concluded that:[219]

> *After reviewing both AEMO's and the Businesses' approaches we consider that the Businesses' approach to demand forecasting at the connection point level is more likely to achieve the NER and hence the NEO than AEMO's.*

Our forecasts provide a realistic expectation of demand at the connection point level and provide a reasonable basis for assessing the location of future network constraints and our efficient capital and operating expenditure requirements. If the AER adopts AEMO's forecasts rather than our forecasts, it will result in expenditure forecasts that underestimate the expenditure required to meet the operating expenditure and capital expenditure objectives in the Rules, and in particular to meet or manage the expected demand for standard control services.

5.1 Rule requirements

The constituent decisions on which a distribution determination is predicated include (amongst others):

- a decision in which the AER either accepts or does not accept the total forecast capital expenditure for the regulatory control period proposed in the building block proposal and, if the AER does not accept that forecast, sets out an estimate of the total required capital expenditure for the period (clause 6.12.1(3));
- a decision in which the AER either accepts or does not accept the total forecast operating expenditure for the regulatory control period proposed in the building block proposal and, if the AER does not accept that forecast, sets out an estimate of the total required operating expenditure for the period (clause 6.12.1(4)); and
- a decision in which the AER decides other appropriate amounts, values or inputs (clause 6.12.1(10)).

Clauses 6.5.6 and 6.5.7 of the Rules provide, among other things, that:

- the building block proposal must include the total forecast operating and capital expenditure for the regulatory control period that the distributor considers is required in order to achieve each of the operating and capital expenditure objectives set out in clauses 6.5.6(a) and 6.5.7(a) respectively; and
- the AER must accept the forecast of required operating expenditure or capital expenditure (as the case may be) that is included in the building block proposal if it is satisfied that the total forecast operating or capital expenditure reasonably reflects the operating or capital expenditure criteria set out in clause 6.5.6(c) or 6.5.7(c) respectively.

Similarly, if the AER does not accept the total forecast capital expenditure or operating expenditure (as the case may be), the estimate of the total required expenditure for the regulatory control period must be that which the AER is satisfied reasonably reflects the capital or operating expenditure criteria, taking into account the capital or operating expenditure factors (clause 6.12.1(3)(ii) and (4)(ii)).

[219] CEPA, *Review of demand forecasting approaches*, December 2015, pp. iv and 36.

Each of the operating and capital expenditure criteria are specified by reference to the achievement of the operating and capital expenditure objectives. Those objectives include (amongst others) meeting or managing the expected demand for standard control services over the period (clauses 6.5.6(a)(1) and 6.5.7(a)(1)). Further, one of the three operating and capital expenditure criteria is a realistic expectation of the demand forecast and cost inputs required to achieve those objectives (clauses 6.5.6(c)(3) and 6.5.7(c)(3)).

The explanatory statement to the AER's Expenditure Forecast Assessment Guideline sets out the principles of best practice demand forecasting that the AER will take into account in assessing demand forecasts.[220] These are: accuracy and unbiasedness, transparency and repeatability, incorporation of key drivers, weather normalisation, model validation and testing, use of the most recent input information, spatial (bottom-up forecasts) validated by independent system level (top-down) forecasts, adjusting for temporary transfers, adjustment for discrete block loads, incorporation of maturity profile of service area in spatial time series, use of load research and regular review of demand forecasting approaches. Clause 6.2.8 of the Rules requires that if the AER makes a determination that departs from the Guideline, it must state its reasons for doing so.

5.2 Demand forecasts

5.2.1 Initial regulatory proposal

As recognised by the Rules, our demand forecasts are used to develop our 2016–2020 operating and capital expenditure forecasts. In particular, we use our demand forecasts, both top-down connection point and bottom-up spatial forecasts, to calculate the forecast load at each zone substation, on each sub-transmission line and on each feeder. This is then used to identify whether additional capacity is required at any location, and to assess the augmentation options available to address the identified network constraints. This process informs our capital expenditure requirements. We also use our demand forecasts to forecast our operating expenditure requirements.

For our regulatory proposal our demand forecasts were developed using a robust process that combines our own detailed knowledge of the network with independent economic analysis. Detailed information on our forecasting approach is set out in Appendix C of our initial regulatory proposal.[221]

In summary, we engaged the Centre for International Economics (**CIE**), an independent expert forecaster, to prepare forecasts of maximum demand at each connection point and also at the network level, using econometric modelling. We separately developed our own bottom-up maximum demand forecasts at the zone substation level. We then reconciled our bottom-up and top-down connection point forecasts.

The modelling approach undertaken by CIE was consistent with the best practice methodology described by ACIL Allen in its 2013 report to AEMO for connection point forecasting.[222]

CIE's econometric modelling was underpinned by the same demand drivers that we understand to be used by AEMO, including price, population, income and weather. CIE made post-modelling adjustments for known changes in block loads and demand from major embedded generators. CIE's post-modelling adjustments for embedded generation, including windfarms and solar rooftop photovoltaic (**PV**) generation, were based on a report prepared by Oakley Greenwood.[223]

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220 CP PUBLIC ATT 9.4 - AER, *Explanatory statement, Expenditure forecast assessment guideline*, November 2013, pp. 262-267.

221 CP PUBLIC APP C, CitiPower, *Regulatory Proposal*, Appendix C Demand, energy and customer forecasts, April 2015.

222 CP PUBLIC ATT 8.5 - ACIL Allen Consulting, *Connection Point Forecasting, A Nationally Consistent Methodology for Forecasting Maximum Electricity Demand – Report to Australian Energy Market Operator*, June 2013.

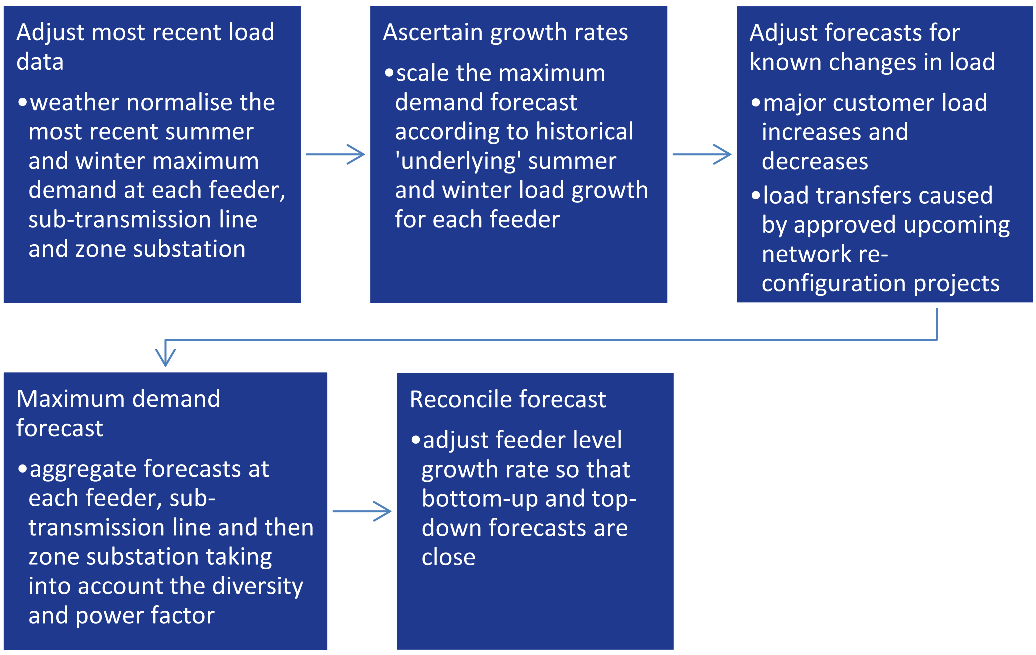
223 CP PUBLIC ATT 8.4 - Oakley Greenwood, *Summary and documentation of the terminal station impacts of five technology trends*, May 2014.

A detailed explanation of the methodology adopted by CIE is provided in its reports and CEPA's report.[224]

Our bottom-up forecasting process is shown in the figure below. Importantly, our bottom-up forecasts capture the underlying characteristics of areas serviced by local zone substations which cannot be captured through top-down modelling. Our bottom-up forecasts take into account:

- known connections based on connection applications and local planner enquiries;
- additions and reductions in block loads, for example supermarkets, residential apartment blocks, department stores and manufacturing plants;
- assessments of the diversification of load requirements and impacts on zone substation capacity; and
- the extensive knowledge and experience of our engineering and planning experts.

Figure 5.1 Bottom-up forecasting approach



Source: CitiPower

Finally, we reconciled our top-down forecasts of maximum demand at the connection point level and our internally developed bottom-up forecasts at the zone substation level by:

- adjusting down CIE's top-down forecasts where the baseline forecasts were inconsistent with the judgement of our expert network planners with strong local area network knowledge. This adjustment process is consistent with industry best practices outlined in the ACIL Allen report to AEMO on connection point forecasting;[225]

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[224] CP PUBLIC ATT 8.3 - CIE, *Maximum demand forecasting for CitiPower and Powercor*, July 2014. CIE, *Maximum demand forecasting for CitiPower and Powercor - 2015 update*, July 2015. CEPA, *Review of demand forecasting approaches*, December 2015.

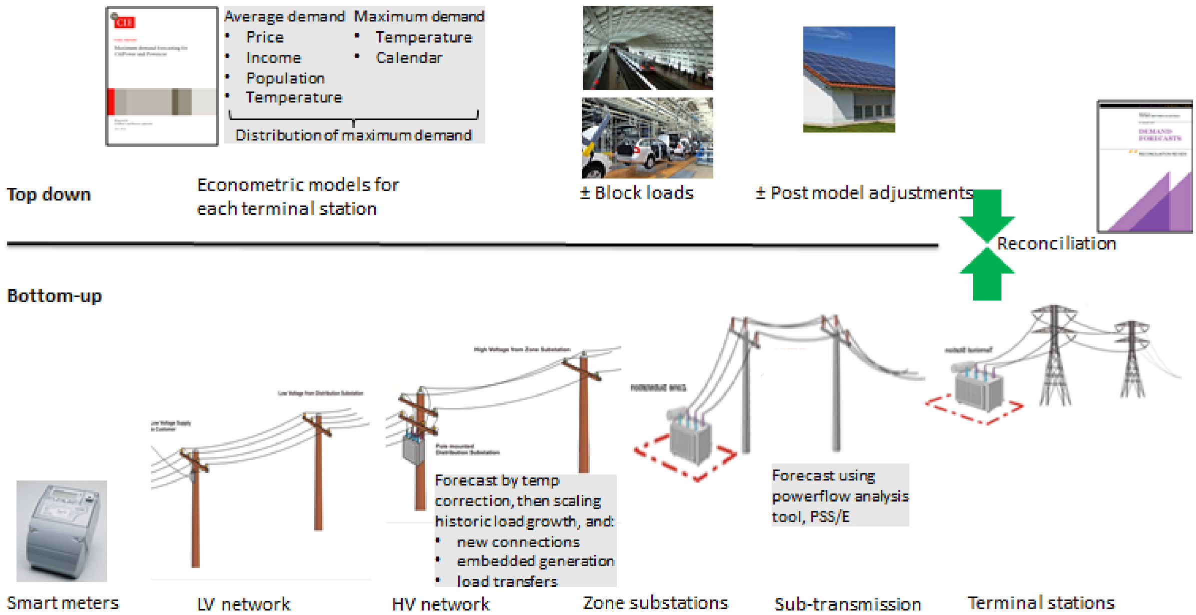
[225] CP PUBLIC ATT 8.5 - ACIL Allen Consulting, *Connection Point Forecasting – A Nationally Consistent Methodology for Forecasting Maximum Electricity Demand – Report to Australian Energy Market Operator*, June 2013.

- using diversity and power factors to aggregate the bottom-up forecasts to the connection point level for comparison with the top-down forecasts; and
- adjusting down our internal bottom-up forecasts where these exceeded the top-down forecasts.

Our reconciliation process was reviewed by ACIL Allen and found to be in accordance with best practice.[226]

Our methodology is demonstrated in the figure below.

Figure 5.2 Our forecasting methodology



Source: CitiPower

5.2.2 AER's preliminary determination

In its preliminary determination, the AER determined that our demand forecasts do not reasonably reflect a realistic expectation of demand over the 2016–2020 regulatory control period and that independent forecasts from AEMO were to be preferred.

The AER did not accept our demand forecasts because it considered that:[227]

- our forecasts of maximum demand are not consistent with, or explained by, long term demand trends and changes in the electricity market and the way energy is consumed in recent years;
- our forecasting method effectively assumes a fixed underlying relationship between demand and certain demand drivers, estimated over the past ten years, will continue to hold in the future. Therefore it is not clear that the demand drivers used in our model, or the way in which the model assumes these drivers affect demand, fully capture the changes in demand drivers in recent years; and
- in comparison with our demand forecasts, AEMO's independent connection point demand forecasts:[228]

[226] CP PUBLIC ATT 8.6 - ACIL Allen Consulting, *Demand Forecasts, Reconciliation Review, Report to CitiPower and Powercor Australia*, January 2015.

[227] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-109.

- better explain the actual demand patterns seen on all distributor's networks in recent years, in particular AEMO forecasts low or zero demand growth for 2016–2020 consistent with the AER's expectation that average demand growth is likely to be low, zero or negative in the 2016–2020 regulatory control period; and
- are derived using a methodology that does not assume a fixed structural relationship between demand and demand drivers over a long period. In particular, AEMO has adopted a cubic relationship to historical data, applied an 'off the point' approach (which means using the growth rates implied by the estimation of the historic trend but applying this trend from the most recent actual demand value) and placed greater reliance on industry knowledge and judgement.

On this basis, the AER rejected our demand forecasts and instead applied AEMO's 2014 connection point demand forecasts. In so doing, the AER stated that it would be open to considering updated demand forecasts and other information (such as AEMO's updated connection point forecasts) to reflect the most up to date data.

AER view that our forecasts do not reflect demand trends

The AER's preliminary determination did not accept our demand forecasts, in part, because it did not consider our forecasts to be consistent with, or explained by, the changes observed in electricity markets and recent declines in demand.

The AER stated that:

- from 2006 to 2009 actual maximum demand on our network was growing steadily but from 2009 to 2012 demand flattened and declined for our network, Victoria and the National Electricity Market (**NEM**), and, while there has been some growth in demand between 2013 and 2014, this does not necessarily indicate a return to longer term growth in demand;
- the following matters support forecast reductions or a softening of maximum demand even in the presence of continued economic and population growth and suggest that average demand growth is likely to be low, zero or negative in the 2016–2020 regulatory control period:
  - the uptake of rooftop PV in the residential and commercial sectors, which has reduced the electricity drawn from the grid in recent years, is forecast to continue in the 2016–2020 regulatory control period and beyond, with capacity expected to continue to grow in line with current levels of growth (albeit at the same time the AER observed that 'the impact of rooftop PV will likely have diminishing impacts on maximum demand over the longer term as peak daily demand shifts to the evening'[229]);
  - energy efficiency gains, which have also contributed to decreased electricity consumption in recent years, are also forecast to continue in the 2016–2020 regulatory control period, with the AER giving the example of the continued effect of government efficiency requirements in building provisions, greater customer awareness of energy usage, and improving appliance efficiencies and replacement of ageing appliances;
  - the decline in industrial consumption in Victoria in recent years is forecast to continue in the short term, due to the planned closure of vehicle manufacturing plants (albeit at the same time the AER acknowledged that this may be offset by growth in the residential sector, driven by population growth);
  - Victoria is not forecast to recover to its historical high level of operational consumption (in 2008/09) until 2030/31;

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[228] CP PUBLIC APP C.2 - AEMO, *Transmission Connection Point Forecasting Report for Victoria*, September 2014.

[229] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-116.

- other factors such as smart meter rollout, increased viability of battery technology and expected new tariff structures will likely further moderate maximum demand in the 2016–2020 regulatory control period (albeit at the same time the AER also observes in respect of battery storage that 'wide spread uptake of battery storage will probably not be significant over the 2016-20 period'[230]);
  - international trends, with growth in electricity demand currently low or zero in the United States of America (**USA**) and the United Kingdom (**UK**) despite the existence of continued population growth and economic growth suggesting that the impact of economic growth and population growth on electricity demand is being offset by other factors; and
- by contrast, our demand forecasts for the period 2015-2020 are considerably higher than actual demand observed on the network during the period 2006-2014 (substantially so for the 10 per cent Probability of Exceedance (**PoE**) forecasts), and forecast a return to demand growth on the network similar to that experienced prior to 2009.

AER view of our forecasting method

In its preliminary determination, the AER stated that our forecasting method effectively assumes a fixed underlying relationship between demand and certain demand drivers, estimated over the past ten years, will continue to hold in the future. The AER conclude therefore that it not clear the demand drivers used in our model, or the way in which the model assumes these drivers affect demand, fully capture the changes in demand drivers in recent years.

The AER came to this view on the basis of a report prepared by Darryl Biggar, an internal economic consultant from the Australian Competition and Consumer Commission.[231] The Biggar report reached the following conclusions regarding our forecasting approach:

- the CIE forecasting model, while econometrically sophisticated, assumes a fixed and unchanging underlying relationship between demand and demand drivers, estimated over a long period, will persist into the future;
- the CIE forecasting model only allows the temperature sensitivity of demand to vary in a particular linear way over the sample period;
- CIE have ignored the potential for saturation (where electricity demand ceases to rise once a particular temperature is reached) in their modelling which may upwardly bias their forecasts of peak demand;
- a lack of confidence that the models will accurately forecast peak demand in the near future, in particular because the models may not have fully captured recent and potential changes in demand, specifically:
  - energy efficiency trends (both increasing efficiency of houses and appliances);
  - the rapid growth in solar PV;
  - the impact of changing tariff structures;
  - de-industrialisation of the Victorian economy;
  - the potential for rapid growth in distributed energy resources, such as energy storage; and
  - the introduction by Victorian distributors of demand-based tariffs in the near future;

[230] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-116.

[231] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's demand forecasting methodology*, September 2015.

- CIE's model predicts demand will grow strongly in the future, this does not seem likely, rather average demand growth is likely to be low, zero or negative in the future given the recent and potential changes in demand;
- CIE's model does not allow for the possibility that the responsiveness of average demand to demand drivers, such as population and income factors, will vary over time; and
- CIE's forecasts are now more than one year old and were prepared before the most recent summer, with the result that updated forecasts by CIE may be different.

As a consequence, Biggar expressed concern that our demand forecasts are not a realistic expectation of future demand.

AER view of AEMO's forecasting method

Finally, the AER's approach to assessing our demand forecasts was based substantially on a comparison of our forecasts with AEMO's 2014 connection point demand forecasts.

The AER's assessment is that, in comparison with our forecasts, AEMO's 'independent' forecasts:[232]

- predict low or no growth (while we forecast strong positive growth) and so are more consistent with the AER's expectation that average demand growth is likely to be low, zero or negative in the 2016–2020 regulatory control period; and
- are more likely to reflect a realistic expectation of demand because, in contrast to our methodology, its forecasts are derived using a methodology that:
  - does not assume a particular long term structural relationship for demand over time;
  - fits a cubic relationship to historical data; and
  - applies an 'off-the-point' approach, developed by ACIL Allen, which:
    - extrapolates the relationship between demand and long term underlying drivers based on the most recent actual demand value; and
    - relies on industry knowledge and judgement to adopt an alternative to a historical linear trend.

While the Biggar report did not purport to assess AEMO's methodology nor express any preference for it over that of CIE, it did raise concerns relating to AEMO's methodology, particularly in relation to the off-the-point approach and fitting a cubic trend to historical data. However, the AER does not place any weight on, indeed disregards, Biggar's findings on AEMO's forecasting method.

5.2.3 Our response to the AER's preliminary determination

We have updated our forecasts following 2014–2015 summer

The AER's preliminary determination states that its forecasts should reflect the most current expectations of demand for the forecast period and it will consider updated demand forecasts from distributors and AEMO in making its final determination.[233] Similarly Biggar's report notes that CIE's forecasts are now more than one year

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232 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 6-121 to 6-122.

233 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-109.

old and were prepared before the most recent summer, with the result that updated forecasts by CIE may be different.[234]

Our regulatory proposal was based on forecasts that were prepared in winter 2014 for the purposes of the 2014 Distribution Annual Planning Report (**DAPR**), published in December 2014.

For our revised regulatory proposal we have updated our demand forecasts to include the most recent summer (summer 2014–2015). Our updated forecasts were prepared for the purposes of our DAPR published in December 2015 and are used by the business for establishing whether additional capacity is required at a location and to assess the augmentation options to address forecast network constraints.

Updating our maximum demand forecasts involved:

- engaging CIE to update its top-down demand forecasts for actual 2014/2015 summer demand, updated information on demand drivers, updated forecasts of the impact of technologies by Oakley Greenwood,[235] and updated information on block loads. CIE used the same forecasts of Gross State Product (**GSP**) and retail electricity price as AEMO's 2015 state-wide demand forecasts;[236]
- updating our internal bottom-up forecasts for more recent demand data and local information; and
- reconciling the top-down and bottom-up forecasts using the same approach as for our 2014 forecasts.

Our updated demand forecasts are lower than our initial proposal forecasts due to reductions in the forecast demand drivers including GSP and retail electricity prices.[237] As shown in the following figure, we forecast a moderate growth in maximum demand.

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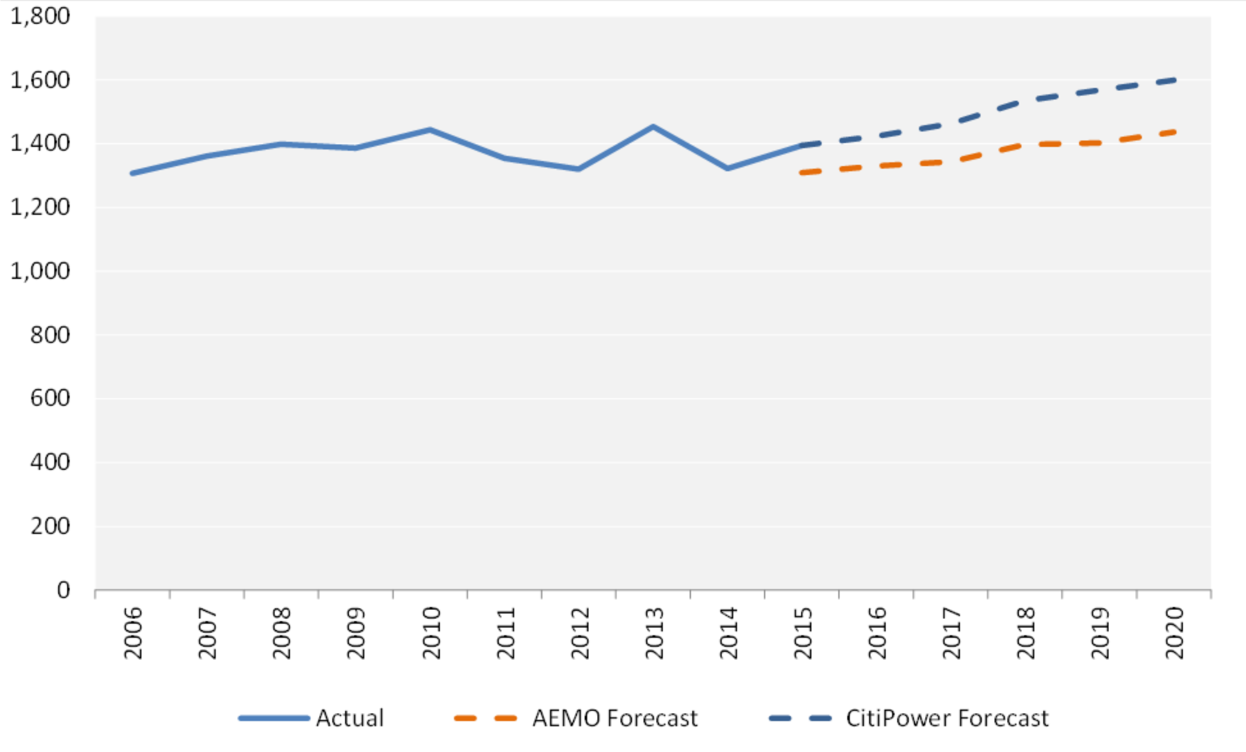
[234] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's demand forecasting methodology*, September 2015, p. 27.

[235] Oakley Greenwood, *Metadata analysis of disruptive technologies on CitiPower and Powercor demand forecasts,* June 2015.

[236] CIE, *Maximum demand forecasts for CitiPower and Powercor - 2015 update*, July 2015, p.2.

[237] CIE, *Maximum demand forecasts for CitiPower and Powercor - 2015 update*, July 2015, pp. 7-8.

Figure 5.3 Non-coincident transmission connection point summated weather corrected maximum demand, MW, 50% POE



Source: CitiPower, AEMO 2015 transmission connection point forecasts.
Note: A positive value means the distributor forecast was higher than AEMO's.
Non-coincident demand reflects the spatial nature of demand which is the relevant comparator for the purposes of assessing capital augmentation and expenditure requirements.

Notably, the AER accepted demand forecasts prepared by the distributors in New South Wales (**NSW**), Australian Capital Territory (**ACT**) and Queensland (**QLD**) on the basis that these were relatively consistent with AEMO's connection point forecasts.[238] Our analysis demonstrates that our forecasts are no more different to AEMO's than the NSW, ACT and QLD distributors, as shown in the table below. It would therefore be inconsistent for the AER to accept the forecasts of distributors in NSW, ACT and QLD and reject our forecasts.

238 AER, *Final decision Ausgrid distribution determination, 2015-16 to 2018-19, Attachment 6*, April 2015. AER, *Final decision Endeavour Energy distribution determination, 2015-16 to 2018-19, Attachment 6*, April 2015. AER, *Final decision Essential Energy distribution determination, 2015-16 to 2018-19, Attachment 6*, April 2015. AER, *Final decision Ergon Energy distribution determination, 2015-16 to 2019-20, Attachment 6*, April 2015. AER, *Final decision Energex distribution determination, 2015-16 to 2019-20, Attachment 6*, April 2015. AER, *Final decision ActewAGL distribution determination, 2014-15 to 2018-19, Attachment 6*, April 2015.

Table 5.1 Non-coincident transmission connection point summated weather corrected maximum demand, MW

Distributor	10% POE, Per cent difference between distributor forecast and AEMO forecast (annual average)	50% POE, Per cent difference between distributor forecast and AEMO forecast (annual average)
Ergon	12%	12%
Energex	14%	9%
Essential	9%	11%
Endeavour	13%	16%
AusGrid	16%	18%
ActewAGL	3%	5%
CitiPower	6%	9%

Source: AEMO 2014 Transmission connection point forecasts for NSW, ACT and Tasmania, AEMO 2015 Transmission connection point forecasts for QLD and AEMO 2015 Transmission connection point forecast for Victoria. Ergon, Energex, Essential, Endeavour, AusGrid and ActewAGL Reset RINs and CitiPower Revised Reset RIN.

Note: A positive value means the distributor forecast was higher than AEMO's.
Non-coincident demand reflects the spatial nature of demand which is the relevant comparator for the purposes of assessing capital augmentation and expenditure requirements.

Importantly, over the 2016–2020 regulatory control period, we expect demand to grow at a faster rate in specific areas of our network, driven by:

- transfer of loads around the network due to the retirement of the 22kv sub-transmission network;
- population expansion, particularly along established and proposed transport corridors driven by zoning changes; and
- block load additions from specific projects, for example supply for public transport infrastructure projects.

AEMO's forecasting approach, which is based on historical trends and does not incorporate industry knowledge, is unable to capture the impact on forecast demand growth from these location specific changes.

Our forecasts better meet the requirements in the Rules and Law than AEMO's

Our demand forecasting methodology is robust and reliable and provides the best estimate of demand for standard control services in the 2016–2020 regulatory control period. We consider that our updated demand forecasts reflect a realistic expectation of demand forecasts. Accordingly, the AER should accept our updated demand forecasts in accordance with clauses 6.5.6(c), 6.5.6(c), 6.12.1(3)(ii) and 6.12.1(4)(ii) of the Rules.

We engaged CEPA to assess our forecasts and AEMO's forecasts against the requirements in the Rules and the Law. CEPA concludes that:[239]

> *After reviewing both AEMO's and the Businesses' approaches we consider that the Businesses' approach to demand forecasting at the connection point level is more likely to achieve the NER and hence the NEO than AEMO's.*

[239] CEPA, *Review of demand forecasting approaches*, December 2015, pp. iv and 36.

Key reasons for CEPA's conclusion are:[240]

The Businesses' model includes economic and population drivers at the connection point level, while AEMO's methodology relies on a simple trend either using time or population and an adjustment to the system level forecasts for economic drivers. In our opinion the Businesses' methodology should lead to more accurate connection point level forecasts.

The Businesses' model validates bottom-up estimates with top-down estimates at the DNSP level, while AEMO's reconciliation is done at the state-wide level. AEMO overrides its bottom-up estimates of growth with its top-down estimates of growth at the state level from year two. As AEMO's approach does not take into account the socio-economics of the residential and commercial connections below each connection point for the respective DNSPs its estimates may not reflect the DNSPs' augmentation expenditure and opex requirements.

The Businesses incorporate their local knowledge of the demand at the connection points into their forecasts.

Based on CEPA's assessment of both forecasting approaches it is clear that our demand forecasts provide a more realistic expectation of demand at the connection point level than AEMO's. Realistic demand forecasts at the spatial level are essential for identifying network constraints and network augmentation requirements. As acknowledged by the AER:[241]

Localised demand growth (spatial demand) drives the requirements for specific growth projects or programs. Spatial demand growth is not uniform across the entire network[.]

and by CEPA:[242]

We believe that the most appropriate consideration when assessing the demand forecasts is to ascertain which one(s) best incorporate the actual drivers for augmentation expenditure and, to a lesser extent, opex. From a network planning and augmentation expenditure perspective maximum demand at connection point forecasts provide a far better indication of requirements than a state-wide forecast. The AER rightly refers to these spatial demand forecasts as the key drivers for specific growth project or programmes, while the overall system level demand give a high level indication only.

Therefore it would seem to us that the approach which best models the drivers for demand at the connection points would be more appropriate for meeting the NEO as long as the system-wide forecast was also robust.

Our demand forecasts therefore ensure our proposed capital expenditure and operating expenditure forecasts are efficient and prudent in accordance with the Rules.

Response to AER reasons for rejecting our forecasts and substituting for AEMO's forecasts

The AER incorrectly concludes that:

- our demand forecasts do not reflect a realistic expectation of demand; and
- AEMO's forecasts do provide a realistic expectation of demand.

Our reasons are set out in detail in the following sections and summarised in the following table.

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[240] CEPA, *Review of demand forecasting approaches*, December 2015, p. iv and 36.

[241] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-108.

[242] CEPA, *Review of demand forecasting approaches*, December 2015, pp. iv and 35-36.

Table 5.2 Summary of our response to AER's preliminary determination

AER preliminary decision	Our response
Our forecasts reflect a realistic expectation of demand	
AER concludes that our forecasts do not reflect recent and future changes in demand trends	Our forecasts reflect the recent changes in demand trends because: • we use the most recent ten years of data to develop our forecasts. The changes in demand trends cited by the AER occurred during the most recent ten years. Therefore our forecasts already capture the impact on forecast demand of the changes in electricity market conditions to the extent that these changes continue to grow at the same rate as in recent history; • we made post-modelling adjustments to take account of changes in electricity market conditions that are reasonably expected to have a greater impact on demand during the forecast period than in recent history. We made post-model adjustments for embedded generation, including solar PV and windfarms, known planned closures of manufacturing plants affecting connection points in our network area and limiting the growth of highly industrial connection points to zero.
AER concludes that demand will continue to soften or reduce while our forecasts predict increasing demand	The AER has no basis for concluding that demand growth on our network will continue to soften or reduce during the forecast period. The AER provides no evidence to substantiate its statement. Comparison with international markets is irrelevant as it is localised demand growth that drives the requirement for specific growth projects of programs. Local demand growth is dependent on local demand characteristics and local demand drivers. The AER appears to rely on AEMO's 2014 demand forecasts to form its view. Notably AEMO has significantly revised up its connection point demand forecasts in 2015.

<table>
<tr><th>AER preliminary decision</th><th>Our response</th></tr>
<tr><td colspan="2">AEMO's forecasts do not reflect a realistic expectation of demand</td></tr>
<tr><td>AER reasons for preferring AEMO forecasts include:
• no structural relationship between demand and demand drivers;
• use of a cubic relationship and off-the-point approach; and
• reliance on industry knowledge and judgement.</td><td>AEMO's forecasts are based on a structural relationship between:
• demand and time for the baseline connection point forecasts; and
• demand and economic demand drivers for the state-wide forecasts used to reconcile the final connection point forecasts.
The AER provides no explanation for how it considers AEMO's use of a cubic relationship between demand and time and the off-the-point approach ensures that forecasts reflect a realistic expectation of demand. These approaches are controversial and raise doubt over the appropriateness of the forecasts.
The AER has provided no explanation of how it considers AEMO has relied on industry knowledge and judgement in forming its forecasts. None of the expert consultants were able to advise how AEMO has captured industry knowledge in its forecasts.
Importantly, our forecasts rely on industry knowledge including our expert engineering knowledge at the zone substation level and our local knowledge of demand conditions.</td></tr>
<tr><td>AER made no assessment of AEMO's forecasts against its own best practice demand forecasting principles.</td><td>CEPA found our approach better meets the AER's best practice demand forecasting principles.
CEPA considered that, in the context of the achievement of the NEO and Rules, the greatest weight should be placed on the principles:
• incorporation of key drivers;
• spatial (bottom-up) forecasts validated by independent system level (top-down) forecasts;
• weather normalisation; and
• accuracy, unbiasedness and testing.
These are the principles where CEPA found our approach to be preferable to AEMO's.
Further, AEMO's approach lacks the level of transparency necessary for stakeholders, including the AER, to fully assess the robustness of the forecasts.</td></tr>
</table>

Source: CitiPower

5.2.4 Our forecasts reflect a realistic expectation of demand

We dispute the AER's conclusion that our forecasts do not reflect a realistic expectation of demand. The AER's conclusion is premised on three factors:

- that our forecasting approach effectively assumes a fixed underlying relationship between demand and demand drivers and that this relationship will hold into the future;
- our forecasting approach is unable to fully capture the recent and future changes in demand because it effectively assumes a fixed relationship, estimated over the past ten years, holds in the future; and
- demand is expected to soften or reduce in the 2016–2020 regulatory control period, while we forecast strong positive growth.

We dispute the AER's conclusions for the reasons set out in the following sections, specifically:

- our forecasts fully reflect recent changes and reasonably expected future changes in electricity markets and demand drivers; and
- the AER has no basis for its assertion that maximum demand will soften or reduce.

We engaged CIE to review the AER's reasons for rejecting our demand forecasts, as set out in its preliminary determination and the Biggar report.[243]

Our forecasts fully reflect recent and future changes in electricity markets and demand drivers

Our top-down forecasting method is based on econometric models developed by CIE using ten years of historical data over the period 2004 to 2015 summer. Using the most recent ten years of data to establish the relationship between demand and demand drivers ensures that our methodology directly takes into account changes in energy market conditions that occurred in recent history. Importantly, most of the changes in electricity markets identified by the AER occurred during the most recent ten years and are therefore captured in the historical data used to develop our forecasts, including:

- energy efficiency measures for appliances and buildings occurred either before or during the early years of our historical sample period. Changes in building requirements commenced in 2003 with more stringent requirements in 2006 and 2010.[244] Further, there is mixed evidence as to whether energy efficiency changes have impacted on maximum demand;[245]
- the Sadler report for the Australia Institute places the change in energy patterns at 2006, noting a significant reduction change in the income elasticity from 2006. The post 2006 elasticity's derived by Sadler are relatively similar to those estimated by CIE.[246] This is not surprising given 2006 is early in the historical period used to develop our demand forecasts;
- solar PV capacity accelerated from 2009.[247] Again this is well within the historical period used to develop our forecasts. Further, as discussed below, we have made an additional post-modelling adjustment for an increased impact on maximum demand from solar PV; and
- air conditioning penetration is taken into account through the interaction term between calendar years and temperature which allows the responsiveness of the peak/average demand ratio to vary at the upper end of the temperature curve.[248]

Therefore, our methodology captures the impact of the above factors on forecast demand during the 2016–2020 regulatory control period, to the extent the rate of growth in these factors continues at the same rate as over the past ten years.

This is further evidenced by CIE's quantitative analysis which demonstrates there would be very small differences in forecast demand for our network under the different sample periods 2004–2014 and 2009–2014, as shown in the table below.[249] CIE also found no definitive evidence of a uniform change in energy consumption behaviour

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243 CIE, *Review of Assessment of forecasts by Darryl Biggar and AER*, December 2015.

244 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-117.

245 CIE, *Review of Assessment of forecasts by Darryl Biggar and AER*, p. 16.

246 CIE, *Review of Assessment of Forecasts by Darryl Biggar and AER*, December 2015, p. 15.

247 AER, *Preliminary decision, CitiPower distribution determination2016–20,* October 2015, Figure 6.24, p. 6:116.

248 CIE, *Maximum demand forecasting for CitiPower and Powercor - 2015 update*, p. 32.

249 CIE, *Review of Assessment of Forecasts by Darryl Biggar*, December 2015, p. 16.

in the relationship between demand and demand drivers.[250] The AER therefore has no basis to conclude that our forecasts do not reflect recent changes in electricity markets.

Table 5.3 Starting point and average demand growth under different sample periods

Estimation period	2004–2014	2009–2014	Difference
Starting point (summer 2016)	913 MW	918 MW	0.50%
Annual growth rate (2016–2020)	1.63	1.68	0.05

Source: CIE, *Review of Assessment of Forecasts by Darryl Biggar*, December 2015, p. 17.

In addition, our forecasting methodology includes post-model adjustments for factors that are likely to have a greater impact on demand in the forecast period than in the most recent ten years (i.e. the growth rate will be faster in the next five years than over the last ten years), including:

- embedded generation - our forecasting approach includes post-modelling adjustments for an increased impact on forecast maximum demand of embedded generation, including solar PV and windfarms. CIE's post-modelling adjustments for solar PV were based on analysis independently prepared by Oakley Greenwood.[251] Notably, our post-model adjustment for solar PV reduces annual demand growth by 0.66 percentage points which is a greater reduction in annual demand growth than AEMO's post-model adjustment of 0.61 percentage points.[252] Our forecasting approach therefore already factors in the expected impact on maximum demand from an acceleration in the uptake of embedded generation, particularly solar PV, and the AER has no basis to justify rejecting our forecasts in favour of AEMO's on the basis of solar PV;
- industrial sector changes - our forecasting approach includes post-model adjustments for:
  - block loads relating to known planned closures of manufacturing plants affecting connection points in our network area. Our local presence in the network area and our close relationship with large industrial customers means we have a strong understanding of the expected material changes in manufacturing sector demands over the 2016–2020 regulatory control period; and
  - connection points with high industrial loads are limited to zero growth from industrial demand. This ensures we are conservative in our forecasts of demand growth from the industrial sector; and
- tariff impacts - our forecasting approach allows for an acceleration in the uptake of time of use tariffs which lead to different prices for each of the four six hour periods that we model. This means our forecasts already include a reduction in maximum demand to account for an increased responsiveness of customers to peak demand price signals and therefore provides a proxy for demand tariffs.

Our forecasting approach does not include additional adjustments for factors that are unlikely to have a material impact on demand during the 2016–2020 regulatory control period. It would be imprudent and inconsistent with the Rules for our forecasts to include changes in the electricity market which are unlikely to occur with a reasonable level of certainty, and doing so would not provide us with a reasonable opportunity to recover at least our efficient costs. We therefore did not include additional adjustments to our forecasts for:

- an additional impact of energy efficiency - as noted above, we have already captured the impact of energy efficiency in our forecasts to the extent that future changes occur at the same rate as over the past ten years.

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[250] CIE, *Review of Assessment of Forecasts by Darryl Biggar*, December 2015, p. 16.

[251] Oakley Greenwood, *Metadata analysis of disruptive technologies on CitiPower and Powercor demand forecasts,* June 2015.

[252] CIE, *Review of Assessment of Forecasts by Darryl Biggar and the AER*, December 2015, p. 22.

CIE did not include additional adjustments as there is uncertainty whether new energy efficiency programs will be introduced during the 2016–2020 regulatory control period and, if so, whether the impact on demand would be greater than already captured in the forecasts through the historical trends. Notably, AEMO's energy efficiency post-model adjustment applied to its 2015 state-wide and connection point forecasts reduce annual growth in maximum demand by only 0.08 percentage points.[253] This is an immaterial adjustment and provides no basis for the AER to reject our forecasts in favour of AEMO's. Further, AEMO's adjustment for energy efficiency in its 2014 forecasts was overstated due to double counting of the energy efficiency already captured in historic trends.[254] AEMO corrected this in its 2015 forecasts;

- electric vehicles and battery storage - analysis prepared by Oakley Greenwood indicated the impact on maximum demand of these measures is small and uncertain and, in the case of battery storage, not expected to have an effect on demand during the 2016–2020 regulatory control period.[255] The AER's preliminary determination also acknowledges that the uptake of battery storage is unlikely to be significant over the 2016–2020 regulatory control period.[256] Nevertheless, CIE has assessed the anticipated impact on our maximum demand forecasts if we were to include a post-model adjustment. CIE found these to be immaterial:[257]
  - electric vehicles would increase average annual growth by between 0.01 and 0.02 percentage points; and
  - battery storage would decrease average annual growth by between 0.0 and 0.9 percentage points.

  Further, AEMO's forecasts do not include post-model adjustments for electric vehicles or battery storage. The AER therefore has no justification for substituting our forecasts for AEMO's on the basis of future potential developments relating to electric vehicles or battery storage;
- new distribution tariff structures - the Rule requirement to develop cost reflective distribution tariff structures will not have a material impact on maximum demand during the 2016–2020 regulatory control period, because:
  - new distribution tariff structures are not effective until 2017 and are being gradually phased in through to 2021;[258]
  - new distribution tariff structures are not required to be replicated by retailers and therefore there is no certainty that customers will receive cost reflective price signals regarding demand for electricity;
  - there is uncertainty regarding how customers will respond to any price signals that are passed on through changes in retail prices, noting that our distribution charges make up only 20 per cent of the retail bill;[259]
  - the Victorian Government has advised that in Victoria demand tariffs will be subject to an opt-in requirement for the 2017–2020 period.[260] This will reduce the take up of cost reflective tariffs relative to an opt-out policy; and

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[253] CIE, *Review of 2015 AEMO Transmission connection point forecasts and methodology*, December 2015, p. 49.

[254] Our concerns with AEMO's 2014 energy efficiency adjustments are set out in the following attachments to our regulatory proposal: CP PUBLIC ATT 8.9 - CIE and Oakley Greenwood, *Review of AEMO transmission connection point forecasts*, January 2015 and CP PUBLIC ATT 8.7, *GHD Review of AEMO forecasting methodology*, January 2015.

[255] Oakley Greenwood, *Metadata analysis of disruptive technologies on CitiPower and Powercor demand forecasts*, June 2015, pp. 7-14.

[256] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 6-116.

[257] CIE, *Review of Assessment of Forecasts by Darryl Biggar and the AER*, December 2015, p. 13.

[258] CitiPower, *Tariff Structure Statement 2017–2020, Overview paper*, September 2015, p. 9.

[259] Oakley Greenwood, *CitiPower pricing comparisons*, 1995 to 2014, December 2014, p.5.

[260] Minister for Energy and Resources, *Distribution network pricing arrangements*, November 2015.

- the Australian Energy Market Commission (**AEMC**) clearly states that its expectation that more cost-reflective pricing may be expected to reduce the need for network augmentation is a long term expectation;[261]

- advanced metering infrastructure (**AMI**) - the impact of AMI on maximum demand is dependent on customer responsiveness to cost reflective tariffs. As noted above, the introduction of new tariff structures will not have a material impact on maximum demand during the 2016–2020 regulatory control period.

Notably, AEMO does not make allowances in its modelling approach for the potential impact of changes in distribution tariff structures or AMI data. Therefore the AER cannot justify substituting our forecasts for AEMO's on this basis.

In conclusion, the AER's concern that our forecasting approach does not reflect recent and potential future changes in electricity markets has no basis. Neither the AER nor the Biggar report provide any evidence to substantiate that the impact on forecast maximum demand of recent or potential future changes in the electricity market will exceed the impact already captured in our forecasts. Notably, the Biggar report makes a number of factual errors in his assessment of CIE's methodology, these are set out in CIE's response to the Biggar report.[262]

The AER has therefore erred in its assessment that our forecasting approach does not adequately reflect recent or future changes in energy market conditions that are reasonably expected to impact demand forecasts over the 2016–2020 regulatory control period.

The AER has no basis for the conclusion that demand will soften or reduce

The AER has made an error in its assessment that the identified changes in market conditions will lead to a softening or reduction in maximum demand in 2016–2020. The matters relied on by the AER in support of its conclusion do not suffice to establish that proposition. The AER makes no attempt to quantify the impact of solar PV uptake, energy efficiency gains, de-industrialisation, smart meter rollout, battery technologies or expected new tariffs on demand over the 2016–2020 regulatory control period. The AER makes no attempt to seek to determine whether, and the extent to which, these changing market conditions will offset the impact on demand of expected economic and population growth (with which the AER does not take issue and would appear to accept).

The AER itself acknowledges that the impact of a number of the changing market conditions it cites will have negligible impact on demand in the 2016–2020 regulatory control period. In particular, the AER concludes that the uptake of battery technology over the 2016–2020 period is not expected to be significant and the impact of solar PV uptake on maximum demand is likely to diminish as peak daily demand shifts to the evening.[263]

Further, the Biggar report appeared to concede that it is difficult to predict the directional impact of distributed generation on demand, noting that:[264]

> *The role of electricity networks in this transformation is uncertain. On the one hand the increase in distributed generation should reduce demand for network services, but it is possible that the role of distribution networks will change to facilitate a two-way flow of trade in electricity. The key point here is that the future path of the electricity industry is more uncertain than at any time in the last 20 years.*

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[261] AEMC, *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014: Rule determination*, November 2014, p. 8.

[262] CIE, *Review of Assessment of Forecasts by Darryl Biggar and the AER*, December 2015.

[263] AER, *Preliminary decision, CitiPower distribution determination 2016–20, October 2015*, p. 6-116.

[264] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's demand forecasting methodology*, September 2015, p.3.

The AER's reference to international aggregated electricity consumption trends does not provide probative evidence of future maximum demand growth on our network over the 2016–2020 regulatory control period. As acknowledged by the AER, it is localised demand growth that drives the requirement for specific growth projects or programs. Local demand growth is dependent on local demand characteristics and local demand drivers. Observations from the USA and UK are not informative for assessing a realistic expectation of demand at connection points in our network.

The AER's assertion that these factors contribute to a reduction in demand during the 2016–2020 regulatory control period is based purely on speculation.

Additionally, neither the AER nor the Biggar report evaluate the impact of changes in retail electricity prices on forecast maximum demand. Over the past decade, real retail electricity prices in Victoria have increased significantly, an annual average growth rate of 4.2 per cent per annum, which has placed a drag on demand.[265] However, current market expectations are that electricity retail prices will soften and therefore, all else equal, demand would be expected to rebound.

As noted above, to the extent that we consider the changing market conditions are reasonably expected to impact on maximum demand in the 2016–2020 regulatory control period, we have already factored these into our forecasts through the use of historical trends and post-modelling adjustments. Our demand forecasts therefore already take account of the impact on forecast maximum demand of recent and future expected changes in market conditions.

5.2.5 AEMO's forecasts do not provide a realistic expectation of demand

We dispute the AER's conclusion that AEMO's connection point forecast is more likely to reflect a realistic expectation of demand over the 2016–2020 regulatory control period. The AER's conclusion is based on its view that AEMO's forecasting approach:

- does not assume a fixed structural relationship between demand and demand drivers;
- has adopted a cubic relationship, an off-the-point approach and relies on industry knowledge and judgement; and
- results in forecasts of low or zero growth over the 2016–2020 regulatory control period.

In the preliminary determination the AER refers to the ACIL Allen methodology which was recommended to AEMO. If the AER is to substitute our forecasts for AEMO's, it must assess whether AEMO's forecasts reflect a more realistic expectation of demand based on the methodology actually applied by AEMO, not what was recommended by ACIL Allen.

We dispute the AER's conclusions for the reasons set out in the following sections, specifically:

- the AER has erred in its reasons for concluding AEMO's forecast approach better reflects a realistic expectation of demand;
- our approach better meets the AER's best practice demand forecasting principles than AEMO's; and
- AEMO's forecasts do not provide a realistic expectation of demand relevant to our network area and therefore do not reflect the demand forecasts that are relevant to our capital expenditure requirements.

Therefore, AEMO's connection point demand forecasts do not provide a realistic expectation of demand, and, according if adopted, will result in expenditure forecasts that are below the expenditure required to meet the

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[265] CIE, *Review of Assessment of Forecasts by Darryl Biggar and AER*, December 2015, p. 19.

operating expenditure and capital expenditure objectives in the Rules. In particular, the expenditure allowance will not be sufficient to enable us to meet or manage the expected demand for standard control services. It is therefore not open to the AER to substitute our forecasts with AEMO's connection point forecasts.

Our detailed reasoning is set out in the following sections.

We note that while the AER's preliminary determination applied AEMO's 2014 connection point forecasts. For the final determination, the AER may seek to assess our updated 2015 forecasts with AEMO's 2015 forecasts. We engaged GHD and CIE to update their review of AEMO's 2014 forecasts for changes in AEMO's 2015 forecasting approach.[266] Importantly, while AEMO has made some incremental changes to its forecasting methodology for its 2015 forecasts, the general approach remains largely unchanged from 2014. Our concerns with AEMO's approach and the AER reasons for applying AEMO's forecasts therefore apply to both AEMO's 2014 and the 2015 forecasts, except where explicitly noted otherwise.

AER has erred in its reasons for concluding AEMO's forecasts better reflects a realistic expectation of demand

<u>AEMO applies a structural relationship between demand and demand drivers</u>

The AER is incorrect in its statement that a reason for preferring AEMO's methodology is because it does not assume a fixed relationship between demand and demand drivers. AEMO's methodology involves:

- forecasting baseline connection point demand assuming a fixed relationship between demand and time based on historical trends. While AEMO forecasts off-the-point, it still uses the historical growth rates to develop the demand forecasts from the most recent actual data point;
- forecasting state-wide demand assuming a fixed relationship between state-wide demand and state-wide economic demand drivers. The relationship between demand and demand drivers estimated by AEMO at the state-wide level is based on the period 2002–2015 which is a longer historical period than used by CIE. Additionally, unlike CIE, AEMO's model does not allow for the relationship between temperature and demand to change over time;
- reconciling the connection point forecasts to match the state-wide forecasts. AEMO's reconciliation process has the effect of overriding AEMO's baseline connection point forecasts with a simple proportional allocation of the difference in growth rates between the state-wide forecasts and summated connection point forecasts.[267] Consequently, AEMO's connection point forecasts inherit the historical relationships between state-wide demand and state-wide demand drivers.

Therefore, the AER's assertion that AEMO's forecasts do not assume a fixed structural relationship between demand and demand drivers is incorrect.

The AER has no justification for substituting our forecasts for AEMO's on the basis that our forecasting approach assumes a fixed relationship between demand and demand drivers because this criticism is also applicable to AEMO's forecasting approach.

[266] GHD, *AEMO Demand Forecast Review (2015 update)*, December 2015 and CIE, *Review of 2015 AEMO Transmission connection point forecasts and methodology*, December 2015.

[267] For the 2014 forecasts AEMO's reconciliation was based on the difference in the level of demand between the state wide and summated connection point forecasts. For the 2015 forecasts AEMO changed its approach to reconcile based on the difference in growth rates.

AEMO's cubic relationships and off-the-point approach does not ensure forecasts reflect realistic demand expectations

We dispute the AER's view that AEMO's forecasting approaches of using cubic relationships and an off-the-point approach means the forecasts are likely to result in a more realistic expectation of demand.

First, AEMO's use of an off-the-point approach:

- was only recommended by ACIL Allen in circumstances where there is a valid reason for starting off the point. ACIL Allen state:[268]

  If no valid reason to support starting 'off the point' can be found, it is reasonable to conclude that the difference between the 'point' and the 'line' is due to randomness in the data. In this case, starting 'off the line' is preferred over assuming that the same random outcome will be repeated in every forecast year.

  AEMO's only reason for forecasting off-the-point is because the time trend does not fit the data well. This raises concerns over the forecast growth rates which are based on the historical time trend, as discussed below;

- is indicative that the method for forecasting the trend is inadequate for explaining the growth in demand, yet the same trend is still used to develop the forecasts. These concerns are raised by a number of consultants, for example:

  Frontier states:

  from a statistical point of view, "off the point" should only be used as the starting point if the linear time trend regression model is not well specified, and hence does not provide a good indication of future maximum demand.

  The Biggar report, prepared for the AER, states:[269]

  One problem with the "off-the-point" approach is that it is theoretically inconsistent with the assumptions that underlie the use of a linear extrapolation in the first place. The use of a linear extrapolation essentially assumes that all departures from the long term linear trend reflect pure temporary statistical noise. If this is the case the use of the most recent point (which is itself assumed to be just a temporary departure from the long term trend) as the starting point for the future forecasts cannot improve those forecasts.

  GHD states:[270]

  AEMO have applied this technique to compensate for a perceived structural break, without exploring the underlying reasons….If the energy model cannot fully explain the recent downturn in electricity demand, then a considered response might be to review the specification of the model, including whether the log-log form is the most appropriate and additional drivers that should perhaps be included.

  CIE states:[271]

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[268] CP PUBLIC ATT 8.5 - ACIL Allen Consulting, *Connection point forecasting, A Nationally consistent methodology for forecasting maximum electricity demand*, p. xvii.

[269] Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's demand forecasting methodology*, September 2015, p. 12.

[270] CP PUBLIC ATT 8.7 - GHD, *Review of AEMO Demand Forecasting Methodology*, January 2015, p. 17.

Forecasting off-the-point implies that future estimates incorporate error in weather normalisation and randomness in actual demand outcomes.

- is highly controversial, subject to a number limitations and places significant weight on the last observation, which if it turns out to be just an abnormality will significantly bias the forecasts across the period.

Secondly, AEMO's use of a cubic relationship only applied to its 2015 connection point forecasts not the 2014 forecasts applied by the AER in the preliminary determination. The cubic relationship between demand and time is of limited value as it does not take into account any of the drivers of demand that are expected to impact on future demand.

The Biggar report, prepared for the AER, states:[272]

> *The problem here is that the choice of a cubic polynomial is arbitrary in the sense that it is not justified on the basis of knowledge of the underlying economic phenomena or industry drivers. The use of a cubic time trend provides a better statistical fit to the data but raises the question why it is reasonable to assume that this cubic relationship will continue into the future?*

CIE states:[273]

> *The model is a time based model. It allows for no factors at all to influence demand except for time, It is difficult to see how this model could better account for the drivers of demand that Biggar report considered were not included by Distributors, as it has no explicit drivers.*

CEPA states:[274]

> *The Businesses' model includes economic and population drivers at the connection point level, while AEMO's methodology relies on a simple trend either using time or population and an adjustment to the system level forecasts for economic drivers. In our opinion the Businesses' methodology should lead to more accurate connection point level forecasts.*

It is clear that AEMO's approach of applying a simple time based trend, whether cubic or linear, does not provide an informed basis for forecasting future demand at the connection point level. Accurate forecasts at the connection point level are critical to forecasting our capital augmentation requirements to ensure expenditure is deployed where demand is expected to place the greatest pressure on existing infrastructure.

Finally, the AER's unexplained preference for cubic and off-the-point approaches are only related to AEMO's baseline connection point forecasts. However, as discussed below, AEMO's reconciliation process results in the baseline connection point forecasts having minimal impact on the final connection point forecasts. Therefore, the factors the AER cites as reasons for AEMO's forecasts reflect a more realistic expectation of demand have limited influence on AEMO's final connection point forecasts.

<u>AEMO does not place greater reliance on industry knowledge and judgement</u>

The AER is incorrect in its stated reason for preferring AEMO's methodology because it places a greater reliance on industry knowledge and judgement. The AER has provided no explanation as to how it considers AEMO has

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271 CIE, *Review of Assessment of Forecasts by Darryl Biggar and AER*, December 2015, p. 6.

272 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's demand forecasting methodology*, September 2015, p. 11.

273 CIE, *Review of 2015 AEMO Transmission connection point forecasts and methodology*, December 2015, p. 48.

274 CEPA, *Review of demand forecasting approaches*, December 2015, p. iv and 36.

incorporated industry knowledge and judgement or how use of this information ensures its forecasts reflect a realistic expectation of demand.

We have engaged multiple expert consultants, GHD, CIE and CEPA, to review AEMO's methodology, none of which can identify how AEMO's methodology utilises industry knowledge.

If the AER is referring to AEMO's use of an off-the-point approach then CIE explains:[275]

> *In my view, there is no industry knowledge or judgement implied in choosing to forecast off-the-point, as against forecasting off-the-line. This decision mainly reflects whether the underlying model used for demand is robust, and hence the weight placed on this model versus the latest year of actual demand.*

We have far more industry knowledge and experience than AEMO. AEMO only commenced its connection point forecasts in 2014 and has incorporated no knowledge of our local network characteristics and local demand requirements in its forecasts. AEMO's forecasting methodology uses time as the only driver of its baseline connection point forecasts. It therefore takes no local knowledge or factors into account.

Conversely, we have been preparing demand forecasts for our network for 21 years. We have a wealth of local knowledge and experience regarding our network characteristics and demand requirements. Our forecasting methodology also places greater emphasis on industry knowledge. Our bottom up forecasts, undertaken at the zone substation level, take into account:

- known connections based on connections applications and local planner enquiries;
- additions and reductions in known block load changes, for example supermarkets, residential apartment blocks, department stores and manufacturing plants;
- assessments of the diversification of load requirements and impacts on zone substation capacity; and
- the extensive knowledge and experience of our engineering and planning experts.

We therefore consider the AER has no basis to reach the conclusion that AEMO's forecasts are preferable on the basis that it has greater reliance on industry knowledge and judgement.

AEMO's forecasts do not meet the AER's best practice demand forecasting principles

The AER's preliminary determination substituted our demand forecasts for AEMO's forecasts without assessing AEMO's forecasting approach against its own best practice demand forecasting principles, set out in the explanatory statement to the Expenditure Forecast Assessment Guideline.[276]

CEPA assessed both AEMO's and our forecasting methodologies against the AER's best practice demand forecasting principles. As shown in the table below, CEPA found our approach performed either better, or at least as well as, AEMO's approach against for all the principles. Importantly CEPA considered that:[277]

> *Given the context that the approaches are being used for – the achievement of the NEO and NER – we consider that greater weight should be placed on the 'Accuracy, unbiasedness and testing', 'Incorporation of key drivers', 'weather normalisation' and 'Spatial (bottom-up) forecasts validated by independent system level (top-down) forecasts' principles. Meeting these principles should result in more robust forecasts for estimating the future capex requirements of the Businesses.*

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[275] CIE, *Review of Assessment of Forecasts by Darryl Biggar and AER*, December 2015, p. 9.

[276] CP PUBLIC ATT 9.4 - AER, *Expenditure forecast assessment guideline, Explanatory statement*, pp. 262-267.

[277] CEPA, *Review of demand forecasting approaches*, December 2015, p. 22.

Table 5.4 CEPA assessment against AER best practice demand forecasting principles

Principles	The AER's (AEMO's)	The Businesses'
Accuracy, unbiasedness and testing	🟡	🟢
Transparency	🟡	🟢
Repeatability	🟡	🟡
Incorporation of key drivers	🟡	🟢
Weather normalisation	🟡	🟢
Use of most recent input information and regular review of approaches	🟢	🟢
Spatial (bottom-up) forecasts validated by independent system level (top-down) forecasts	🔴	🟢
Pre/ post-modelling adjustments	🟡	🟡

Source: CEPA, *Review of demand forecasting approaches*, December 2015, pp. ii-iii.
Note: Green = Highest/excellent score, Yellow = Medium/satisfactory score , Red = Low/unsatisfactory score.

CIE, Oakley Greenwood and GHD also reviewed AEMO's forecasting approaches and found it to be lacking in a number of aspects. Key areas of concern with AEMO's forecasting methodology are discussed in detail in the following sections, including:

- AEMO's connection point forecasts fail to incorporate key drivers of demand at the connection point level and therefore do not allow the responsiveness of demand to key drivers to differ spatially;
- AEMO's reconciliation process under-utilises information at the connection point level and results in a simple apportionment of state-wide forecast growth across connection points;
- AEMO's forecasts are insufficiently weather normalised and therefore result in unrealistically low starting point for the forecasts, leading to lower demand across the forecast period;
- AEMO's forecasts are not accurate and unbiased; and
- AEMO's forecast methodology is not transparent.

As a result of these factors, particularly the failure to include drivers of demand at the connection point level and the reconciliation process, AEMO's final connection point forecasts do not reflect a realistic expectation of demand at the connection point level. AEMO's connection point forecasts are therefore not appropriate for assessing local network constraints or our capital and operating expenditure requirements.

Failure to apply accurate forecasts of maximum demand will result in expenditure allowances less than those required to meet the capital and operating expenditure objectives and reasonably reflect the capital and operating expenditure criteria, in particular to meet and manage the demand for standard control services.

<u>Incorporation of key drivers</u>

AEMO's connection point demand forecasts do not take account of economic demand drivers at the connection point level. AEMO's baseline connection point forecasts are based solely on the historical relationship between demand and time. Economic demand drivers are only incorporated in to the final connection point forecasts through the process of reconciling the growth rate in the connection point forecasts to match the growth rate in the state-wide forecasts.

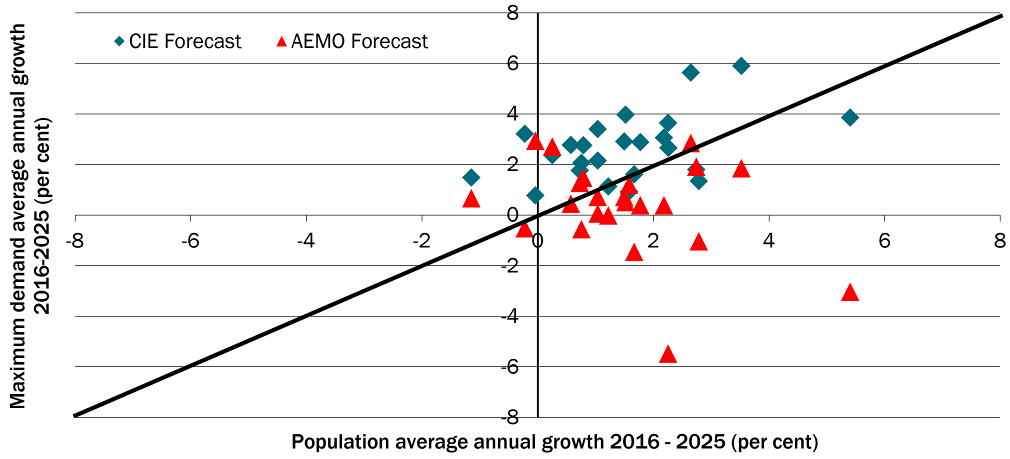
However this indirect approach of incorporating drivers into the connection point forecasts does not allow for the responsiveness of demand to demand drivers to differ spatially given differing customer types and load characteristics. This is unrealistic because connection points service varying proportions of industrial, commercial and residential customers and the different demand requirements of these customer types causes them to respond differently to economic and weather circumstances.

CIE states:[278]

> *Accurate spatial forecasts are important for capital augmentation planning to ensure capital expenditure is deployed where demand is expected to place the greatest pressure on existing infrastructure. If AEMO's forecasts at the connection point level are not linked to demand drivers such as population growth then it is difficult to see how these can be used to inform the understanding of capital augmentation requirements.*

As shown in the figure below, AEMO's connection point forecasts have no relationship with local population growth rates. It is therefore unclear how these forecasts could be used to determine our augmentation expenditure requirements.

Figure 5.4 Forecast connection point maximum demand growth and forecast local population growth



Source: CIE, *Review of 2015 AEMO Transmission connection point forecasts and methodology*, December 2015, p. 9.

AEMO's approach of incorporating drivers of demand into the connection point forecasts through the reconciliation process does not ensure the forecasts provide a realistic expectation of demand because:

- the allocation of growth across connection points is essentially random because AEMO does not incorporate any drivers of demand into the allocation of demand across connection points;[279] and
- it effectively results in all connection point in Victoria receiving the same proportional growth adjustment.[280]

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278 CIE, *Review of 2015 AEMO Transmission connection point forecasts and methodology*, December 2015, p. 27.

279 CIE, *Review of 2015 AEMO Transmission connection point forecasts and methodology*, December 2015, p. 27.

280 CEPA, *Review of demand forecasting approaches*, December 2015, p. 29.

AEMO's crude allocation of state-wide demand growth to connection points will result in a misallocation of the contribution of economic demand drivers across connection points. Further, the reconciliation process is not applied in the 2016 year and therefore no drivers of demand are incorporated directly or indirectly into AEMO's 2016 connection point demand forecasts.

Conversely, our top-down methodology does take account of local demand characteristics because the relationship between demand and demand drivers is estimated at the connection point level. Our approach allows demand growth to vary by local population forecasts and local responsiveness to economic and weather conditions. CEPA found that CIE uses a significantly higher number of drivers than AEMO for connection point forecasting and the analysis is therefore less likely to suffer from omitted variable bias.[281]

Our forecasting approach therefore better meets the AER's best practice demand forecasting principles of incorporating key demand drivers and provides a more realistic expectation of demand at the connection point level. As a consequence, our forecasts provide a more realistic basis for assessing our capital augmentation and expenditure requirements than AEMO's.

<u>Spatial (bottom-up) forecasts validated by independent system level (top down) forecasts</u>

AEMO's process of reconciling the connection point and state-wide forecasts is a major concern, particularly given the large impact the reconciliation process has on AEMO's final connection point forecasts.

The intended purpose of reconciling bottom-up and top-down forecasts is to utilise valuable information from both forecast sources to arrive at a more accurate and robust forecast. ACIL Allen note that:[282]

> *Bottom-up and top-down forecasts have their own strengths and weakness. The purpose of reconciliation is to capture the 'best of both worlds' and develop forecasts that have the strengths of both techniques.*

CIE and Oakley Greenwood explain that standard forecasting practice is to use the reconciliation process to understand why there are significant gaps between the bottom-up and top-down forecasts and to use this information to modify and improve both the top-down and bottom-up forecasting models.[283] Similarly GHD states there is sizeable literature on combining forecasts in order to take the most of advantage of the both the bottom-up and top-down forecasts.[284]

As noted by CEPA, AEMO's reconciliation approach is more akin to a capping exercise rather than a reconciliation exercise. CEPA explain that AEMO apply a mechanistic adjustment without investigating the reasons for the inconsistencies between the bottom-up and top-down forecasts and disregarding the possibility of different growth rates across different distribution networks in Victoria. Overall, CEPA find AEMO's reconciliation and validation process unsatisfactory.[285]

GHD state that the divergence between AEMO's baseline connection point forecasts and the state-wide forecasts is a material source of concern and the large gap between the forecasts implies that one or the other of these must be inaccurate. GHD consider that the strength of the bottom-up forecasts should be the wealth of detail from which they are built up however because AEMO's connection point forecasts are scaled to match the state-wide forecasts the bottom-up information is not effectively utilised.[286] GHD also states:[287]

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[281] CEPA, *Review of demand forecasting approaches*, December 2015, p. 26.

[282] CP PUBLIC ATT 8.6 - ACIL Allen, *Demand forecasts - reconciliation review*, 27 January 2015, p. ii.

[283] CIE, *Review of AEMO 2015 Transmission connection point forecasts and methodology*, December 2015, pp. 26-27. CP PUBLIC ATT 8.9 - CIE and Oakley Greenwood, *Review of AEMO Transmission Connection Point Forecasts*, January 2015, p. 15.

[284] CP PUBLIC ATT 8.7 - GHD, *Review of AEMO Demand Forecasting Methodology*, January 2015, p.23.

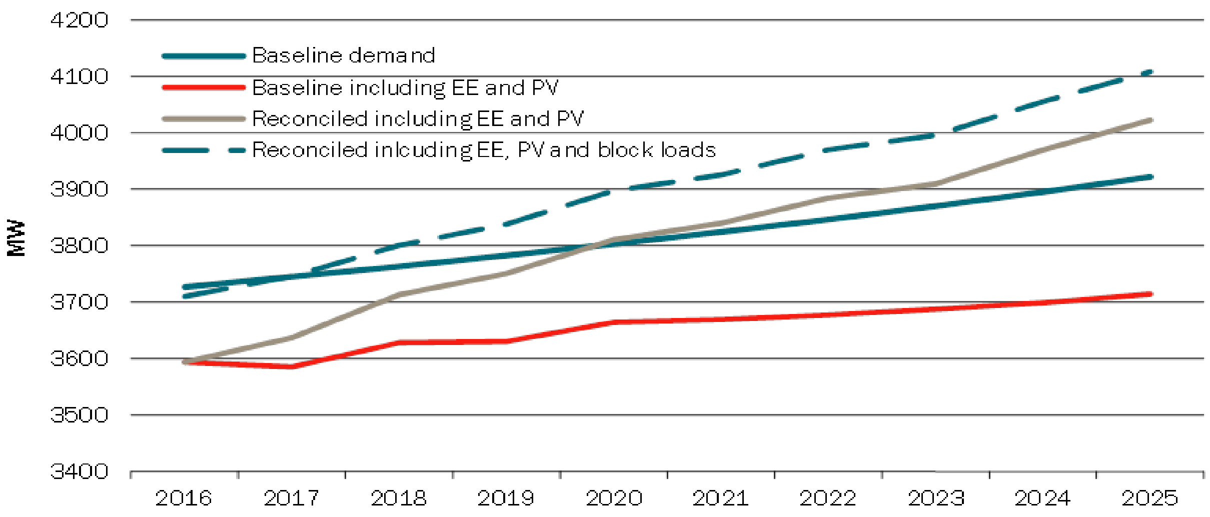
[285] CEPA, *Review of demand forecasting approaches*, December 2015, pp. 11 and 29-30.

[286] CP PUBLIC ATT 8.7 - GHD, *Review of AEMO Demand Forecasting Methodology*, January 2015, pp.19 and 23.

- the impact of reconciliation increases over the forecast period and in many cases changes a declining demand trend into a growing trend; and
- inconsistency between state-wide and connection point forecasts is only one indication of the range of possible forecast errors.

CIE demonstrates the significant adjustments to the baseline connection point forecasts that result from the 2015 reconciliation process, as shown in the figure below, and explain that as a consequence of the significant adjustments resulting from the reconciliation process, the baseline connection point forecasts have a minor impact on the final connection point forecasts.[288] Notably, while the 2015 reconciliation process had the effect of increasing the connection point forecasts, the 2014 reconciliation process had the reverse effect by reducing connection point forecasts and of a more significant magnitude.[289]

Figure 5.5 Impact of AEMO 2015 reconciliation process



Source: CIE, *Review of AEMO Transmission Connection Point Forecasts*, December 2015, p. 25.

It is clear that, due to the reconciliation process, AEMO's connection point forecasting approach:

- effectively results in an simple allocation of the state-wide forecasts to different connection points in Victoria;
- does not follow the best practice approach for combining the different strengths of bottom-up and top-down forecasts; and
- results in forecasts which do not reflect a realistic expectation of demand requirements at the connection point level, and therefore the forecast cannot inform the efficient level of capital expenditure for augmentation.

Importantly, unlike AEMO's forecasting approach, our forecasting methodology effectively utilises the value of information sourced from both our bottom-up and top-down forecasts. Our bottom-up forecasts take account of

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287 GHD, *AEMO Demand forecast review (2015 update)*, December 2015, p. 5 and 22.

288 CIE, *Review of 2015 AEMO Transmission connection point forecasts and methodology*, December 2015, p. 26.

289 CP PUBLIC ATT 8.9 - CIE and Oakley Greenwood, *Review of AEMO Transmission Connection Point Forecasts*, January 2015, pp. 4-5 and 14-15.

local expert knowledge and local demand characteristics at the zone substation level and our top-down forecasts utilise information on the responsiveness of demand at the connection point level to key economic demand drivers. Our methodology therefore combines the strengths of a top-down econometric forecasting approach with the strengths of a bottom-up forecasting approach.

Further, CIE notes that our bottom-up and top-down forecasts were relatively close before reconciliation, providing additional support for the accuracy and robustness of the forecasts.[290] Our reconciliation process ensures that our forecasts reflect a realistic expectation of demand at the connection point level and therefore provide a strong basis for assessing the location of network constraints and our efficient capital expenditure requirements to meet demand for standard control services over the 2016–2020 regulatory control period.

Weather normalisation

AEMO's weather normalisation process at the connection point level does not:

- take into account the impact on maximum demand of the time of day that peak temperatures occur;
- take into account the compounding impact of temperatures over multiple days; and
- allow the relationship between demand and temperature to vary in a non-linear way.

AEMO's assumptions are unrealistic because:

- demand is sensitive to the time of day that peak temperatures occur. For example, if peak temperatures occur during the middle of the day when residential consumption is low, the impact on demand will be low compared with a situation where peak temperatures occur after business hours when residential consumption peaks;
- demand is sensitive to high temperatures occurring over multiple days. For example, if peak temperatures occur over multiple days it becomes more difficult to cool buildings; and
- as discussed in the Biggar report, the relationship between peak demand and temperature is not necessarily a straight line and there is potential for saturation such that once temperatures reach a very high point demand does not continue to increase at the same rate as at moderate temperatures.[291]

CIE states:[292]

> *In my view the weather normalisation undertaken by AEMO at the connection point level is not best practice because it does not account for weather over multiple days, non-linear relationships between temperature and electricity demand and temperature across the day relevant for each half hour. This means that there is likely to be a substantial weather normalisation error in the AEMO approach using off-the-point forecasts.*

Conversely, our weather normalisation process at the connection point level accounts for all of these factors, the time of day that temperatures peak, the impact of temperature over consecutive days and the relationship between demand and temperature varies in a non-linear way. Importantly, Biggar's report is factually incorrect in its statements that AusNet Services is the only distributor to allow for the possibility of temperature sensitivity to reduce at very high temperatures.[293] CIE's methodology allows temperature sensitivity of demand to vary in a non-linear way by including squared and cubic terms for current temperature and temperature splines for

290 CIE, *Review of 2015 AEMO Transmission connection point forecasts and methodology*, December 2015, p. 27.

291 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's demand forecasting methodology*, September 2015, pp. 5-6.

292 CIE, *Review of Assessment of Forecasts by Darryl Biggar and the AER*, December 2015, p. 9.

293 CIE, *Review of Assessment of Forecasts by Darryl Biggar and the AER*, December 2015, p. 6.

maximum and minimum temperature. These allow for an S-curve in the relationship between demand and temperature.[294]

Additionally, CIE allows for the temperature sensitivity of demand to vary over time. As noted in the Biggar report, CIE's approach is a valuable extension of the Hyndman and Fan model used by AEMO.[295] The AER's preliminary determination is factually incorrect in its statement that CIE's modelling enforces a single relationship between maximum demand and weather across the ten year period.[296] As noted, CIE explicitly allows for temperature sensitivity of demand to vary over time.

CEPA's assessment of both AEMO's and our approach to weather normalisation finds our approach to be preferable to AEMO's, in particular noting that:[297]

- our approach is best practice as it allows for both time and weather variables to be controlled simultaneously;
- our approach includes higher order temperature variables to capture the non-linear relationship between demand and temperature, while AEMO's does not; and
- our approach makes good use of the dataset by including weekends and holidays and controlling for these with dummy variables, while AEMO have excluded these days.

Inaccurate weather normalisation has two key consequences for AEMO's connection point forecasts:

- the starting point for the forecasts is understated, leading to lower levels of demand across the 2016–2020 regulatory control period; and
- connection points will be impacted differently by the weather normalisation process and this will lead to a mis-allocation of demand across connection points when AEMO reconciles the connection point forecasts to match the state-wide forecasts.

Consequently, AEMO's connection point forecasts do not provide a realistic expectation of demand at the connection point level and therefore do not provide a reasonable basis for assessing the location of network constraints and our capital expenditure requirements for augmentation of the network.

<u>Accuracy and unbiased</u>

AEMO has only been preparing the connection point forecasts since 2014. During that time AEMO's forecasts have been volatile. The level of volatility in the forecasts and the significant gap between the state-wide and connection point forecasts is indicative of forecasting inaccuracy, instability and unreliability.

As shown in the figure below, AEMO has made significant adjustments to its state-wide forecasts each year. Further, AEMO has acknowledged that there are outstanding issues with its forecasting methodology that it will seek to address in its 2016 forecasts.[298] The accuracy of the state-wide forecasts are important because, as discussed above, the reconciliation process effectively results in the baseline connection point forecasts being overridden with the state-wide forecasts.

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294 CIE, *Review of Assessment of Forecasts by Darryl Biggar and the AER*, December 2015, p. 6.

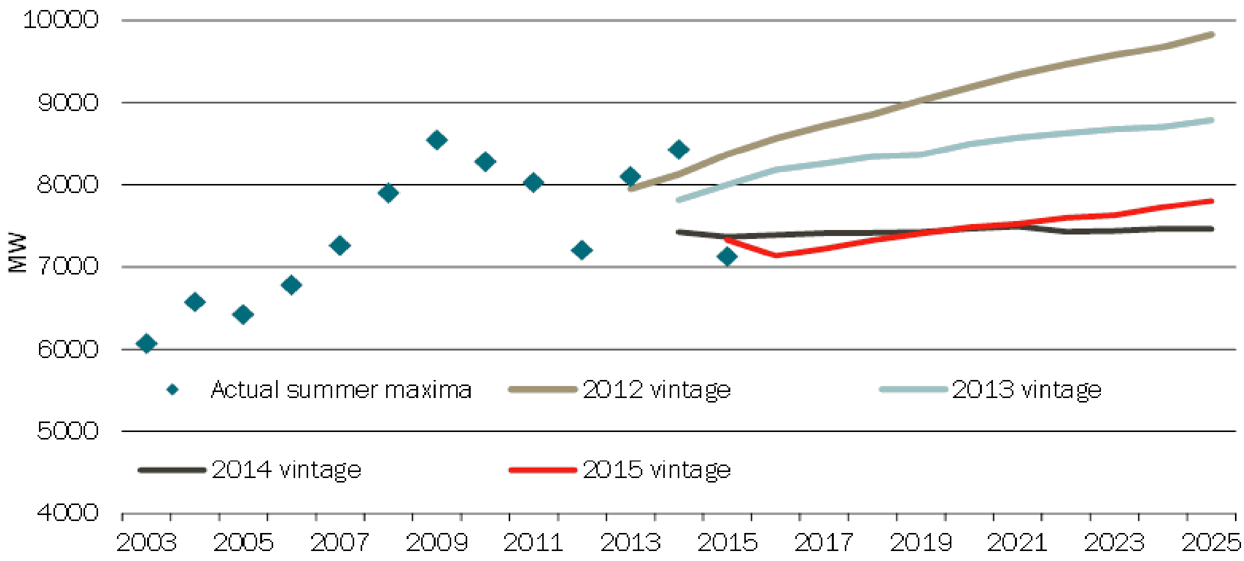
295 Biggar, *2015 Victorian Electricity Distribution Pricing review: An Assessment of the Vic DNSP's demand forecasting methodology*, September 2015, p. 26.

296 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-120.

297 CEPA, *Review of demand forecasting approaches*, December 2015, pp. 27-28.

298 AEMO, *National Electricity Forecasting Report (NEFR) September Feedback Workshops*, October 2015.

Figure 5.6 AEMO National Electricity Forecasting Report, Victoria state-wide forecasts



Source: CIE, *Review of 2015 AEMO Transmission connection point forecasts and methodology*, December 2015, p. 33.

CIE tested the accuracy of AEMO's state-wide model by comparing actual maximum demand outcomes against model predictions over the period 2003 to 2015. CIE found the model was likely over-estimating maximum demand in the first half of the sample period and under-estimating maximum demand in the second half of the sample period.[299]

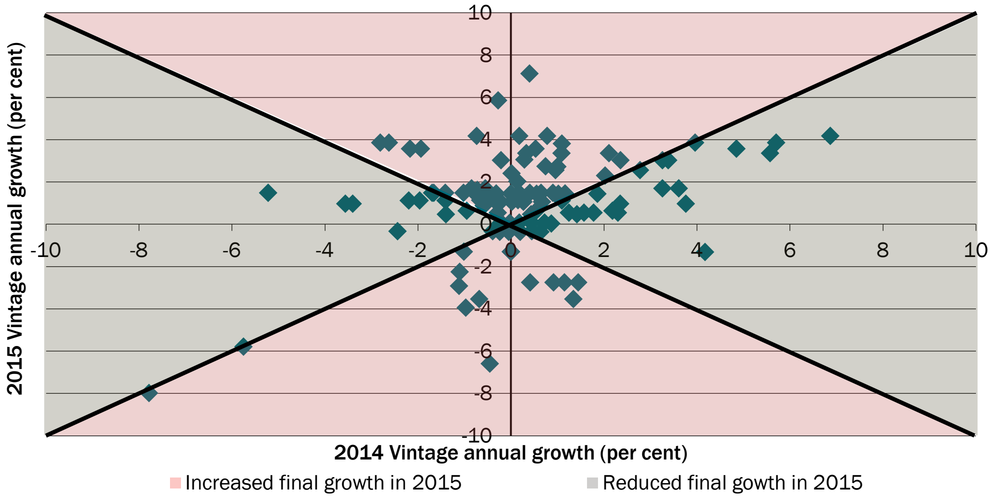
Further, CIE notes that AEMO's state-wide forecasts assume that aggregate demand growth for residential and commercial customers exceeds peak demand growth during the forecast period. This trend is out of step with historical trends over the past ten years where aggregate demand has grown at a slower rate than peak demand. AEMO provide no explanation for reversing the relationship between aggregate and maximum demand.[300]

Similarly at the connection point level, AEMO's forecasts are unstable across years. As shown in the figure below, the change in forecast demand annual growth rate between the 2014 and 2015 forecasts is essentially random with large changes, in both positive and negative directions, for most connection points. This provides evidence that the forecasts are neither accurate nor reliable.

[299] CIE, *Review of 2015 AEMO Transmission connection point forecasts and methodology*, December 2015, p. 35.

[300] CIE, *Review of 2015 AEMO Transmission connection point forecasts and methodology*, December 2015, p. 32.

Figure 5.7 Comparison of AEMO's final transmission connection point forecasts in 2014 and 2015



Source: CIE, *Review of 2015 AEMO Transmission connection point forecasts and methodology*, December 2015, p. 16.

Further, CEPA found our forecasting approach to be preferable to AEMO's in respect to accuracy and unbiasedness. CEPA note that:[301]

- CIE undertake within sample model testing and show the model predicts well within sample, conversely it is not possible to assess the accuracy of AEMO's connection point forecasts;
- CIE relies on large sample sizes with sufficient degrees of freedom and statistically robust models;
- CIE uses a general to specific modelling approach which CEPA considers to be best practice;
- CIE checks the economic interpretation of the elasticities is intuitive;
- AEMO's regressions may be subject to omitted variable bias; and
- it would be preferable for AEMO to use industry knowledge to assess if industrial loads should receive lower or zero growth or be omitted from the weather normalisations. However, it is unclear if industry knowledge was used.

AEMO's connection point forecasts therefore have not proven to be sufficiently accurate or unbiased for the AER to conclude that the forecasts provide a more realistic expectation of demand than our forecasts.

Importantly, we have been forecasting demand for network planning purposes for 21 years. We have found our internal forecasting approach to be sufficiently accurate and reliable for network planning purposes. We have incorporated both econometric based analysis, which links demand forecasts to key demand drivers, and the value of local knowledge through our bottom up spatial forecasts. Our demand forecasts are a key factor in our assessment of the location of network constraints and the level of augmentation and capital expenditure required to relieve these constraints. Our forecasts therefore provide a realistic expectation of demand appropriate for assessing our capital and operating expenditure requirements.

[301] CEPA, *Review of demand forecasting approaches*, December 2015, pp. 23-24.

Transparency

The information available on AEMO's forecasting methodology is not sufficient for stakeholders to fully understand the modelling approach and therefore assess how the outcomes were derived. Throughout the regulatory review process we have raised numerous questions with AEMO and the AER in order to further our understanding of AEMO's forecasting model. However, in most cases the requested information has not been provided. AEMO's response has been to deny our information requests, citing resource constraints.[302]

This limits our, and our advisers, ability to fully assess the reasonableness of AEMO's assumptions, thus denying us due process. We understand that the AER has also not been provided access to additional information on AEMO's methodology, therefore the AER does not have sufficient information to fully assess the reasonableness of AEMO's forecasts.

Importantly, AEMO have not provided:

- the Monash model which is the basis for the state-wide forecasts used to reconcile the connection point forecasts. This means we cannot test the robustness of the model or fully understand the model workings or assumptions which are not explained in AEMO's high level documentation;
- the trend line equations applied to each connection point to forecast the growth from historical data. This information is important for understanding the basis upon which AEMO developed its baseline connection point forecasts and how the approach differs from our forecasting method;
- an explanation of why no reconciliation was undertaken in 2016 but was undertaken for 2017–2020. This is important for understanding why AEMO considers the state-wide growth is not relevant for the connection point forecasts in 2016 but is in 2017–2020;
- an explanation of why AEMO's block load adjustments are inconsistent with the information we provided to AEMO on block load adjustments in our network;
- AEMO's historical weather corrected data by connection point. This information is important for understanding the extent to which differences in the approach to weather normalisation are contributing to the differences between AEMO's forecasts and our forecasts. Differences in weather normalisation would lead to differences in the starting point for the forecasting analysis and potentially differences in the underlying trends relied on to develop the forecasts; and
- a number of input assumptions are based on unpublished reports which limits the ability for stakeholders, including the AER, to validate the reasonableness of the input assumptions. For example the load factors used to assess the impact of energy efficiency on demand.

In response to stakeholder feedback, AEMO has stated it will seek to provide more information and data to support stakeholder understanding and analysis with its 2016 forecasts.[303] This is an implicit acknowledgement by AEMO that it could be more transparent in its approach.

Conversely, we provided all of our models prepared by CIE and the necessary statistical programming code to the AER to ensure our forecasting methodology is transparent. CEPA's assessment of AEMO's and our forecasting approaches also found our forecasts to be more transparent than AEMO's.[304]

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[302] AEMO email to CitiPower and Powercor regarding demand forecasting dated 17 November 2015 states that 'at this stage AEMO is unable to respond to your request as outlined below. We are currently in the process of working on a number of high profile deliverables and do not currently have the required free resources to allocate to your request.'

[303] AEMO, *National Electricity Forecasting Report (NEFR) September Feedback Workshops*, October 2015.

[304] CEPA, *Review of demand forecasting approaches*, December 2015, pp. 24-25.

The adoption by the AER of AEMO's connection point forecasts in its preliminary determination, in circumstances where we have been denied the opportunity to properly scrutinise AEMO's forecasting methodology, is a denial of procedural fairness in breach of the AER's obligations at common law and under section 16(1)(b) of the Law, and if perpetuated in the final decision will, likewise, involve a breach of those obligations in respect of the final determination.

Further, in circumstances where the information available to the AER on AEMO's forecasting methodology is likewise limited and the AER is unable to properly understand and assess the methodology, there is no proper basis for the AER to reach conclusion that AEMO's forecasts reflect a more realistic expectation of forecast demand than our forecasts. For the AER to rely on these forecasts in the final determination would therefore be incorrect and unreasonable.

5.2.6 Our revised regulatory proposal

We maintain that our forecasting approach is robust and reliable and provides the best estimate of demand for standard control services in the 2016–2020 regulatory control period. Our updated demand forecasts, derived using this approach, reasonably reflect a realistic expectation of demand for our standard control services over that period.

For our revised regulatory proposal, we therefore apply our updated 2015 demand forecasts for the purposes of forecasting our operating and capital expenditure requirements and consider that the AER should accept our demand forecasts in accordance with the requirements of clauses 6.5.6(c), 6.5.7 (c), 6.12.1(3)(ii) and 6.12.1(4)(ii) of the Rules.

Our updated demand forecasts are provided in the table below.

Table 5.5 Summated connection point non-coincident maximum demand, MW

	2016	2017	2018	2019	2020
10% POE, MW	1,525	1,569	1,648	1,688	1,723
50% POE, MW	1,423	1,463	1,535	1,568	1,599
50% POE, growth rate (%)	2.09	2.76	4.94	2.14	1.99

Source: CitiPower

5.3 Customer forecasts

5.3.1 Initial regulatory proposal

Our customer number forecasts are used to develop our operating expenditure forecasts for the 2016–2020 regulatory control period.

For our regulatory proposal we engaged the CIE to develop our customer number forecasts for the 2016–2020 regulatory control period. CIE forecast the growth rate in customer numbers for residential, commercial and industrial customers as follows:

- residential customers – based on the forecast growth in dwelling numbers by Local Government Area (**LGA**) produced by the Victorian Government Department of Transport, Planning and Local Infrastructure. CIE mapped the relevant LGAs to our network area;
- commercial customers – based on a time trend from the most recent data point (2013); and
- industrial customers – assumed zero growth from the most recent data point (2013).

Table 5.6 Customer number growth rates (per cent)

	2016	2017	2018	2019	2020
Customer number rates	2.0	1.6	1.6	1.6	1.6

Source: CP PUBLIC ATT 8.10 - CIE, Tariff volume forecasts, February 2015, p. 7.

5.3.2 AER's preliminary determination

The AER accepted our forecasts of non-residential and unmetered customers.

The AER rejected our forecasts of residential customers because it:

- noted our forecasts exceed the historical growth rate;
- considered that historical average growth rate is appropriate if forecast population growth in the network area reflects historic growth rates; and
- noted that dwelling statics are only reported every five years.

The AER substituted our residential customer number forecasts for the historical average growth rate.

5.3.3 Our revised regulatory proposal

We accept the AER's preliminary determination to accept our proposed customer number forecasts for non-residential and unmetered customers.

While we do not agree with the AER's reasons for rejecting our residential customer number forecasts, we accept the AER's preliminary determination to forecast the growth in residential customers based on our historic growth rate.

For our revised regulatory proposal we therefore accept the customer number forecasts applied in the AER's preliminary determination. Our customer number forecasts for our revised regulatory proposal are set out in the table below.

Table 5.7 Customer number growth rates (per cent)

	2016	2017	2018	2019	2020
Customer number rates	1.4	1.4	1.4	1.4	1.4

Source: AER, *Preliminary decision, CitiPower distribution determination 2016–20*, *Opex model,* October 2015, tab 'Input|Rate of change', row 73.

Operating expenditure 6

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6 Operating expenditure

In this chapter of our revised regulatory proposal we respond to chapter 7 of the Australian Energy Regulator's (**AER's**) preliminary determination in respect of operating expenditure. We also set out our revised operating expenditure forecast for the 2016–2020 regulatory control period.

Adjustments to base year operating expenditure

We have prepared our revised regulatory proposal to be consistent with the AER's preliminary determination on adjustments to base year operating expenditure, except with respect to the following:

- we have retained our proposed adjustment to base year operating expenditure due to the reclassification of expenditure on particular IT systems from metering services to standard control services;
- we have not included the AER's proposed adjustment to remove operating expenditure for losses associated with the scrapping of assets as this adjustment was incorrect because our base year operating expenditure does not include losses associated with the scrapping of assets; and
- we have included a revised forecast of guaranteed service level (**GSL**) payments over the 2016–2020 regulatory control period because the Essential Services Commission of Victoria (**ESCV**) has recently published a final decision which sets out changes to the GSL scheme for that period and, accordingly, impacts on forecast GSL payments.

Rate of change

Our response to the AER's preliminary determination with respect to real price growth is set out in chapter 4 of our revised regulatory proposal. However, this chapter of our revised regulatory proposal includes our response to the AER's preliminary determination with respect to output growth and productivity growth.

We have prepared our revised regulatory proposal to be consistent with the AER's preliminary determination with respect to output growth escalation, except that we have substituted our revised demand forecasts for those used by the AER in its preliminary determination.

We have prepared our revised regulatory proposal to be consistent with the AER's preliminary determination to apply a zero per cent productivity growth forecast (which is also consistent with our regulatory proposal).

Step changes

We have prepared our revised regulatory proposal to be consistent with the AER's preliminary determination with respect to operating expenditure step changes, except that we dispute the AER's decision to reject our proposed step changes for monitoring IT security, mobile devices and decommissioning zone substations. [redacted]

The AER must accept a proposed step change where it is necessary for our forecast operating expenditure to satisfy the operating expenditure criteria in clause 6.5.6(c) of the National Electricity Rules (**Rules**). Nonetheless, the AER denied each of our proposed step changes that are not the result of new or changed regulatory obligations primarily on the basis that our base year expenditure together with the rate of change is sufficient for our forecast operating expenditure to satisfy the operating expenditure criteria in clause 6.5.6(c) of the Rules.

It is not the case that our base year operating expenditure can fund large operating costs that we need to incur in 2016–2020 regulatory control period in order to maintain the quality, reliability and security of supply of standard control services and the safety, reliability and security of the distribution system through the supply of standard control services. This is particularly so, in circumstances where, as the AER recognises in its preliminary determination, we are one of the most efficient service providers in the National Electricity Market (**NEM**). Accordingly, consistent with the Rules requirements, we should be allowed step changes for operating expenditure that is necessary for our total forecast operating expenditure to satisfy the operating expenditure criteria, regardless of whether or not the cause of the increase in operating costs is a new or changed regulatory obligation.

Our proposed operating expenditure step change for monitoring IT security is necessary to manage the risk of security breaches to our IT systems and maintain the safety, reliability and security of our distribution system through the supply of standard control services (clause 6.5.6(a)(3) and (4) of the Rules). Contrary to the AER's preliminary determination, the costs of monitoring our IT security systems on a 24 hour basis cannot be funded through our base year operating expenditure.

Our proposed operating expenditure step change for mobile devices represents an efficient substitution of capital expenditure and operating expenditure. Contrary to the AER's preliminary determination, our proposal to move to an operating expenditure only model for mobile devices is efficient, and further, allowing the step change would not overcompensate us for the prudent and efficient cost of leasing new mobile devices.

[redacted]

Our proposed operating expenditure step change for decommissioning five zone substations is necessary in order to maintain compliance with our regulatory obligations under the *Electricity Safety Act 1998* (Vic) and the *Environment Protection Act 1970* (Vic) (clause 6.5.6(a)(2) of the Rules). It is also necessary to maintain the safety, reliability and security of our distribution system through the supply of standard control services (clause 6.5.6(a)(3) and (4) of the Rules). Since the costs associated with projects to decommission and remediate sites are not included in our base operating expenditure, it is necessary for us to be allowed this step change for our forecast operating expenditure to satisfy the operating expenditure criteria.

In addition, in our revised regulatory proposal we propose additional step changes in respect of:

- the introduction of cost-reflective tariffs through changes to the Rules;
- regulatory information notice (**RIN**) compliance; and
- the Victorian Government's decision that chapter 5A of the Rules will apply to Victorian distributors.

6.1 Rule requirements

6.1.1 Constituent decisions on operating expenditure

The constituent decisions on which our distribution determination is predicated relevantly include:

- a decision on our annual revenue requirement for each regulatory year of the regulatory control period to which the determination relates (clause 6.12.1(2) of the Rules); and
- a decision in which the AER either accepts our total operating expenditure forecast for that regulatory control period or does not accept that forecast, in which case the AER must determine an estimate of our required operating expenditure for that period (clause 6.12.1(4)).

6.1.2 The operating expenditure criteria, operating expenditure objectives and operating expenditure factors

The AER is required to accept our forecast of required operating expenditure included in our building block proposal where it is satisfied that the total of the forecast operating expenditure for the regulatory control period reasonably reflects the following criteria (operating expenditure criteria) in clause 6.5.6(c) of the Rules:

- the efficient costs of achieving the operating expenditure objectives specified in clause 6.5.6(a) of the Rules (operating expenditure objectives);
- the costs that a prudent operator in the circumstances of the relevant distribution business would require to achieve the operating expenditure objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

If the AER is not so satisfied and, accordingly, does not accept our forecast of required operating expenditure, the AER must estimate our required operating expenditure that it is satisfied reasonably reflects the operating expenditure criteria taking into account the matters specified in clause 6.5.6(e) of the Rules (operating expenditure factors) (clauses 6.5.6(d) and 6.12.1(4)(ii) of the Rules).

The operating expenditure objectives in clause 6.5.6(a) of the Rules are to:

5. meet or manage the expected demand for standard control services over that period;
6. comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
7. to the extent that there is no applicable regulatory obligation or requirement in relation to:
   - the quality, reliability or security of supply of standard control services; or
   - the reliability or security of the distribution system through the supply of standard control services,

   to the relevant extent:
   - maintain the quality, reliability and security of supply of standard control services; and
   - maintain the reliability and security of the distribution system through the supply of standard control services; and
8. maintain the safety of the distribution system through the supply of standard control services.

In deciding whether or not it is satisfied that the forecast operating expenditure for the regulatory control period reasonably reflects the operating expenditure criteria, the AER must have regard to the operating expenditure factors specified in clause 6.5.6(e) of the Rules, being:

- the most recent annual benchmarking report that has been published under clause 6.27 and the benchmark operating expenditure that would be incurred by an efficient distributor over the relevant regulatory control period;
- the actual and expected operating expenditure of the distributor during any preceding regulatory control periods;
- the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by the distributor in the course of its engagement with electricity consumers;
- the relative prices of operating and capital inputs;

- the substitution possibilities between operating and capital expenditure;
- whether the operating expenditure forecast is consistent with any incentive scheme(s) that apply to the distributor under clauses 6.5.8 or 6.6.2 to 6.6.4;
- the extent to which the operating expenditure forecast is referrable to arrangements with a person other than the distributor that, in the opinion of the AER, do not reflect arm's length terms;
- whether the operating expenditure forecast includes an amount relating to a project that should more appropriately be included as a contingent project under clause 6.6A.1(b);
- the extent to which the distributor has considered, and made provision for, efficient and prudent non-network alternatives; and
- any other factor the AER considers relevant and which the AER has notified the distributor in writing prior to the submission of its revised regulatory proposal in relation to the revoked determination is an operating expenditure factor.

In its preliminary determination, the AER took into account the following two additional operating expenditure factors under the last factor referred to above:[305]

- the AER's benchmarking data sets including, but not necessarily limited to:
  - data contained in any economic benchmarking regulatory information notice (**RIN**), category analysis RIN, reset RIN or annual reporting RIN;
  - any relevant data from international sources; and
  - data sets that support econometric modelling and other assessment techniques consistent with the approach set out in the AER, *Expenditure forecast assessment guideline*, November 2013,

  as updated from time to time; and
- economic benchmarking techniques for assessing benchmark efficient expenditure, including econometric models and multilateral total factor productivity analysis.

6.2 Base year operating expenditure

6.2.1 Initial regulatory proposal

As set out in chapter 10 of our regulatory proposal, we developed our operating expenditure forecast for the 2016–2020 regulatory control period using a 'base-step-trend' approach. This approach is consistent with the AER's preferred approach in its *Expenditure forecast assessment guideline*.[306]

We forecast operating expenditure of $489.6 million ($2015) (excluding debt raising costs and the Demand Management Innovation Allowance (**DMIA**)) for the 2016–2020 regulatory control period.

We developed our operating expenditure forecast for the 2016–2020 regulatory control period as follows:

- we nominated 2014 as the efficient revealed costs base year;
- we adjusted our base year operating expenditure to present the forecast operating expenditure consistent with the approved cost allocation methodology (**CAM**) applicable in the 2016–2020 regulatory control

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305 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-14.

306 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 22.

period.[307] This adjustment was made due to changes in our approach to corporate overheads in our CAM, being to fully expense corporate overheads from 1 January 2016;[308]

- we adjusted our base year operating expenditure to include an efficient forecast for activities for which base year operating expenditure did not reflect operating expenditure going forward (including a review for any non-recurrent costs). This involved removing actual expenditure for the following items from base year operating expenditure and including a forecast of those items in our operating expenditure forecast:[309]
  - regulatory reset costs;
  - GSL payments;
  - defined benefit superannuation contributions;
  - the DMIA; and
  - debt raising costs;
- we adjusted our base year operating expenditure to include an efficient forecast for services reclassified as standard control services. This involved adjustments to include a forecast of the following items:[310]
  - the reclassification of supply abolishment from alternative control services to standard control services;
  - the alignment of the accounting of certain replacement costs (being pole treatment costs, bird covers, fuses and surge diverters) to be consistent with the category analysis RIN; and
  - the reclassification of IT metering operating expenditure from metering services to standard control services;
- we added to the base year operating expenditure the efficient level of forecast step changes for the 2016–2020 regulatory control period; and
- we added to the base year operating expenditure the efficient level of operating expenditure determined by applying a rate of change formula, including the rate of change in real prices, output growth and productivity.

6.2.2 AER's preliminary determination

In its preliminary determination, the AER did not accept our forecast operating expenditure included in our building block proposal on the basis that it was not satisfied that our forecast operating expenditure reasonably reflected the operating expenditure criteria in clause 6.5.6(c) of the Rules. The AER determined an alternative, substitute estimate of our total forecast operating expenditure for the 2016–2020 regulatory control period of $1,155.1 million ($2015) (excluding debt raising costs and the DMIA).[311]

The AER adopted a top down forecasting method to assessing our forecast operating expenditure and developing its alternative estimate. The AER used the following approach to assess our forecast operating expenditure and developing its alternative operating expenditure forecast:[312]

1. the AER started with our operating expenditure in the base year;

[307] CP PUBLIC ATT 9.2 - CitiPower, *Cost Allocation Method*, April 2014, Version 9.

[308] CitiPower, *Regulatory Proposal 2016–20*, April 2015, p. 164.

[309] CitiPower, *Regulatory Proposal 2016–20*, April 2015, pp. 164–165 and appendix F.

[310] CitiPower, *Regulatory Proposal 2016–20*, April 2015, p. 165 and appendix F.

[311] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-8.

[312] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-17.

2. the AER considered whether it was necessary to adjust base operating expenditure;
3. the AER added a rate of change to base operating expenditure;
4. the AER added or subtracted any step changes; and
5. finally, the AER added any additional operating expenditure components which had not been forecast using this approach (for example, debt raising costs).

Consistent with our proposal, the AER relied on our reported operating expenditure in 2014 to forecast operating expenditure. The AER considered this to be a reasonable starting point for determining its operating expenditure forecast since benchmarking indicates that we are operating relatively efficiently when compared to other service providers in the NEM.[313]

In determining its alternative operating expenditure forecast, the AER made the following adjustments to our base year operating expenditure:

- an adjustment due to changes in our corporate overhead capitalisation policy. The AER did not approve our proposed adjustment in its entirety on the basis that our proposed adjustment only reflected our capitalised corporate overheads expenditure in 2014. Rather, the AER determined that the adjustment should reflect an average of our capitalised corporate overheads between 2012 and 2014; [314]
- an adjustment to give effect to the reclassification of supply abolishment from alternative control services to standard control services, consistent with our proposal;[315]
- an adjustment due to the alignment of the accounting of certain replacement costs (being pole treatment costs, bird covers, fuses and surge diverters) to be consistent with the category analysis RIN, consistent with our proposal;[316]
- an adjustment to remove the DMIA, consistent with our proposal;[317]
- adjustments for movements in provisions, consistent with our proposal;[318] and
- an adjustment to remove operating expenditure for losses associated with the scrapping of assets.[319]

In addition, in determining its alternative operating expenditure forecast, the AER:

- adjusted base operating expenditure to remove operating expenditure incurred in 2014 on debt raising costs and include a forecast for debt raising costs over the 2016–2020 regulatory control period;[320] and
- adjusted base operating expenditure to remove operating expenditure incurred in 2014 on GSL payments and include a forecast for GSL payments over the 2016–2020 regulatory control period as the average of GSL payments made by us between 2010 and 2014.[321]

Further, the AER rejected our proposed adjustments to base operating expenditure for:

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313 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-23.
314 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-40 to 7-43.
315 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.
316 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.
317 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.
318 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.
319 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, 7-45.
320 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-26 and 7-45.
321 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-25 and 7-45.

- the reclassification of IT metering operating expenditure from metering services to standard control services;[322]
- defined benefit superannuation contributions (the AER dealt with this adjustment in its discussion of step changes in its preliminary determination);[323] and
- regulatory reset costs (the AER dealt with this adjustment in its discussion of step changes in its preliminary determination).[324]

6.2.3 Our response to the AER's preliminary determination

We have prepared this revised regulatory proposal to be consistent with the AER's preliminary determination on adjustments to base year operating expenditure in respect of the following:

- the AER's adjustment to base year operating expenditure due to changes in our capitalisation policy;[325]
- our proposed adjustment to base year operating expenditure, accepted by the AER, to give effect to the reclassification of supply abolishment from alternative control services to standard control services;[326]
- our proposed adjustment to base year operating expenditure, accepted by the AER, due to the alignment of the accounting of certain replacement costs (being pole treatment costs, bird covers, fuses and surge diverters) to be consistent with the category analysis RIN;[327]
- our proposed adjustment to base year operating expenditure, accepted by the AER, to remove the DMIA;[328]
- our proposed adjustments to base year operating expenditure for movements in provisions, accepted by the AER;[329]
- the AER's adjustment to base operating expenditure to remove operating expenditure incurred in 2014 on debt raising costs and the AER's forecast for debt raising costs over the 2016–2020 regulatory control period;[330]
- the AER's decision not to remove regulatory reset costs from base year operating expenditure;[331] and
- the AER's decision not to adjust base year operating expenditure for our forecast defined benefit superannuation contributions.[332]

We dispute the AER's preliminary determination on adjustments to base year operating expenditure in respect of the following:

- the AER's decision not to adjust base year operating expenditure due to the reclassification of IT metering expenditure from metering services to standard control services;[333] and

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322 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-43 to 7-45.
323 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-79 to 7-82.
324 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-78 to 7-79.
325 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-42 to 7-45.
326 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-47.
327 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.
328 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.
329 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.
330 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-26 and 7-45.
331 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-78 to 7-79.
332 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-79 to 7-82.

- the AER's adjustment to remove operating expenditure for losses associated with the scrapping of assets.[334]

In addition, with respect to the AER's preliminary determination on the adjustment to base operating expenditure for GSL payments:

- we accept the AER's removal of operating expenditure incurred in 2014 on GSL payments;
- however, we reject the AER's forecast for GSL payments over the 2016–2020 regulatory control period. This is because the ESCV has recently published a final decision which sets out changes to the GSL scheme for the 2016–2020 regulatory control period and, accordingly, impacts on forecast GSL payments for that period.[335]

We describe our position on the adjustment for GSL payments in further detail below, in addition to responding to the AER's decisions to reject our proposed adjustment for the reclassification of IT metering operating expenditure, and to make an adjustment for losses associated with the scrapping of assets.

6.2.4 Guaranteed service level payments

Initial regulatory proposal

As set out in our regulatory proposal, we are required to make GSL payments to customers who experience reliability that is worse than specified performance thresholds.[336] These payments may exhibit significant volatility across years based on a range of extraneous factors.

Accordingly, in our regulatory proposal, we made an adjustment to base operating expenditure to remove operating expenditure incurred in 2014 on GSL payments and include a forecast for GSL payments for each year of the 2016–2020 regulatory control period.[337] Our forecast reflected an average of GSL payments over the period 2011–2014 (adjusted for forecast customer growth).

AER's preliminary determination

In its preliminary determination, the AER removed operating expenditure incurred in 2014 on GSL payments from our base operating expenditure and forecast GSL payments as the average of GSL payments made by us between 2010 and 2014.[338] Unlike our proposal, the AER did not adjust its forecast for output growth either in determining the individual forecast for GSL payments or by applying an overall rate of change to base year adjustments and step changes. The AER stated that it adopted the historical averaging approach to maintain consistency with how GSL payments have been forecast for previous regulatory control periods.

Our response to the AER's preliminary determination

We accept the AER's removal of operating expenditure incurred in 2014 on GSL payments from our base operating expenditure, however, we reject the AER's forecast for GSL payments over the 2016–2020 regulatory control period.

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333 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-43 to 7-45.

334 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.

335 ESCV, *Review of the Victorian electricity distributors' GSL payment scheme, final decision,* 23 December 2015.

336 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix F, p. 4.

337 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, p. 165 and appendix F, p. 4.

338 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-25.

On 17 November 2015 the ESCV published a draft decision entitled *Review of the Victorian electricity distributors' guaranteed service level payment scheme* that proposed changes to its GSL scheme for the 2016–2020 regulatory control period.[339] On 23 December 2015, the ESCV published its final decision.[340]

The ESCV's GSL payments scheme is set out in in its Electricity Distribution Code and Public Lighting Code. The ESCV states in its final decision that its changes strengthen the incentive for distributors to improve the level of service for the worst served customers.[341]

The ESCV changes to the GSL payments scheme will commence from 1 January 2016.[342] The ESCV expects that the AER will consider the additional costs associated with the proposed GSL payments scheme in making its final determination.[343]

The ESCV's changes to the Electricity Distribution Code and Public Lighting Code (as applicable) include the following:[344]

- increased GSL payments for 'annual duration of unplanned interruptions';
- increased GSL payments and reduced thresholds for 'annual frequency of unplanned sustained interruptions';
- the introduction of GSL payments for 'duration of sustained unplanned interruptions';
- increased GSL payments for 'annual frequency of momentary interruptions';
- increased GSL payments for 'on time for appointments';
- increased GSL payments for 'new connections';
- increased GSL payments for 'public light repairs'; and
- additional exclusion criteria for load shedding events.

Having regard to the significant changes determined by ESCV, we have revised our forecast GSL payments for the 2016–2020 regulatory control period on the basis of ESCV's final decision.

We have therefore prepared our forecast as follows:

- we adjusted our actual GSL payments for 2010–2014 as if the new thresholds and rates in the ESCV's final decision had applied in those years. We prepared the forecast for the new GSL payment obligation in respect of 'duration of sustained unplanned interruptions' on the basis of the data for 2010–2014 as if that requirement had been in place;
- we then escalated those GSL payment figures for each year of the 2010–2014 period into 2015 dollars;
- finally, we calculated an average of the GSL payment figures for each year of the 2010–2014 period in 2015 dollars and escalated this average for output growth over the 2016–2020 regulatory control period. As noted above, the AER did not escalate its forecast for GSL payments for output growth or other components of the rate of change. We consider that it is appropriate to escalate the forecast for output growth because by their very nature GSL payments would be expected to increase as the size of our network and quantity of services

339 ESCV, *Review of the Victorian electricity distributors' GSL payment scheme, draft decision,* 17 November 2015.

340 ESCV, *Review of the Victorian electricity distributors' GSL payment scheme, final decision,* 23 December 2015.

341 ESCV, *Review of the Victorian electricity distributors' GSL payment scheme, final decision,* 23 December 2015, p. (iii).

342 ESCV, *Review of the Victorian electricity distributors' GSL payment scheme, final decision,* 23 December 2015, p. (iii).

343 ESCV, *Review of the Victorian electricity distributors' GSL payment scheme, final decision,* 23 December 2015, p. 76.

344 ESCV, *Review of the Victorian electricity distributors' GSL payment scheme, final decision,* 23 December 2015, pp. 76–80.

we supply increases. Further, if our base year operating expenditure was not adjusted to remove actual GSL payments for 2014 (and include forecast GSL payments for the 2016–2020 regulatory control period), the rate of change would apply to those actual GSL payments as a component of our base year operating expenditure. It is therefore appropriate to at least escalate the forecast payments for output growth over the 2016–2020 regulatory control period.

In addition, in its final decision the ESCV proposes to develop a requirement to monitor and record quality of supply data for each customer with a smart meter installed.[345] In particular, the ESCV will require us to monitor and record the number of times the voltage supplied to each customer with a meter installed under the Advanced Metering Infrastructure (**AMI**) program is outside the specified range of steady state voltages for more than one minute. The ESCV considers that this will provide it with quality of supply data to facilitate the introduction of a quality of supply measure into its GSL payments scheme for the 2021–2025 regulatory control period.

As explained in our response to the ESCV's draft decision, under our current practices we record steady state voltage variations at the customer level only during targeted trials or when initiated by our customers.[346] We also monitor and record steady state voltage levels, in accordance with the requirements in the Electricity Distribution Code, at zone substations and at the end of a feeder from each zone substation.

Our IT infrastructure does not currently enable us to handle the potential volume of data which may be required to be recorded, retrieved and stored under the new obligation proposed by ESCV. For clarity, the ESCV stated that we were of the view that the number of our customers experiencing poor quality of supply is low. A more correct interpretation of our submission to the ESCV is that the number of customer complaints received relating to poor quality of supply is low. As the ESCV's proposed requirement is to proactively monitor *all* meters installed under the AMI program, the number of complaints received should not be used as a proxy for the volume of meters that may be experiencing voltage variations outside of the Electricity Distribution Code requirements.

We will have to incur additional operating expenditure to enable us to record, retrieve and store steady state voltage excursions for each and every customer with a meter installed under the AMI program. The most efficient option for complying with the ESCV's proposed requirement is to engage our meter vendors to introduce refined functionality into the AMI meter firmware. This would result in a once off increase in operating expenditure in 2016. An alternate, more expensive option, would be to increase our IT storage and assessment capabilities (to manage greater volumes of data) and install additional AMI communications network devices in order to handle larger than anticipated data volumes across our mesh network. However, in addition to being more expensive, this option will present greater technical risk.

Accordingly, we have included in our forecast of GSL payments for the 2016–2020 regulatory control period additional expenditure in 2016 for the ESCV's requirement to monitor and record quality of supply data for each customer with a smart meter installed. The following table shows the net adjustment to our base year operating expenditure for GSL payments for each year of the 2016–2020 regulatory control period.

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[345] ESCV, *Review of the Victorian electricity distributors' GSL payment scheme, final decision,* 23 December 2015, pp. 32–34.

[346] CitiPower and Powercor, *Submission on ESCV draft GSL decision,* 4 December 2015.

Table 6.1 GSL payments ($ million, 2015)

GSL payments	2016	2017	2018	2019	2020	Total
Less: GSL payments	-0.1	-0.1	-0.1	-0.1	-0.1	**-0.4**
Add: GSL payments	0.4	0.1	0.1	0.1	0.1	**0.7**
Net adjustment	**0.3**	**-0.0**	**-0.0**	**-0.0**	**-0.0**	**0.3**

Source: CitiPower
Notes: Totals may not add due to rounding.

6.2.5 Debt raising costs

For the reasons set out in our regulatory proposal, we maintain that the debt raising costs included in our regulatory proposal reflect the prudent and efficient costs required to achieve the operating expenditure objectives, and reflect a realistic expectation of the cost inputs required to achieve those objectives. However, in line with the AER's preliminary determination, we have revised our regulatory proposal to include only debt raising transaction costs (and not liquidity costs or three month ahead financing).

Our proposal is conservative (in that it may lead to us being undercompensated) having regard to the combined effect of our acceptance of the AER's decision on debt raising costs, new issue premium and inflation in circumstances where, on the evidentiary material, this results in under-compensation of our business for these costs.

Initial regulatory proposal

We proposed total debt raising costs (of 19.6 basis points per annum) as forecast by Incenta Economic Consulting (**Incenta**).[347]

AER's preliminary determination

The AER rejected our proposed total debt raising costs and substituted its own forecasts.[348] The AER accepted the method we proposed for estimating debt raising transaction costs but, because the preliminary decision departed from our proposed rate of return and regulatory asset base (**RAB**) values for the 2016–2020 regulatory control period, the AER revised our estimate of those debt raising transaction costs and indicated it would update this estimate again in its final decision. The AER concluded that our proposed liquidity costs and three month ahead financing costs did not satisfy the operating expenditure objectives.

Our response to the AER's preliminary determination

Debt raising costs are costs incurred in raising new debt or refinancing existing debt. Consistent with the approach previously adopted by the AER, in our regulatory proposal, we proposed to remove debt raising costs from our base year operating expenditure and include forecast debt raising costs for the 2016–2020 regulatory control period in our forecast operating expenditure as an adjustment to the base year expenditure.

Our proposed total debt raising costs (as forecast by Incenta) comprised three components:[349]

- the cost of issuing bonds based on an assumed debt portfolio;

347 CitiPower, *Regulatory proposal 2016–2020*, April 2015, appendix F, p. 7.

348 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-618.

349 CitiPower, *Regulatory proposal 2016–2020*, April 2015, appendix F, p. 7.

- the cost of establishing and maintaining the bank facilities required to meet liquidity requirements for maintaining an investment grade credit rating; and
- the cost of refinancing debt three months ahead of the refinancing date, which is also required to maintain an investment grade credit rating.

The AER accepted the first of these components (debt raising transaction costs) and Incenta's method for estimating these costs.[350] The forecast reflected in the AER's preliminary determination was lower than we had proposed, however, due to the lower value of the opening and projected RAB and the lower rate of return determined by the AER.[351]

The AER did not accept our proposed debt raising costs associated with bank facilities to maintain liquidity or the costs associated with refinancing three months ahead of the refinancing date.[352] The AER indicated that it did not accept these costs for the reasons set out in its transmission determination regarding TransGrid, which it considered neither we nor Incenta had engaged with.[353] The AER stated in the TransGrid decision that it did not allow these components of debt raising costs:[354]

> *primarily because the PTRM's timing assumptions already provide adequate compensation for the timing of revenue compared to expenses (liquidity related costs), to the extent that these cost streams are necessary.*

The AER referred to an estimate of bias in favour of the service provider in the PTRM in a 2002 report by the Allen Consulting Group Pty Ltd (**ACG**) to the Australian Competition and Consumer Commission, which the AER stated exceeded the estimate proposed by TransGrid for the components of debt raising costs rejected by the AER.

For the reasons set out in our regulatory proposal, we maintain that the debt raising costs included in our regulatory proposal reflect the prudent and efficient costs required to achieve the operating expenditure objectives, and reflect a realistic expectation of the cost inputs required to achieve those objectives. For the same reasons, if they were treated instead as a component of the return on debt, the debt raising costs in our regulatory proposal reflect the efficient financing costs of a benchmark efficient entity. However, in line with the AER's preliminary determination, we have revised our regulatory proposal to include only debt raising transaction costs (the first component of total debt raising costs described above).

We observe that the AER has not sought to quantify the alleged compensation provided through the PTRM's cashflow timing assumptions. The quantum of any such compensation turns on a comparison of the PTRM cashflow timing assumptions with our actual cashflow timings. The AER has not sought to perform that analysis. Accordingly, we consider that our approach to determining debt raising costs is conservative (in that it may lead to us being undercompensated) given that we have not included our proposed liquidity costs and three month ahead financing costs in our revised regulatory proposal. Our revised regulatory proposal is also conservative having regard to the combined effect of our acceptance of the AER's decision on debt raising costs, new issue premium and inflation in circumstances where, on the evidentiary material, this results in under-compensation of our business for these costs.

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350 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-618.

351 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-618 and 3-620.

352 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-618.

353 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-620 to 3-621.

354 AER, *Final decision TransGrid transmission determination 2015-16 to 2017-18*, April 2015, p. 3-544.

As we did not incur debt raising costs in our 2014 base year, the net adjustment to our base year operating expenditure each year is equal to our debt raising costs forecast for that year. This forecast is captured in our PTRM.

6.2.6 Reclassification of IT metering expenditure

Initial regulatory proposal

In our regulatory proposal, we included an adjustment to base year operating expenditure for the reclassification of IT metering operating expenditure from metering services to standard control services.

As set out in appendix F of our regulatory proposal, for the purposes of the 2016–2020 regulatory control period we examined the appropriate allocation of our 2014 base year IT operating expenditure between standard control services and metering services.[355] The impetus for this examination was because IT systems which we had upgraded or replaced to facilitate the AMI rollout are now, with the completion of the AMI rollout, used wholly or primarily to deliver standard control services.

In summary, to implement the Victorian Government's mandated rollout of AMI across our network we undertook a complete transformation of our IT infrastructure and systems that support metering, billing and market interactions, including introducing new systems and modifying existing systems.[356] During the 2011–2015 regulatory control period we recovered a portion of the operating costs associated with the new and upgraded IT systems in accordance with the Advanced Metering Infrastructure Order in Council (**AMI OIC**). Accordingly, in the 2014 base year, a proportion of the operating expenditure associated with operating and maintaining certain IT systems was recovered under the AMI OIC. While many of our IT systems originally required upgrading to facilitate the AMI rollout, these systems are now, with the completion of the AMI roll out, predominantly used to deliver standard control services.

Whether or not we own or operate the metering assets, we need to operate and maintain our IT systems in order to continue to deliver standard control services. Accordingly, for the purposes of the 2016–2020 regulatory control period, we assessed the use of each of the IT systems or programs for which we recovered a proportion of operating costs under the AMI OIC during the 2011–2015 regulatory control period. Where possible, we quantified the proportion of the system used for metering services and that used for standard control services consistent with clause 6.5.6(b)(2) of the Rules and the AER's *Cost allocation guidelines*.[357]

In addition, we commissioned Ernst & Young to review our proposed re-classification of our operating expenditure associated with certain IT systems from metering to standard control services. Ernst & Young found our allocation to be consistent with the AER's *Cost allocation guidelines* and our approved CAM.[358]

AER's preliminary determination

The AER rejected our proposed adjustment to base year operating expenditure for the reclassification of IT metering operating expenditure from metering services to standard control services.

The AER determined to allocate all costs formerly regulated under the AMI OIC to alternative control services.[359] The AER considered that it was preferable to adopt a consistent approach to the allocation of metering costs across Victorian service providers. The AER noted that while metering services are not currently subject to

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355 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix F, p. 10.

356 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix F, p. 10.

357 CP PUBLIC APP F.1 - AER, *Electricity distribution network service providers, Cost allocation guidelines,* June 2008.

358 CP PUBLIC APP F.3 - Ernst & Young, *CitiPower and Powercor Australia, Allocation of IT system operating expenditure*, April 2015, p.2.

359 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-45.

competition, they likely will be in the near future and the cost allocation approaches applied by incumbent providers have the potential to affect competition from new entrants and competition between Victorian distributors. The AER noted that it is required to develop and publish a *Distribution ring fencing guideline* by 1 December 2016 and that it considered any cost allocation issues relating to metering costs would be best dealt with in the development of the guideline in accordance with a nationally consistent approach.

The AER considered that allocating all costs formerly regulated under the AMI OIC to metering would help in promoting transparency around trends in AMI and standard control services expenditure.

Our response to the AER's preliminary determination

We oppose the AER's preliminary determination to reject our proposed adjustment to base year operating expenditure for the reclassification of IT metering operating expenditure from metering services to standard control services.

As set out in our regulatory proposal, our proposed adjustment was made in order to properly allocate IT operating expenditure to the type of services the expenditure primarily relates to, being standard control services or alternative control services.[360]

We continue to maintain that the 2014 operating expenditure associated with the following IT systems should be re-classified from metering services to standard control services because, as detailed in our regulatory proposal, these IT systems are used either wholly or primarily for the provision of our standard control services:[361]

- Itron Enterprise Edition, which provides a platform for data collection, validation, storage and processing;
- Itron Market Transaction System, which manages data communication with external market parties, for example providing consumption and billing data to retailers and the wholesale market transaction system;
- Ventyx Service Suite, which is a system used for the scheduling, dispatching, resourcing and tracking of the status of field work;
- data warehousing and analytics systems, including SAS (a statistical forecasting program), SAP (used for business and intelligence reporting) and our data warehousing platform used for the storage of large volumes of data; and
- Oracle Utility Service Bus, which orchestrates business process logic required to perform trans-system functions and facilitates communications across all the different IT systems and programs by enabling the different infrastructures to communicate effectively with each other and thereby utilise the same information.

The operating and maintenance expenditure associated with the above IT systems relates to:[362]

- external vendor charges for licencing fees and software and hardware support, known as support and maintenance costs; and
- labour costs associated with maintaining the systems, for example undertaking day to day operational support activities, system testing, back-ups, installing upgrades, response to user-based service calls, management of capacity, and ensuring operational performance and stability.

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[360] CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix F, p. 10.

[361] CitiPower, *Regulatory Proposal 2016–20*, April 2015, appendix F, pp. 10-13.

[362] CitiPower, *Regulatory Proposal 2016–20*, April 2015, appendix F, pp. 11.

We describe in detail in appendix F to our regulatory proposal how and why these systems and the associated operating expenditure is used in the provision of standard control services.[363] This is also described in Ernst & Young's report attached to our regulatory proposal.[364] Except for the Ventryx service suite which was specifically implemented to support our AMI rollout, we have always used these IT systems, at least in part, for the provision of standard control services. However, each of these IT systems was upgraded to facilitate the AMI rollout and the AMI OIC allowed enhancements of IT systems to be recovered through AMI charges.[365] With the completion of the AMI rollout these systems are now used to deliver standard control services. We observe that as a registered participant we must comply with AEMO procedures determined in accordance with the Rules. In compliance with those AEMO procedures, as a local network service provider we must be able to receive data, bill, store data, keep records and undertake various activities with respect to data (including aggregate, validate, reconcile, substitute and estimate data). We require these IT systems in order to undertake those activities regardless of whether or not we provide any metering services.

We consider that allocating these costs to standard control services results in an operating expenditure forecast which is more consistent with the operating expenditure criteria. Similarly, the removal of those costs from alternative control regulated metering services, results in an operating expenditure forecast for those services which is more consistent with that of an efficient and prudent operator of those services.

As noted above, the AER correctly observed in its distribution determination that the cost allocation approaches applied by incumbent providers have the potential to affect competition from new entrants and competition between Victorian distributors.[366] While the AER may have been suggesting that we would be unfairly advantaged relative to our competitors if we allocated certain IT metering expenditure to standard control services, the correct position is that if we are burdened with carrying standard control related systems costs in our metering charges, we would be uncompetitive relative to our competitors and potential competitors. The impact of including those costs in our operating expenditure for the regulated type 5-6 and smart metering service is likely to have a distorting impact on price signals following the introduction of metering contestability as our tariffs will be overstated. Accordingly, the error is likely to inefficiently encourage substitution away from us to other parties (for example, where we can provide metering services at lower cost). The AER's approach would artificially create meter churn where this would not be in the long term interests of the NEO.

Further, while the AER considered that allocating costs formerly regulated under the AMI OIC to metering would help in promoting transparency around trends in AMI and standard control services expenditure, to the contrary allocating operating expenditure associated with these IT systems to metering will be detrimental to transparency as stand-alone metering service providers would only include AMI costs in their operating expenditure for the regulated type 5-6 and smart metering service whereas, under the AER's approach, our operating expenditure for that service would include both AMI and standard control services costs.[367] As such, a failure by the AER to properly allocate our IT metering expenditure between operating expenditure and alternative control services will have the result that the trend in AMI expenditure will not reflect the true cost of providing AMI services, and nor will the trend in operating expenditure for standard control services reflect the true cost of providing standard control services.

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[363] CitiPower, *Regulatory Proposal 2016–20*, April 2015, appendix F, pp. 11-13.

[364] CP PUBLIC APP F.3 - Ernst & Young, *CitiPower and Powercor Australia, Allocation of IT system operating expenditure*, April 2015, p. 2.

[365] Under S2.1(a)(v) of the AMI OIC, operation, maintenance and enhancement of IT applications, systems and infrastructure falls within scope of the AMI OIC and such IT applications, systems and infrastructure are described in S2.4 of the AMI OIC.

[366] AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.

[367] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-45.

Our approach is consistent with the approach proposed by the Victorian Department of Economic Development, Jobs, Transport and Resources (**DEDJTR**) in its submission to the AER on the Victorian price reset for 2016–2020.[368] The DEDJTR considers that in deciding whether the transfer of expenditure from metering services to other distribution services is appropriate, the AER needs to apply the principle that was originally adopted in determining the first separate price control for metering services for the 2006–2010 regulatory control period being:

> *… the costs of those IT systems that are required for all customers, regardless of whose meter is installed, should be recovered through the [Distribution Use of System] DUoS price control … The costs of those IT systems that are required only for customers who have the distributor's meter installed should be recovered through the metering price control.*

Retaining these IT system costs in regulated metering alternative control services would result in metering customers effectively cross-subsidising distribution customers. Following the introduction of metering contestability, these two sets of customers may no longer be closely aligned as some of our distribution customers may choose alternative metering providers. The importance of allocating costs to the proper cause will therefore become increasingly important over the 2016–2020 regulatory control period.

While the AER declined to approve our proposed adjustment on the basis that there should be a nationally consistent approach to allocation of metering costs, there is no requirement under the Rules for there to be consistency across distributors with respect to the allocation of such costs.[369] Further, since distributors have utilised different IT systems from each other to achieve the AMI rollout and those IT systems were in different stages of development in terms of smart meter capabilities prior to and subsequent to completion of that rollout (and thus required different expenditure amounts to facilitate the roll out), it is unlikely that such consistency could be achieved under the AER's approach.

In addition, the AER's refusal to correctly allocate our IT costs related to our provision of standard control services is contrary to the revenue and pricing principles in section 7A of the National Electricity Law (**Law**). In particular, section 7A(3)(a) of the Law provides that we should be provided with effective incentives in order to promote efficient investment in our distribution system which we use to provide direct control network services. A failure to allocate our IT costs to standard control services interferes with our incentive to invest in our systems used to provide standard control services. Under the AER's approach AMI costs will continue to cross-subsidise standard control services in a manner which is inconsistent with cost reflective pricing—in particular, the network pricing objective in clause 6.18.5(a) of the Rules being that the tariffs that we charge in respect of our provision of direct control services to a retail customer should reflect our efficient costs of providing those services to the retail customer.

Ernst & Young found our allocation of IT metering expenditure to be consistent with the AER's *Cost allocation guidelines* and our approved CAM.[370] The AER states that its decision regarding allocation of IT metering expenditure is not a 'straightforward application of our approved Cost Allocation Method because of the wider regulatory context related to metering'.[371] We consider that the scheme of chapter 6 of the Rules is that the AER should assess our operating expenditure forecast and determine any substitute forecasts in accordance with our approved CAM. This is evident from:

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368 Victorian Department of Economic Development, Jobs, Transport & Resources, *Submission to Victorian electricity distribution pricing review - 2016 to 2020*, 13 July 2015, pp. 5-6.

369 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-45.

370 CP PUBLIC APP F.3 - Ernst & Young, *CitiPower and Powercor Australia, Allocation of IT system operating expenditure*, April 2015, p. 2.

371 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 16-38.

- the explicit obligation in the Rules for us to prepare our operating expenditure forecast in accordance with the principles and policies set out in the AER approved CAM (clauses 6.5.6(b)(2) and 6.15.1); and
- the Rules' provision for the AER to assess those principles and policies in determining whether or not to approve the CAM and the limitations on the AER's discretion to so determine established by the Rules' requirements for the CAM specified in clause 6.15 of the Rules (clause 6.15.4).

Accordingly, the AER should allocate our IT metering expenditure in a manner that is consistent with our CAM, being the manner proposed in our regulatory proposal, which Ernst & Young confirmed was consistent with our approved CAM and the AER's *Cost allocation guidelines*.

Finally, in its preliminary determination, the AER states that it proposes to deal with any cost allocation issues relating to metering costs in its *Distribution ring fencing guideline* to be developed by December 2016. We consider that it is incorrect and unreasonable for the AER to defer its decision on the proper allocation of our IT operating expenditure between metering and standard control services in this manner. Essentially, the AER is abdicating the making of its decision on this matter on the basis of an irrelevant consideration (being its desire to determine the matter at a later time and in another process, i.e. its *Distribution ring fencing guideline*). Instead, the AER must make a decision in our distribution determination for the 2016–2020 regulatory control period that is correct and reasonable having regard to relevant considerations, including the principles established by the Rules for cost allocation and our CAM. We also note in this regard that deferring a decision on the proper allocation of our IT operating expenditure until 2017 is not an option because it will not take effect until the next regulatory control period commencing 2021.

The following table shows the forecast impact of reclassifying IT metering operating expenditure over the 2016–2020 regulatory control period. This forecast reflects the increase in standard control services base year operating expenditure and the corresponding decrease in metering services base year operating expenditure.

Table 6.2 IT metering expenditure–adjustment to standard control services ($ million, 2015)

Base year adjustment	2016	2017	2018	2019	2020	Total
IT metering expenditure	2.9	2.9	2.9	2.9	2.9	**14.6**

Source: CitiPower, *Regulatory Proposal 2016–2020,* April 2015, appendix F, p. 13.

6.2.7 Scrapping of assets

In its preliminary determination, the AER removed $0.1 million in reported operating expenditure for losses associated with the scrapping of assets.[372] The AER observed that losses on the scrapping of assets are accounting records of the shortfalls between the proceeds from selling assets and their accounting written down values. The AER considered that as a loss on the scrapping of an asset is an accounting adjustment to expenditure, rather than an actual outlay made by us in providing network services, it was not something which should be recovered from our consumers. The AER noted that consistent with this approach, it proposed to exclude this cost from the efficiency benefit sharing scheme in the 2016–2020 regulatory control period.

We object to the AER's removal of $0.1 million from our base year operating expenditure for losses associated with the scrapping of assets. The AER has removed losses on the scrapping of assets from our operating expenditure on the assumption our reported operating expenditure is inclusive of these losses. This is not the case. Currently we report the net gain/loss on the sale of assets within the income worksheet of the annual

372 AER, *Preliminary decision, CitiPower distribution determination 2016–20, October 2015*, p. 7-45.

RIN.[373] It is evident from that worksheet, and our regulatory accounts, that any net gain/loss on the sale of assets does not form part of our base operating expenditure and, accordingly, that it is incorrect to adjust our base operating expenditure for losses on the scrapping of assets.

From a regulatory viewpoint, when we purchase a network asset it is included in our regulatory asset base (**RAB**). When we sell a network asset, we adjust the RAB for the cash received for that asset. The gross cash proceeds from the sale of assets are reported as disposals in the capital expenditure worksheet of the annual RIN and modelled as an adjustment (reduction) to the RAB roll forward model.[374]

As a result, assets which are purchased and then subsequently scrapped form part of our RAB calculation and are not included in our operating expenditure. Accordingly, as losses associated with the scrapping of assets were not included in our base operating expenditure, it is incorrect for the AER to make a negative adjustment to our base operating expenditure for losses associated with the scrapping of assets.

6.2.8 Our revised regulatory proposal

The following table sets out our net adjustments to our 2014 base year operating expenditure in our revised regulatory proposal.

Table 6.3 Net base year adjustments ($ million, 2015)

Base year adjustments	2016	2017	2018	2019	2020	Total
Less: base year GSL payments	-0.1	-0.1	-0.1	-0.1	-0.1	**-0.4**
Add: forecast GSL payments	0.4	0.1	0.1	0.1	0.1	**0.7**
Less: base year DMIA	-0.4	-0.4	-0.4	-0.4	-0.4	**-2.1**
Total	**-0.1**	**-0.4**	**-0.4**	**-0.4**	**-0.4**	**-1.8**

Source: CitiPower
Notes: Our forecasts for DMIA and debt raising costs are not included in this table as they are captured separately in our revenue requirement.

The following table sets out our adjustments to our 2014 base year operating expenditure relating to the reclassification of services in our revised regulatory proposal.

373 CitiPower, *2014 Annual RIN, Appendix B Financial Information (public),* worksheet '1a. income', cell D18. For clarity, in response to an AER information request, we informed the AER that we incurred $0.1 million ($2014) losses on the scrapping of assets in 2014, the majority of which were for motor vehicles. The AER did not explain why it was requesting the information, it simply asked whether we had incurred any losses on the scrapping of assets in 2014. In light of the full context of the AER's request (having regard to the AER's preliminary determination), it is apparent the estimate we provided was incomplete. Consistent with our statutory accounts, the relevant value we should have reported is $0.05 million. In any event, for the reasons set out in the main text, it is incorrect for the AER to have made an adjustment to our base operating expenditure for losses associated with the scrapping of assets.

374 CitiPower, *2014 Annual RIN, Appendix B Financial Information (public),* worksheet '3a. capex - total', table 6.

Table 6.4 Service reclassification ($ million, 2015)

Base year adjustments	2016	2017	2018	2019	2020	Total
Supply abolishment	0.8	0.8	0.8	0.8	0.8	**3.9**
Category RIN alignment	0.2	0.2	0.2	0.2	0.2	**1.0**
Reclassification of IT metering expenditure	2.9	2.9	2.9	2.9	2.9	**14.6**
Total	**3.9**	**3.9**	**3.9**	**3.9**	**3.9**	**19.5**

Source: CitiPower

In addition, as noted above, in our revised regulatory proposal, we have accepted the AER's adjustment to our base year operating expenditure due to changes in our capitalisation policy. That adjustment results in a $88.4 million ($2015) increase in total forecast operating expenditure for the 2016–2020 regulatory control period from our 2014 base year in operating expenditure.

6.3 Rate of change

6.3.1 Rule requirements

Clause 6.5.6(c) of the Rules provides that the AER must accept the proposed operating expenditure forecast that we include in our building block proposal if the AER is satisfied that the forecast operating expenditure for the 2016–2020 regulatory control period reasonably reflects the operating expenditure criteria.

Under the base-step-trend methodology for deriving efficient operating expenditure, an 'annual rate of change' is applied to base year costs. The rate of change formula for operating expenditure in the AER's *Expenditure forecast assessment guideline* is:[375]

$$\textit{Rate of change} = output\ growth^t + real\ price\ growth^t - productivity\ growth^t$$

The rate of change is expected to provide an efficient escalation of base year costs for a proportional increase in operating costs for network growth, real price increases for cost inputs, and to account for expected changes in productivity for the 2016–2020 regulatory control period.

6.3.2 Initial regulatory proposal

In our regulatory proposal, we developed forecasts of real price growth, output growth and productivity growth and applied these to develop our operating expenditure forecasts. We described our approach to output growth and productivity growth in chapter 10 of our regulatory proposal. We set out our approach to real price growth in chapter 7 of our regulatory proposal.

Our response to the AER's preliminary determination on real price growth is set out in chapter 4 of our revised regulatory proposal. Accordingly, the summary of our initial regulatory proposal with respect to real price growth is also contained in chapter 4.

Output growth

For our regulatory proposal, we used the average output growth of four econometric models to forecast output growth.[376] Three of the econometric models were developed by expert econometricians, Frontier Economics,

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375 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 23.

376 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, pp. 166-171.

and the fourth model was developed by Economic Insights and applied by the AER in its final decisions for New South Wales, Australian Capital Territory, Queensland and South Australian distributors.

Productivity growth

For our regulatory proposal, we applied a zero productivity adjustment in our rate of change forecasts on the basis that we did not consider it appropriate to apply pre-emptive productivity adjustments to our operating expenditure forecast and there was no evidence to justify the making of a positive adjustment.[377] In doing so, we observed that the AER's benchmarking analysis suggests that the distribution industry has exhibited declining productivity over the last eight years.

6.3.3 AER’s preliminary determination

As our response to the AER's preliminary determination on real price growth is set out in chapter 4 of our revised regulatory proposal, our summary of the AER's preliminary determination with respect to real price growth is also contained in chapter 4. We provide the following summary of the AER's preliminary determination with respect to output growth and productivity growth.

Output growth

The AER was not satisfied that our proposed average annual output growth of 1.8 per cent for the 2016–2020 regulatory control period reflects the increase in output an efficient service provider requires to meet its operating expenditure objectives.[378] The AER forecast an average annual output growth of 1.2 per cent for the 2016–2020 regulatory control period.

The AER was not satisfied that:

- the output measures and forecasting method we adopted to forecast output growth reflected a realistic expectation of the output growth we would experience;
- our forecast of customer numbers reasonably reflected the increase in customer numbers we would need to serve; and
- our forecast of maximum demand reflected a realistic expectation of the demand forecast required to achieve the operating expenditure objectives.

The AER adopted the following output growth measures and weightings:[379]

- customer numbers (67.6 per cent);
- circuit length (10.7 per cent); and
- ratcheted maximum demand (21.7 per cent).

The AER stated that these output measures are consistent with the output variables used by Economic Insights to measure productivity in its operating expenditure cost function in its report entitled *Economic benchmarking assessment of operating expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014.

To forecast output growth, the AER used:

- the forecast circuit length which we reported in our reset RIN to produce an average annual growth rate of 0.66 per cent for circuit length;[380]

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377 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, pp. 171-172.

378 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-64.

379 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-64 to 7-65.

- AEMO's 2014 transmission connection point maximum demand forecasts to produce an average annual growth rate of 0.67 per cent for ratcheted maximum demand. The AER did not use the forecast maximum demand numbers we reported in our reset RIN as it was not satisfied that our forecast of maximum demand reflected a realistic expectation of the demand forecast required to achieve the operating expenditure objectives;[381] and
- an historic average growth rate of residential customer numbers of 1.25 per cent per year, together with the forecasts of non-residential and unmetered customer numbers reported in our reset RIN to produce an annual growth rate of 1.39 per cent for customer numbers.[382]

Productivity growth

The AER applied a zero per cent productivity growth forecast in its estimate of the overall rate of change based on its expectations of the forecast productivity for an efficient service provider in the short to medium term.[383] As noted above to reach its estimate of forecast productivity, the AER considered Economic Insights' economic benchmarking, our proposal, the AER's expectations of the distribution industry in the short to medium term, and observed productivity outcomes from electricity transmission and gas distribution industries.[384] The AER stated that it applied a zero productivity forecast for the following reasons:[385]

- while data from the 2006–2013 period indicates negative productivity for distributors on the efficient frontier, the AER does not consider this is representative of the underlying productivity trend and its expectations of forecast productivity in the medium term; and
- measured productivity for electricity and gas distribution industries are positive for the 2006–2013 period and are forecast to be positive.

6.3.4 Our response to the AER’s preliminary determination

As noted above, our response to the preliminary determination with respect to real price growth is set out in chapter 4 of our revised regulatory proposal. We provide the following response to the preliminary determination with respect to output growth and productivity growth.

Output growth escalation

We have prepared our revised regulatory proposal with respect to output growth escalation to be consistent with the AER's preliminary determination on:

- customer number forecasts; and
- circuit length forecasts.

For the reasons set out in chapter 5 of our revised regulatory proposal, we dispute the AER's preliminary determination on demand forecasts.

In addition, rather than using one econometric model to determine output growth escalation as the AER has done in its preliminary determination, we maintain that as a matter of principle it is preferable to take an average

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380 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-65.

381 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-66.

382 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-67.

383 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-69.

384 AER, *Preliminary decision, CitiPower distribution determination 2016–20* October 2015, p. 7-69.

385 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-69.

of the results of several econometric models as we did for the purposes of our regulatory proposal. This is because taking an average of the results of multiple econometric models:[386]

- enables the impact of a broader range of operating expenditure cost drivers to be captured in the output growth escalator;
- addresses the statistical limitations associated with a small sample size and high correlations between cost drivers; and
- will likely produce a more accurate forecast than using a single model.

Further, the AER's primary reason for using the Economic Insights model appears to be because it is consistent with the output variables Economic Insights used in its benchmarking analysis to measure productivity in its operating expenditure cost function.[387] We observe that it is not necessary for the AER to seek to achieve consistency with the benchmarking model, particularly since in determining forecast productivity growth it did not seek to ensure consistency by applying the negative productivity growth factors determined through Economic Insights' economic benchmarking model. Rather, the AER determined to apply zero per cent forecast productivity growth on the basis of its expectations of the forecast productivity for an efficient service provider in the short to medium term having regard to Economic Insights' economic benchmarking, our proposal, the AER's expectations of the distribution industry in the short to medium term, and observed productivity outcomes from electricity transmission and gas distribution industries.[388] Given this, there is no basis for the mechanistic application of the output measures applied in Economic Insights' benchmarking analysis.

Nonetheless, for the purposes of determining output growth escalation in our revised regulatory proposal we have used the AER's model and substituted our revised demand forecasts for those used by the AER in its preliminary determination.

Productivity growth

We observe that the AER has not applied the negative productivity growth factor determined through Economic Insights' econometric modelling, but has assumed zero per cent productivity growth without providing conclusive evidence to support why it expects productivity growth will not continue to be negative into the 2016–2020 regulatory control period. Further, if the AER were to consistently apply its economic benchmarking model throughout the rate of change formula (as it did so for output growth), then the AER should have applied a negative productivity adjustment.

Nonetheless, we accept the AER's preliminary determination to apply a zero per cent productivity growth forecast in its estimate of the overall rate of change. The application of a zero per cent productivity growth forecast is consistent with our regulatory proposal, although we proposed a zero per cent productivity growth for different reasons to the AER. In particular, we noted in our regulatory proposal that we did not consider it appropriate to apply pre-emptive productivity adjustments to our operating expenditure forecast and there was no evidence to justify the making of a positive adjustment.[389]

In its submission to the AER on the 2016–2020 Victorian price reset, the DEDJTR states that it 'expects an additional level of productivity improvement associated with the rollout of smart meters so that the DNSP's

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386 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, p. 167.

387 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-64 to 7-65.

388 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-68 to 73.

389 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, pp. 171-172.

customers are able to realise the benefits for their investment in the smart meter rollout'.[390] It is unclear what operating expenditure related productivity improvements DEDJTR has in mind. As the AER observes, DEDJTR has not identified or quantified the benefits of the AMI program it expects to be realised over the 2016–2020 regulatory control period.[391]

Benefits of the Advanced Metering Infrastructure (**AMI**) rollout which we have realised to date have largely been realised through savings in alternative control services operating expenditure and are already reflected in our base metering operating expenditure. Those benefits that concern standard control services operating expenditure are already captured in our operating expenditure forecast as they are reflected in our base year operating expenditure. Future benefits of the AMI rollout are expected to be related to capital expenditure, rather than operating expenditure. Access to AMI data mostly provides future capital expenditure savings, for example by enabling improved network and community safety and improved network investment decisions, including the potential to defer network augmentation. Further, the Victorian Government has advised that in Victoria demand tariffs will be subject to an opt-in only requirement for the 2017–2020 period.[392] This will reduce the up-take of cost reflective tariffs, relative to an opt-out policy and will reduce the potential benefits that can be realised from AMI over the 2016–2020 regulatory control period.

In making the assertion that Victorian distributors should realise efficiency gains from the rollout of smart meters, the DEDJTR refers to the decision by the UK economic regulator, the Office of Gas and Electricity Markets (**Ofgem**) in its revenue determination for UK distribution network operators for 1 April 2015 to 31 March 2023 to make an efficiency adjustment for smart grids, smart metering and other innovation.[393] Ofgem's adjustment was applied to total expenditure rather than operating expenditure and Ofgem noted that the savings from smart solutions were primarily related to reduced network reinforcement (augmentation), improved asset replacement and improved fault management, which are capital expenditure related savings.[394] In any event, Ofgem's smart grid efficiency adjustment was overturned on appeal by the Competition and Markets Authority on the basis that neither the evidence, nor the reasons put forward by the Gas and Electricity Markets Authority supported its decision to make the adjustment.[395]

In addition, following the introduction of metering contestability from 1 December 2017 as a result of the AEMC's *Expanding competition in metering and related services rule determination* of 26 November 2015, distributors will need to pay the relevant metering co-ordinator for access to AMI data from customers that are no longer the distributor's metering customers and metering co-ordinators are expected to price up to the marginal benefit of this information to the distributor as the AEMC proposes that the price for access to services provided by metering co-ordinators will not be regulated, but rather will be subject to commercial agreement.[396] As a result, there may be costs for data access during the 2016–2020 regulatory control period which would

390 Victorian Department of Economic Development, Jobs, Transport & Resources, *Submission to Victorian electricity distribution pricing review - 2016 to 2020*, 13 July 2015, p. 8.

391 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-72.

392 Minister for Energy and Resources, *Distribution network pricing arrangements*, November 2015.

393 Victorian Department of Economic Development, Jobs, Transport & Resources, *Submission to Victorian electricity distribution pricing review - 2016 to 2020*, 13 July 2015, p. 8.

394 Ofgem, *RIIO-ED1: Final determinations for the slow-track electricity distribution companies,* 24 November 2014, Overview, p. 34.

395 Competition & Markets Authority, *Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc v the Gas and Electricity Markets Authority, Final determination*, 29 September 2015, p. 71.

396 AEMC, *Rule Determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015, National Energy Retail Amendment (Expanding competition in metering and related services) Rule* 2015, 26 November 2015, pp. (xi) and 129 and clause 7.6.1(b) of the Rules as introduced by that Rule Determination (refer to AEMC, *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015 No. 12*), pp. 18–19.

offset any potential operating expenditure benefits realised in that period. Further, those costs could potentially be such as to make access to data prohibitive, or such access may not be available, for example if the metering co-ordinator's systems do not enable the capture and processing of the required data.

Having regard to the above, it is not appropriate to pre-emptively reduce operating expenditure forecasts for highly speculative productivity benefits which may or may not occur in the future due to the roll out of smart meters.

As the AER does not foreshadow making any AMI productivity adjustment in its preliminary determination, we would expect to be consulted on the making of any decision by the AER to introduce such an adjustment, including as to the rationale for it and its nature, quantification and implementation prior to the making of the final determination. The AER would be required to so consult under section 16(1)(b) of the Law which requires the AER to consult on material issues under consideration by it, in addition to the AER's common law obligation as an administrative decision maker.

6.3.5 Our revised regulatory proposal

In our revised regulatory proposal we have applied the overall rate of change set out in the following table.

Table 6.5 Rate of change in operating expenditure ($ million, 2015)

Operating expenditure	2016	2017	2018	2019	2020	Total
Real price growth	1.1	2.2	3.2	4.3	5.4	**16.2**
Output growth	2.0	3.3	5.1	6.4	7.7	**24.5**
Productivity	-	-	-	-	-	**-**
Total value of rate of change	**3.1**	**5.5**	**8.3**	**10.7**	**13.1**	**40.7**

Source: CitiPower

6.4 Step changes

6.4.1 Rule requirements

A step change comprises an adjustment made to base year operating expenditure when forecasting expenditure for the 2016–2020 regulatory control period for costs that are not captured in base operating expenditure or the rate of change.

As set out above, the AER is required to accept our forecast operating expenditure where it is satisfied that the forecast operating expenditure for the regulatory control period reasonably reflects the operating expenditure criteria in clause 6.5.6(c) of the Rules. If the AER is not so satisfied and, accordingly, does not accept our forecast of required operating expenditure, the AER must estimate our required operating expenditure that it is satisfied reasonably reflects the operating expenditure criteria (clauses 6.5.6(d) and 6.12.1(4)(ii) of the Rules).

The scope of operating expenditure step changes must be determined by reference to the statutory test for the AER's decision on our operating expenditure forecast in clauses 6.5.6(c) and 6.12.1(4)(ii) of the Rules. Having regard to clauses 6.5.6(c) and 6.12.1(4)(ii) of the Rules, the AER must accept a proposed step change where it is necessary for forecast operating expenditure to reasonably reflect the efficient costs of achieving the operating expenditure objectives in clause 6.5.6(a) of the Rules, the costs that a prudent operator would require to achieve those objectives, and a realistic expectation of the demand forecast and cost inputs required to achieve those objectives.

This is consistent with the AER's statement in its *Expenditure forecast assessment guideline* that '[s]tep changes may be added (or subtracted) for any other costs not captured in base opex or the rate of change that are required for forecast opex to meet the opex criteria'.[397] Similarly, in its *Explanatory statement expenditure forecast assessment guideline*, November 2013, the AER states:[398]

> *The rate of change may not capture all cost changes that reasonably reflect the opex criteria. For this reason, we will also add step changes to our opex forecast where they are necessary to produce a forecast that is consistent with the opex criteria.*

6.4.2 Initial regulatory proposal

In chapter 10 and appendix G of our regulatory proposal, we proposed the step changes set out in the below table.

Table 6.6 Operating expenditure step changes for 2016–2020 ($ million, 2015)

Step change	Total
Customer charter	0.2
Superannuation (accumulation members)	1.6
Monitoring IT security	2.0
[redacted]	[redacted]
Mobile devices	1.8
Customer Information System (**CIS**) Customer Relationship Management System (**CRM**)	2.2
Decommissioning zone substations	6.7
Total	**18.3**

Source: CitiPower, *Regulatory Proposal 2016–2020*, April 2015, p. 177.

6.4.3 AER's preliminary determination

In its preliminary determination, the AER declined to include the following of our proposed step changes in its operating expenditure forecast:[399]

- customer charter;
- superannuation (accumulation members);
- monitoring IT security;
- mobile devices; and
- decommissioning zone substations.

[redacted]

397 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

398 AER, *Explanatory statement expenditure forecast assessment guideline*, November 2013, p. 71.

399 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 7-78 to 7-87.

The AER included a proportion of our proposed step change in respect of our CIS and CRM system.[400]

Further, as noted above, the AER rejected our proposed adjustments to base year operating expenditure for regulatory reset costs and superannuation (defined benefit contributions) in the section of its preliminary determination concerning step changes.[401]

In addition, the AER indicated that we should address the net impact of the *Electrical Safety (Electric Line Clearance) Regulations 2015* (**2015 ELC Regulations**) in our revised regulatory proposal.[402]

6.4.4 Our response to the AER's preliminary determination

We have amended our regulatory proposal and prepared this revised regulatory proposal to be consistent with the AER's preliminary determination on the following step changes:

- customer charter;
- CIS and CRM system; and
- superannuation (accumulation members) (as noted in our response to the AER's preliminary determination regarding base year adjustments above, we have also prepared our revised regulatory proposal to be consistent with the AER's decision to reject our proposed adjustment to base year operating expenditure for our forecast defined benefit superannuation contributions).

As noted above in respect of the AER's consideration of our proposed adjustments to base year operating expenditure, we also have amended our regulatory proposal and prepared this revised regulatory proposal to be consistent with the AER's preliminary decision with respect to regulatory reset costs.

We dispute the AER's preliminary determination on step changes in respect of the following:

- monitoring IT security;
- mobile devices; and
- decommissioning zone substations.

[redacted]

In addition, we propose additional step changes for:

- the introduction of cost-reflective tariffs;
- RIN compliance; and
- the introduction of chapter 5A of the Rules.

The AER acknowledges that it must accept a proposed step change where it is necessary for the total forecast operating expenditure to satisfy the operating expenditure criteria.[403] This is also consistent with the AER's position in its *Expenditure forecast assessment guideline* that '[s]tep changes may be added (or subtracted) for any other costs not captured in base opex or the rate of change that are required for forecast opex to meet the opex criteria'.[404] Nonetheless, the AER proceeds to deny each of our proposed step changes that are not the

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400 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-74 to 7-86.

401 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-78 to 7-82.

402 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-87.

403 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-75.

404 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 24.

result of new or changed regulatory obligations primarily on the basis that our base year expenditure together with the rate of change is sufficient for our forecast operating expenditure to satisfy the operating expenditure criteria in clause 6.5.6(c) of the Rules. In particular, the AER refused our monitoring IT security, and decommissioning zone substations on this basis. [redacted]

Further, the AER assumes that for every forecast increase in operating costs for the 2016–2020 regulatory control period (other than costs that are the consequence of a change in regulatory obligation or explained by the rate of change), there will be a corresponding decrease in costs during that period. That is, the AER assumes that an increase in our operating expenditure during the 2016–2020 regulatory control period, will be perfectly off-set by some reduction in base year operating expenditure, except to the extent that it is explained by the rate of change or a change in regulatory obligation. The AER has no evidentiary basis for this assumption and fails to give any examples of cost reductions during the 2016–2020 regulatory control period which will off-set our proposed step changes.

It is not the case that our base year operating expenditure can fund large operating costs that we need to incur in 2016–2020 regulatory control period in order to maintain the quality, reliability and security of supply of standard control services and the safety, reliability and security of the distribution system through the supply of standard control services. This is particularly so, in circumstances where, as the AER recognises in its preliminary determination, we are one of the most efficient service providers in the NEM. Accordingly, consistent with the Rules requirements and the AER's own statements, we should be allowed step changes for operating expenditure that is necessary for our total forecast operating expenditure to satisfy the operating expenditure criteria, regardless of whether or not the cause of the increase in operating costs is a new or changed regulatory obligation.

We describe in more detail below why our proposed step changes should be allowed in setting out our response to the AER's preliminary determination on those step changes. We also describe our additional proposed step changes.

6.4.5 Monitoring IT security

We maintain that the AER should accept our proposed step change for monitoring IT security is necessary for our forecast operating expenditure to satisfy the operating expenditure criteria. In particular, it is necessary to maintain the quality, reliability and security of supply of standard control services and the safety, reliability and security of the distribution system through the supply of standard control services (clause 6.5.6(a)(3) and (4) of the Rules).

Initial regulatory proposal

In chapter 10 and appendix G of our regulatory proposal, we proposed a step change for the costs of engaging an external service provider to monitor our IT security systems on a 24 hour basis.[405] Our proposed step change was supported by the report entitled *CitiPower and Powercor Australia: Information security business case* which was provided as an attachment to our regulatory proposal.[406]

IT system breaches are a growing threat and managing these threats requires a proactive IT security program. Our IT and operating networks may be the target of individuals or organisations seeking to cause disruption to the electricity network, alter meter readings and/or access confidential corporate or customer information. Our current IT systems raise alerts for various security threats which require human intervention to determine the appropriate response. If active monitoring of these alerts were to only occur during business hours, an alert

405 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, pp. 178-179 and appendix G, pp. 8–13.

406 CP PUBLIC ATT 9.23 - CitiPower and Powercor Australia, *Information Security Business Case*, January 2015.

received outside of business hours would only be actioned the following business day. This creates a window for cyber security breaches to occur without an appropriate response.

Accordingly, we noted in our initial regulatory proposal that we were in the process of engaging an external service provider to monitor our security systems on a 24 hour basis.[407] We observed that an external service provider is a lower cost option and is expected to be more effective at identifying and responding to threats (compared to increasing our internal capacity).

AER's preliminary determination

In its preliminary determination, the AER declined to include a step change in its operating expenditure forecast for IT security monitoring.[408] The AER considered that our IT security monitoring is a discretionary business decision and that we have flexibility as to what monitoring we undertake and how much we spend on this area of operating expenditure. The AER considered that generally a service provider should be able to fund relatively small increases in discretionary operating expenditure without forecasting an increase in operating expenditure.

Our response to the AER's preliminary determination

As set out in appendix G of our regulatory proposal, the operation and maintenance of our distribution network is driven by three critical networks:[409]

- Supervisory Control and Data Acquisition (**SCADA**) – this network supports the collection of data from various facilities forming part of the distribution network, as well as sending certain control instructions;
- AMI – this network enables communication between our smart meters, and includes our AMI mesh, which is a wireless network designed to reduce communication faults at any single point of failure; and
- corporate IT network – this network supports our general business operations.

Security breaches to these IT systems have become a growing threat which requires a proactive IT security program to manage.

We proposed forecast capital expenditure for the 2016–2020 period for IT security measures designed to ensure the security of our network is maintained, proactively monitored and managed.[410] The AER forecast an alternative capital expenditure amount for those IT security projects in its preliminary determination.[411] To support those IT security measures, which include advanced technologies to alert if an attack or threat is genuine, it is necessary for a human to be available to interpret the security alerts and respond appropriately. Accordingly, we propose an operating expenditure step change for monitoring our IT networks on a 24 hour basis. As set out in the *CitiPower and Powercor Australia: Information security business case*, the ability to identify and detect security threats must be coupled with an ability to respond to system breaches.[412]

In appendix G of our regulatory proposal, we described how the prevalence and risk of cyber-attacks has increased, together with our exposure to cyber-attacks.[413] We also described how our ability to monitor, manage and mitigate the risk of cyber-attacks had recently improved.[414] In particular, we observed that:

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407 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, p. 179.

408 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-82.

409 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix G, pp. 8–9.

410 CitiPower, Regulatory Proposal 2016–2020, April 2015, appendix E, pp. 152–155.

411 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 6-103.

412 CP PUBLIC ATT 9.23 - CitiPower and Powercor Australia, *Information Security Business Case*, January 2015, p. 18.

413 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix G, pp. 10–11.

- it is only recently that our incumbent IT providers have begun to offer 24 hour monitoring services at competitive rates; and
- in late 2014, our security information and event management systems became operational. While the functionality of that infrastructure is still developing, it provides a framework that facilitates effective external monitoring, management and mitigation.

It is no longer prudent or efficient to only monitor our network during business hours. Instead, maintaining the safety, reliability and security of our distribution system and the quality, reliability and security of the supply of standard control services requires the ability to detect the attack, determine its methods and mitigate them to restore service, irrespective of when those attacks occur. The costs of 24 hour monitoring services are not reflected in our base year operating expenditure. Environmental changes in the IT security space are rapid and continual, but the costs of responding to these changes are discrete and lumpy. The advance of technology means that what may have been prudent and efficient in 2014 is not sufficient to manage risk in 2016 and beyond.

As set out in our regulatory proposal, engaging an external service provider is a lower cost option than expanding our internal IT security team, and is expected to be more effective at identifying and responding to threats.[415] We also considered further options, being do nothing or increase our IT capabilities through capital improvements (beyond that included in our IT capital expenditure forecast). We rejected the 'do nothing' option as it would not allow us to prudently manage the reliability, safety and security of our distribution system. IT capital expenditure alternatives were rejected on the basis that they would be more costly to consumers than the operating expenditure option of engaging an external service provider to monitor our IT security systems. Accordingly, we have now engaged an external service provider to monitor our IT security systems on a 24 hour basis.

This expenditure is necessary to maintain the safety, reliability and security of our distribution system through the supply of standard control services (clause 6.5.6(a)(3) and (4) of the Rules). While the AER suggests that we should be able to fund this expenditure without forecasting an increase in our base year operating expenditure, as the benchmarking analysis in the AER's preliminary determination reveals, at a total operating expenditure level we are in the top quartile of distributors.[416] As our costs are already efficient, the disallowance of material prudent and efficient cost increases above our base year expenditure, would result in an operating expenditure forecast that does not reflect efficient and prudent costs, or a realistic expectation of the cost inputs, required to achieve the operating expenditure objectives.

We categorise the exploitation of IT security issues as 'extreme'. For example, although the magnitude of a cyber-security incident may vary, an incident could have any or all of the following consequences:

- interruptions to the supply of power to customers;
- disclosure of sensitive material (including customer details), for example, attackers could publish customer and corporate information to public sites such as Reddit. This could include, name address, email address, phone numbers and electricity usage;
- serious injury or death to employees or contractors if the attackers change the state of the network while it is being worked on;

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414 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix G, p. 11.

415 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix G, pp. 11–12.

416 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-34.

- the disconnection/disablement of customers' meters (on a small or large scale);
- damage to company and customer property (and potentially the property of others) by changing the configuration of the power network via the SCADA system. Such a change could result in fires which could spread outside the customer and company premises;
- use of customer information as a basis for a database of identification material for the purposes of identity theft;
- damage to our reputation; and
- if the attack takes the form of a distributed denial of service which affects our dispatch and scheduling service, this could result in delays in responding to faults, poor customer service and customers without supply for extended periods of time. Should there be a major weather event at the same time, the consequences could be very serious.

Active, 24 hour monitoring of our IT systems enables us to better manage the risk of any or all of the above occurring.

The increased risks of a cyber security threat and its consequences are highlighted in Australian Government's Cyber Security Centre (**ACSC**) recent threat report entitled *Australian Cyber Security Centre 2015 Threat Report* (**ACSC Threat Report**). They are also highlighted by incidents at Sony Pictures, Target and the recent attack on the computers at the Australian Bureau of Meteorology. We discuss these matters below.

The recent ACSC Threat Report describes the threats networks of Australian organisations face from cyber espionage, cyber-attacks and cybercrime.[417] It notes that Australia's systems of national interest and critical infrastructure are vulnerable to malicious cyber activity. Significantly, in 2014 the top five non-government sectors assisted by the Computer Emergency Response Team Australia (**CERT Australia**) in relation to cyber security incidents were energy, banking and financial services, communications, defence, industry and transport.[418]

The following figures from the ACSC Threat Report set out:

- the number of incidents responded to by the Australian Signals Directorate (**ASD**) from 2011 to 2014. The figure on the left demonstrates that the number of incidents increased by approximately 260 per cent from 2011 to 2014;[419] and
- the number of incidents responded to by CERT Australia in 2014 which affected systems of national interest and critical infrastructure. The figure on the right demonstrates that the energy sector is the most likely target for cyber security threats.

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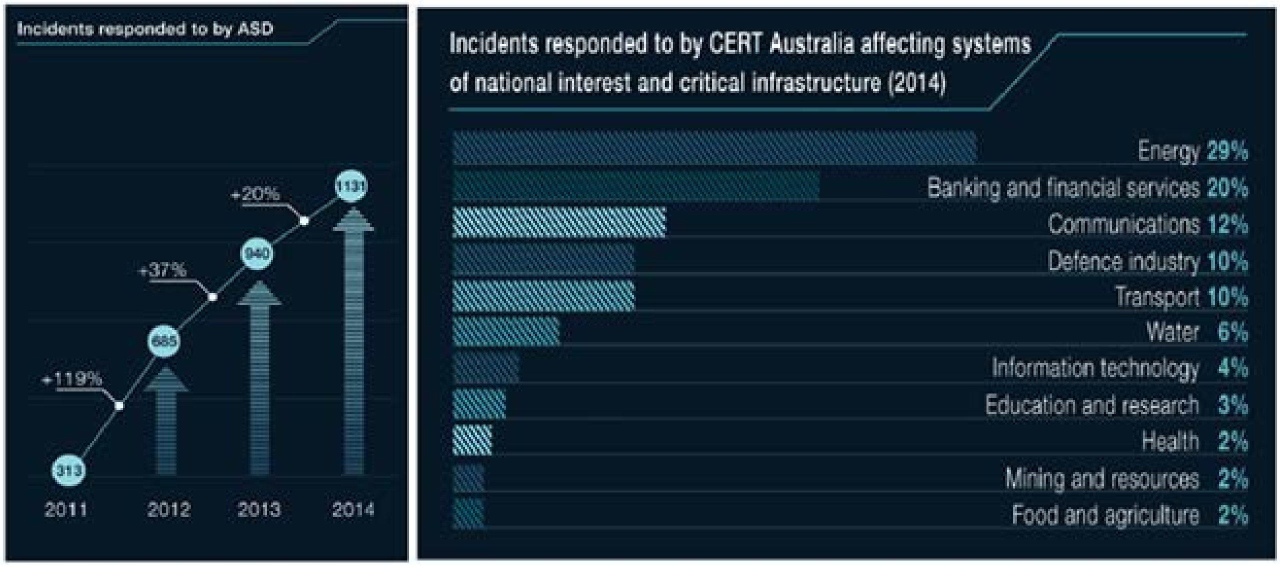
417 Australian Cyber Security Centre, *2015 Threat Report*, July 2015.

418 Australian Cyber Security Centre, *2015 Threat Report*, July 2015, p. 7. CERT Australia is primarily responsible for responding to cyber security incidents involving Australian Government networks and other networks of national importance.

419 Australian Cyber Security Centre, *2015 Threat Report*, July 2015, p. 7. Like CERT Australia, ASD is primarily responsible for responding to cyber security incidents involving Australian Government networks and other networks of national importance.

Figure 6.1 Cyber security incidents responded to by ASD 2011–2014 and incidents responded to by CERT Australia in 2014 affecting systems of national interest and critical infrastructure



Source: Australian Cyber Security Centre, *2015 Threat Report*, July 2015, figure 1, pp. 10 and 11.

The ACSC expects cyber security threats to increase globally in the near future. It predicts the following global trends to occur in the near future: [420]

- the number of state and cyber criminals with capability will increase;[421]
- due to the limited number of quality software developers, cybercrime-as-a-service is likely to increase, reducing the barriers for entry for cyber criminals;
- the sophistication of the current cyber adversaries will increase, making detection and response more difficult;
- spear phishing will continue to be popular with adversaries, and the use of watering-hole techniques will increase;[422]
- ransomware will continue to be prominent;[423]

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[420] Australian Cyber Security Centre, *2015 Threat Report*, July 2015, p. 24.

[421] The reference to state criminals in this sentence appears to be a reference to 'state-sponsored' criminals which is defined in the Australian Cyber Security Centre, *2015 Threat Report*, July 2015, p. 27 as '[a]n activity initiated and/or conducted by or for a foreign government body'.

[422] 'Spear Phishing' is defined in the Australian Cyber Security Centre, *2015 Threat Report*, July 2015, p.26 as '[a]lso referred to as socially-engineered emails, spear phishing emails are constructed to target specific people, often containing a hyperlink or an attachment which, when clicked on or opened, attempts to download malicious code to a workstation to enable a cyber adversary to conduct further malicious activities. The email is crafted to look like a legitimate email from a legitimate sender. Targeted communication (usually email) to members of an organisation as a group or as an individual in order to acquire sensitive information or infect with malware'. 'Watering-hole techniques' are defined on p. 27 as '[c]ompromise and placement of malware by cyber adversaries on a legitimate website frequented by their intended targets in an attempt to compromise the computers of visitors to the website'. 'Malware' is in turn defined on p. 26 as 'malicious software designed to facilitate unauthorised access to a system, or cause damage or disruption to a system'.

[423] 'Ransomware' is defined in the Australian Cyber Security Centre, *2015 Threat Report*, July 2015, p. 26 as '[e]xtortion through the use of malware that typically locks a computer's content and requires victims to pay a ransom to regain access. It can also be accompanied by a threat that the computer has been locked as a result of illegal or questionable conduct by the victim'.

- there will be an increase in the number of cyber adversaries with a destructive capability and, possibly, the number of incidents with a destructive element;[424] and
- there will be an increase in electronic graffiti, such as web defacements and social media hijacking, which is designed to grab a headline.

In response to the AER information request IR020 we provided a report by Gartner on the cyber security incident concerning Sony Pictures as an example of potential impacts.[425] That report notes the need for organisations to 'invest in forensic teams' to analyse the alerts from detection software.[426] A 24 hour monitoring service would serve a similar function.

Further, the *CitiPower and Powercor Australia: Information security business case* discusses the impact of a breach of Target's IT systems which resulted in approximately 40 million US citizens having their financial information stolen and a further 70 million having their personal data stolen. In particular, the business case observes that the attack on Target's IT system highlights the importance of ensuring not only the technologies, but also the people and processes are in place to administer information security in organisations.[427]

In addition, according to news reports there was a recent cyber attack on the Bureau of Meteorology's IT systems in response to which a classified report recommended the complete replacement of the Bureau's computer systems.[428] The Bureau of Meteorology is a critical national resource and also provides a gateway to other government agencies.

These attacks demonstrate that a prudent and efficient distributor would incur operating expenditure to ensure that its IT systems are actively monitored. Since this expenditure is not reflected in our base year operating expenditure, the AER should include a step change for this expenditure in our forecast operating expenditure for the 2016–2020 regulatory control period.

Consistent with our regulatory proposal, the forecast of our monitoring IT security step change is set out in the following table.[429]

Table 6.7 Monitoring IT security: annual step change ($ million, 2015)

Step change	2016	2017	2018	2019	2020	Total
Monitoring IT security	0.4	0.4	0.4	0.4	0.4	2.0

Source: CitiPower, *Regulatory Proposal 2016–20*, April 2015, appendix G, p. 13.
Notes: Totals may not add due to rounding.

424 'Cyber adversary' is defined in the Australian Cyber Security Centre, *2015 Threat Report*, July 2015, p. 25 as '[a]n individual or organisation (including an agency of a nation state) that conducts cyber espionage, crime or attack'.

425 CitiPower and Powercor, *AER information request - VIC EDPR - CitiPower - IR20 and VIC EDPR - Powercor - IR021*. Gartner, *Attack on Sony Pictures is a digital business game changer*, 9 February 2015.

426 Gartner, *Attack on Sony Pictures is a digital business game changer*, 9 February 2015, p. 4.

427 CP PUBLIC ATT 9.23 - CitiPower and Powercor Australia, *Information Security Business Case*, January 2015, p. 16.

428 ABC News report (online), *China blamed for massive cyber attack on Bureau of Meteorology computer*, 2 December 2015; ABC News report (online), *Classified report on Bureau of Meteorology cyber attack recommends computer system overhaul*, 3 December 2015.

429 As noted in our regulatory proposal, the costs associated with this step change have been split equally between Powercor and CitiPower. An equal split was applied as these costs are not driven by customer numbers.

6.4.6 Mobile devices

We maintain that the AER should accept our proposed step change for mobile devices as it is an efficient substitution of capital expenditure for operating expenditure and is necessary for our forecast operating expenditure to satisfy the operating expenditure criteria.

Initial regulatory proposal

In chapter 10 and appendix G of our regulatory proposal, we proposed a step change for moving to an operating expenditure only model for mobile devices. Our existing approach for accounting for mobile devices is a mixture of capital and operating expenditure. However, an internal review has indicated that moving to an operating expenditure only model will be more efficient.

AER's preliminary determination

In its preliminary determination, the AER declined to include a step change for mobile devices in its operating expenditure forecast.[430] The AER did not consider that there was sufficient evidence to demonstrate that our approach of moving from a mixture of capital and operating expenditure was an efficient trade-off.

The AER observed that in undertaking our cost benefit analysis of our existing practice with our proposed approach we assumed that we would incur the capital expenditure associated with replacing all of our phones and tablets every two years on the basis that this reflects the length of the maximum available warranty period from the manufacturer.[431]

The AER considered that the useful life of many phones and tablets will extend beyond the warranty. Accordingly, the AER considered that the assumption that it would be necessary to replace all smart devices every two years overstates the NPV of the capital expenditure that would likely be required in the next regulatory control period. As a result, the AER was not convinced that our proposed change in approach was efficient.

In addition, the AER considered that there were interactions between our proposed step change and our proposal to expense our corporate overheads in the 2016–2020 regulatory control period, such that our forecasting approach would overcompensate us for the prudent and efficient cost of leasing new mobile devices.

Our response to the AER's preliminary determination

We oppose the AER's decision to reject our proposed step change for mobile devices. We maintain that the AER should accept our proposed step change for mobile devices as it is an efficient substitution of capital expenditure for operating expenditure and is necessary for our forecast operating expenditure to satisfy the operating expenditure criteria.

The AER accepts in its preliminary determination that a step change to total operating expenditure may be required when a service provider chooses an operating solution to replace a capital one.[432] This is consistent with the statement in the AER's *Expenditure forecast assessment guideline* that '[i]f it is efficient to substitute capex with opex, a step change may be included for these costs (capex/opex trade-offs)'.[433] It is also consistent with the operating expenditure factors in clause 6.5.6(e)(6) and (7) of the Rules which require the AER to have regard to the relative prices of operating and capital inputs, and the substitution possibilities between operating and capital expenditure in determining whether it is satisfied that our proposed forecast operating expenditure reasonably reflects the operating expenditure criteria.

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430 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-82.

431 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-83.

432 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-78.

433 AER, *Expenditure forecast assessment guideline*, November 2013, p. 24.

However, the AER rejected our proposed step change on the basis that:

- it was not convinced that our proposed change in approach to mobile devices was efficient; and
- in any event, given the interactions between our proposed step change and proposed capitalisation of corporate overheads, our forecasting approach would overcompensate us for the prudent and efficient cost of leasing new mobile devices. [434]

For the reasons set out below, our proposal to move to an operating expenditure only model for mobile devices is efficient, and allowing the step change would not overcompensate us for the prudent and efficient cost of leasing new mobile devices.

The AER formed the view that we would be overcompensated if we were permitted a step change in operating expenditure for the cost of leasing new mobile devices on the basis that our capitalised corporate overheads included the cost of purchasing new mobile devices. As such the AER considered that our forecast operating expenditure would effectively include the cost associated with purchasing new mobile devices in 2014 (as an adjustment to our base year operating expenditure due to changes in our capitalisation policy) and the forecast cost of leasing new mobile devices (as a step change). In forming that conclusion the AER relied on our response to its information request No. IR007.

However, the AER has misinterpreted our response to the information request. In our response to the AER's information request No. IR007, we stated that the IT costs which drove an increase in corporate overheads from 2013 to 2014, included the following:[435]

- increase in iPads and iPhones;
- increase in data costs (more iPads, more data required to run them); and
- increase in telecommunication costs (more iPhones, more plans required to run them).

Our response should have specified that it was the increase in data and telecommunication costs associated with an increase in iPads and iPhones that contributed to increased corporate overheads (rather than overheads increasing due to the purchase of iPads and iPhones being included in corporate overheads). The purchase of iPads and iPhones was not included in our corporate overheads, but rather was included in our historical direct IT capital expenditure. Accordingly, contrary to the AER's preliminary determination, allowing our proposed step change would not overcompensate us for the prudent and efficient cost of leasing new mobile devices.

The AER was also not convinced that our proposed change in approach to mobile devices was efficient because the AER rejected our assumed two year replacement cycle for our mobile phones and tablets in our cost-benefit analysis. The AER does not provide any support for its position that it would not be prudent to replace all smart devices every two years and that the useful life of many phones and tablets will extend beyond the warranty. Accordingly, the AER does not appear to have any basis for its rejection of our proposed step change.

In September 2015, Gartner (a global IT research and advisory company) published a report which sets out its estimated primary useful life spans for various devices (including mobile phones and tablets) for the purpose of life cycle planning for financial decisions.[436] Gartner is a world leading global IT research and advisory company and we utilise Gartner's services and expertise to understand IT industry best practices, including obtaining impartial advice on product selection and industry trends. Gartner considers that in assessing the useful life of such devices it is necessary to have regard to the different needs of different users. Accordingly, Gartner

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[434] AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-84.

[435] CitiPower, *AER information request - VIC EDPR - CitiPower - IR007*, 3 July 2015, p. 1.

[436] Gartner, *Recommended life spans for mobile, PC and other endpoint-computing devices*, 11 September 2015.

estimates the useful life of the devices having regard to three different life span approaches, being aggressive, mainstream and cost constrained, to cover various endpoint strategies for different types of user profiles. Gartner describes those different approaches as follows:[437]

- an aggressive approach updates technology more frequently, either to attract employees or to meet demands from higher-paid executives to adopt the latest technologies and support critical applications. Examples of 'aggressive' users include those in C-suite, legal, medical, engineering and financial segments;
- a mainstream approach supports most knowledge workers. Examples of 'mainstream' workers include sales staff, government employees and administrative workers; and
- a cost-constrained approach often applies to organisations or users that engage in relatively stable repetitive tasks or in low-margin business. Examples of organisations that follow a cost-constrained approach include call centres, retail businesses and low-cost supply chain businesses.

The Gartner report sets out the following estimated primary useful life spans for smartphones and tablets for each of those user profiles:[438]

Table 6.8 Estimated primary useful life spans for mobile devices and tablets (years)

Device	Life-span (aggressive)	Life-span (mainstream)	Life-span (constrained)	Primary obsolescence factor	Secondary obsolescence factor
Tablets (i.e. slates)	2	3	3	Casing or screen breakage	Ability to support required software
Smartphones	2	2.5	3	Casing or screen breakage	Hardware failures

Source: Gartner, *Recommended life spans for mobile, PC and other endpoint-computing devices*, 11 September 2015, p. 5.

Having regard to the Gartner report, we consider that it is appropriate in our capital expenditure counterfactual for our field mobile phones and tablets to have a replacement cycle of two years and for our office mobile phones and tablets to have a replacement cycle of three years. Our field devices are used in a robust trade environment and are subject to a higher than normal risk of damage. Our office environment is more controlled and accordingly we expect there to be fewer cases of damage to office mobile devices and tablets. Both our office and field devices are, however, technically obsolete for business purposes after two to three years due to storage capacity and support requirements. For example, this is because:

- the features we typically include in development of new applications are typically supported by operating systems for up to 2–3 years;
- the processing power to make use of new and secure features typically requires a device less than 2–3 years old;
- the increased data storage requirements to hold and access greater amounts of data (particularly for field related applications) typically requires a device less than 2–3 years old; and
- the ability to make use of new hardware features in application development (e.g. fingerprint reader, 3D touch and screen resolution) requires devices less than 2–3 years old.

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[437] Gartner, *Recommended life spans for mobile, PC and other endpoint-computing devices*, 11 September 2015, pp. 3-4.

[438] Gartner, *Recommended life spans for mobile, PC and other endpoint-computing devices*, 11 September 2015, p 5.

The split of our field and office tablets is approximately 85 per cent field and 15 per cent office and the split of our field and office mobile phones is approximately 55 per cent field and 45 per cent office.

We have updated our cost-benefit analysis to reflect a two year replacement cycle for field mobile phones and tablets and a three year replacement cycle for office mobile phones and tablets. This change to reflect a three year replacement cycle for office mobile phones and tablets is supported by Gartner's report and is also responsive to the AER's comments that mobile devices may have a useful life beyond two years. Our analysis is set out in the model for the mobile devices step change attached to our revised regulatory proposal.[439]

After making these changes to our cost-benefit analysis, it remains the case that moving to an operating expenditure only model is a more efficient alternative than our existing approach. Accordingly, the AER should accept our proposed step change as an efficient substitution of operating expenditure for capital expenditure. If the AER rejects our proposed step change, it should include the capital expenditure forecast in our model for the mobile devices step change in our IT capital expenditure forecast.

The additional forecast operating expenditure following from our efficient substitution of operating expenditure for capital expenditure in respect of mobile devices is set out in the following table. We note that our forecast for this step change differs to that contained in our regulatory proposal because in determining our forecast for our revised regulatory proposal we applied the AER's output growth escalator in its preliminary determination (rather than that in our regulatory proposal) to our 2014 mobile device volumes to escalate those volumes for the 2016–2020 regulatory control period. We consider that it is appropriate to apply output growth in this manner in forecasting this step change as the number of mobile devices we require is likely to increase as the size of our network and quantity of services we supply increases. The modelling for this forecast is set out in the attached model, *Mobile devices step change*.

Table 6.9 Mobile devices: annual step change ($ million, 2015)

Step change	2016	2017	2018	2019	2020	Total
Mobile devices	0.4	0.1	0.4	0.2	0.4	**1.5**

Source: CitiPower
Notes: Totals may not add due to rounding

6.4.7 Decommissioning zone substations

We maintain that the AER should accept our proposed step change for decommissioning zone substations is necessary for our forecast operating expenditure to satisfy the operating expenditure criteria. In particular, the operating expenditure associated with the decommissioning of the five zone substations is necessary in order to maintain compliance with our regulatory obligations under the *Electricity Safety Act 1998* (Vic) and the *Environment Protection Act 1970* (Vic) (clause 6.5.6(a)(2) of the Rules). It is also necessary to maintain the safety, reliability and security of our distribution system through the supply of standard control services (clause 6.5.6(a)(3) and (4) of the Rules).

Initial regulatory proposal

In chapter 10 and appendix G of our regulatory proposal, we proposed a step change for costs associated with decommissioning five zone substations within our network (namely, the Spencer Street, Laurens Street, Tavistock

[439] CP PUBLIC RRP MOD 1.35 - CP Mobile Replacement Step Change.xlsx

Place, Prahran and Russell Place zone substations).[440] The costs include the removal of plant and equipment and the remediation of the sites.

AER's preliminary determination

The AER declined to include a step change for decommissioning zone substations in its operating expenditure forecast.[441] The AER observed that the fact that operating expenditure on projects and programs will change in the forecast period relative to the base year is not a reason to change its total operating expenditure forecast. The AER stated that changes in the mix of projects and programs to be undertaken can be accommodated by a service provider without changing the total funding a service provider requires; and it is not clear why we proposed a bottom up approach to forecasting this element of operating expenditure, but considers it reasonable to rely on a top down approach for most other elements of our proposal.

In addition, the AER noted that: [442]

- we have stated that the Prahran zone substation offload is driven by increasing numbers of developers requesting new connections, which is reducing spare capacity at the Prahran substation and we are proposing to permanently offload Prahran and remove most of the load to the Balaclava substation. Since the rate of change estimate already compensates a service provider for any incremental operating expenditure as a result of increased customer growth, it would be double counting to also allow an increase in operating expenditure for a step change; and
- since the AER has not forecast an increase in augmentation expenditure as a result of the proposed decommissioning of the West Melbourne Terminal Station (**WMTS**) 22kV sub-transmission network, it would be inconsistent with this position to include an operating expenditure step change relating to this project.

Our response to the AER's preliminary determination

The AER questions why we proposed a step change for the operating expenditure associated with decommissioning the five zone substations. We proposed a step change for decommissioning the Spencer Street, Laurens Street, Tavistock Place, Prahran and Russell Place zone substations because the forecast operating expenditure is not reflected in our base operating expenditure, nor is it reflected in the rate of change. However, the expenditure is necessary for our forecast operating expenditure to satisfy the operating expenditure criteria.

The operating expenditure forecasts are driven by three separate capital expenditure projects, being:

- the decommissioning of the WMTS 22kV sub-transmission network;
- the Prahran zone substation offload; and
- the Waratah Place zone substation development.

The operating expenditure associated with decommissioning the five zone substations includes the one off costs of removing and disposing of plant and equipment (including oil and asbestos), and remediating the sites.

The magnitude of the costs associated with decommissioning the five zone substations is material, and cannot be funded by other elements of our total operating expenditure allowance.[443] Due to prudent and holistic planning

440 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, pp. 180–181 and appendix G, pp. 17–22.

441 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-86.

442 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 7-86 to 7-87.

443 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix G, p. 21.

and network management, projects to decommission and remediate zone substation sites are extremely rare.[444] As such, the costs associated with such activities are not reflected in our base year operating expenditure. In particular, with respect to the decommissioning of the 22kV sub-transmission network from WMTS, there are no other examples of such a project being undertaken in a Victorian distribution network over the past 30 years.[445] It involves retiring an entire 22 kV network and upgrading and extending existing 66kV and 11 kV networks, and/or establishing new networks, without materially changing the level of installed transformation capacity.

Further, as the benchmarking analysis in the AER's preliminary determination reveals, at a total operating expenditure level we are in the top quartile of distributors.[446] As our costs are already efficient, the disallowance of material future prudent and efficient cost increases would result in an operating expenditure forecast that does not reflect efficient and prudent costs, or a realistic expectation of the cost inputs, required to achieve the operating expenditure objectives.

One of the reasons the AER rejected our proposed step change was because the rate of change estimate already compensated us for any incremental customer growth and accordingly, it would be double counting to also allow an increase in operating expenditure for a step change.[447] The AER formed this conclusion in response to our statement that the Prahran zone substation offload is driven by increasing numbers of developers requesting new connections, which is reducing spare capacity at the Prahran substation and that we were planning to permanently offload Prahran and move most of the load to the Balaclava substation. In making this statement, the AER has confused the basis for our step change. Our step change is for decommissioning costs and is not concerned with any increased operating and maintenance costs associated with customer growth which may be compensated for in the rate of change. Such decommissioning costs are not reflected in our base year operating expenditure.

A further reason the AER rejected our proposed step change was because allowing a step change would be inconsistent with its decision to reject our proposed augmentation expenditure for the proposed decommissioning of the WMTS 22kV sub-transmission network. For the reasons set out in chapter 7 of our revised regulatory proposal, we maintain that the augmentation expenditure for the decommissioning of the 22kV sub-transmission network should be allowed.[448] A cost benefit analysis encompassing synergies across distribution and transmission (having regard to AusNet Services' transmission asset replacement work at that terminal station) demonstrates that the proposed decommissioning of the WMTS 22kV sub-transmission network is the most economic option for maintaining safe and reliable electricity supply to customers served from that terminal station.[449] Further, given the unique nature of the work involved, the work cannot be considered to be business-as-usual replacement expenditure for the purpose of determining our capital expenditure allowance, therefore classifying the proposed expenditure as augmentation expenditure is the most appropriate approach. Accordingly, the AER should accept the associated operating expenditure for the

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444 In 2007–2008 we decommissioned an existing zone substation at Southbank. The demolition and decommissioning costs, however, were capitalised as the substation was immediately rebuilt.

445 CitiPower, *Updated business case and response to AER preliminary decision, decommissioning the 22 kV sub-transmission network from West Melbourne Terminal Station*, December 2015, p. 15.

446 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 7-34.

447 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 7-86 to 7-87.

448 See also, CitiPower, *Updated business case and response to AER preliminary determination, decommissioning the 22 kV sub-transmission network from West Melbourne Terminal Station*, December 2015.

449 CitiPower, *Updated business case and response to AER preliminary determination, decommissioning the 22 kV sub-transmission network from West Melbourne Terminal Station*, December 2015, p. 19. We note that the amount of operating expenditure attributed to the site remediation works in this business case does not include the full cost of our proposed step change because this business case only deals with the WMTS decommissioning works.

decommissioning of that network as it is necessary for our forecast operating expenditure to satisfy the operating expenditure criteria.

The operating expenditure associated with the decommissioning of the five zone substations is necessary in order to maintain compliance with our regulatory obligations under the *Electricity Safety Act 1998* (Vic) and the *Environment Protection Act 1970* (Vic) (clause 6.5.6(a)(2) of the Rules). It is also necessary to maintain the safety, reliability and security of our distribution system through the supply of standard control services (clause 6.5.6(a)(3) and (4) of the Rules). Since the costs associated with projects to decommission and remediate zone substation sites are not included in our base operating expenditure, it is necessary for us to be allowed a step change in forecast operating expenditure for the operating expenditure associated with the decommissioning of the five zone substations in order for our forecast operating expenditure to satisfy the operating expenditure criteria.

The decommissioning of the five zone substations is in accordance with the requirements of section 98 of the *Electricity Safety Act 1998* (Vic), which provides that:

> *A major electricity company must design, construct, operate, maintain and decommission its supply network to minimise as far as practicable—*
>
> *(a) the hazards and risks to the safety of any person arising from the supply network; and*
>
> *(b) the hazards and risks of damage to the property of any person arising from the supply network; and*
>
> *(c) the bushfire danger arising from the supply network.*

It is also in accordance with prudent asset management. Managing our network in this manner ensures that we maintain the safety, reliability and security of our distribution system, in addition to maintaining the quality and reliability and security of supply of standard control services (clause 6.5.6(a)(3) and (4) of the Rules).

As set out in appendix G of our regulatory proposal, each of the zone substations contains hazardous materials (including asbestos, oil and other contaminants).[450] The risks associated with hazardous materials are actively managed while a zone substation is in operation, however in the absence of a routine maintenance cycle these materials can become dispersed, with serious consequences, including:

- major health risks as a result of the dispersion of asbestos. As noted in our regulatory proposal, the potential risk associated with asbestos dispersion is heightened by the proximity of the zone substations to public facilities, such as the public housing buildings in Prahran;[451]
- potential environmental and fire hazard risks as a result of the dispersion of oil from oil-filled plant and equipment. As noted in our regulatory proposal, the *Environment Protection Act 1970* (Vic) makes it an offence to pollute land;[452] and
- electrocution risks as a result of exposed wires caused by the dispersion of plant and equipment. To mitigate this risk, the decommissioning process would seek to disconnect supply and remove exposed wiring and hazards. Utilities would also need to be disconnected.

Further, as outlined in our regulatory proposal, representatives of the City of Melbourne have outlined the significant public safety implications of unoccupied buildings (due to squatters and unauthorised access) in the City of Melbourne (with particular reference to the proposed decommissioning of the Laurens Street, Spencer

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[450] CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix G, pp. 19-21.

[451] CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix G, p. 20.

[452] *Environment Protection Act 1970* (Vic), section 45.

Street, Russell Place and Tavistock Place zone substations). In particular, those representatives referred to the risk of squatters or other unauthorised entrants attempting to remove equipment from the building, including any residual copper or other metal, including wiring and the risk of disturbing asbestos panels currently housing control and instrumentation equipment.[453] We note, in this regard, that the Rules require the AER to have regard to the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers identified in the course of our engagement with electricity consumers in assessing whether our operating expenditure forecast reasonably reflects the operating expenditure criteria.[454]

As provided in our regulatory proposal, our incremental forecast operating expenditure for the decommissioning of the five zone substations is set out in the following table. Our forecasting approach is set out in the model provided with our regulatory proposal, CP PUBLIC MOD 1.33 - *CP Decommissioning Step Change*.

Table 6.10 Decommissioning zone substations: annual step change ($ million, 2015)

Step change	2016	2017	2018	2019	2020	Total
Decommissioning zone substations	1.6	-0.1	2.8	2.6	-0.3	**6.7**

Source: CitiPower, *Regulatory Proposal 2016–2020*, April 2015, p. 22.
Notes: Totals may not add due to rounding.

6.4.8 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]

[453] CP PUBLIC ATT 10.11 - *Meeting between CitiPower and City of Melbourne, Minutes, Decommissioned zone substations*, 9 April 2015.

[454] NER, cl. 6.5.6(e)(5A).

[redacted]

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- [redacted]
- [redacted]

[redacted]

[redacted][457]

456 [redacted]

457 [redacted]

Table 6.11 [redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

6.4.9 Introduction of cost-reflective tariffs

In our revised regulatory proposal, we propose a new step change for operating expenditure related to the introduction of cost-reflective tariffs in Victoria.

On 27 November 2014, the AEMC made a rule which introduced new distribution network pricing arrangements into the Rules.[458] The purpose of the rule is to require network prices to reflect the efficient costs of providing network services to individual consumers so that they can make more informed decisions about their electricity usage.[459]

The rule sets out a new network pricing objective that the tariffs a distributor charges in its provision of direct control services to a retail customer should reflect the distributor's efficient costs of providing those services to that customer.[460] We are also required to develop a tariff structure statement (**TSS**) for approval by the AER as part of our five-year price reset process and to consult with consumers on its development.[461] Victorian distributors were required to submit their proposed TSS to the AER by 25 September 2015.[462] Prices based on the new pricing principles will apply in Victoria from 1 January 2017.

In determining our tariffs, we must comply with the following new pricing principles:

- each tariff must be based on the long run marginal cost of providing the service (clause 6.18.5(f) of the Rules);
- the revenue expected to be recovered from each network tariff must:
  - reflect our total efficient costs of serving the retail customers that are assigned to that tariff;
  - when summed with the revenue expected to be received from all other tariffs, permit us to recover the expected revenue for the relevant services in accordance with our distribution determination; and
  - in so doing, minimise distortions to the price signals for efficient usage of the network by customers (clause 6.18.5(g) of the Rules);
- we must consider the impact on retail customers of changes in tariffs from the previous regulatory year (clause 6.18.5(h) of the Rules);
- the structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to the type and nature of those retail customers and the information provided to and the consultation undertaken with those customers (clause 6.18.5(j) of the Rules); and

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458 AEMC, *National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014 No. 9*; AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014,* 27 November 2014.

459 AEMC, *Rule determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014,* 27 November 2014, p. (i).

460 NER, cl. 6.18.5(a).

461 NER, cl. 6.8.2 and 6.8.2(cla) as modified by clause 11.76.2.

462 NER, cl. 6.8.2(b) as modified by clause 11.76.2.

- a tariff must comply with the Rules and any pricing obligations imposed by the Victorian Government (clause 6.18.5(j) of the Rules).

The new rules also require us to:

- prepare a TSS with a regulatory proposal and revised regulatory proposal and provide an explanation of how the TSS meets the pricing principles for direct control services (clause 6.8.2(c) of the Rules);[463]
- include in the TSS the set of tariff classes, tariff structures, charging parameters for each proposed tariff, a description of how tariffs are set, and policies and procedures for assigning/reassigning customers to tariffs (clause 6.18.1A(a) of the Rules);
- accompany the TSS with an indicative pricing schedule setting out the indicative price levels for each tariff for each regulatory year of the regulatory control period (clause 6.18.1A(e) of the Rules);
- include in the regulatory proposal overview paper a description of how we engaged with retail customers and retailers in developing the proposed TSS and have sought to address any relevant concerns as a result of that engagement (clause 6.8.2(c1a) of the Rules);[464]
- include in our annual pricing proposal a demonstration of how each proposed tariff is consistent with the corresponding indicative pricing levels for the relevant regulatory year as set out in the indicative pricing schedule in the TSS or the previous year's annual pricing proposal, or an explanation of any material differences (clause 6.18.2(b7A) of the Rules); and
- include in our annual pricing proposal a revised indicative pricing schedule setting out for each tariff for each remaining year of the regulatory control period, the indicative price levels determined in accordance with our TSS (clause 6.18.2(d) of the Rules).

As required by the Rules, we submitted our first TSS to the AER on 25 September 2015.[465] Our TSS was developed following extensive customer engagement. The key difference between our existing and proposed network tariffs is the introduction of a demand charge for our residential and small and medium enterprise customers. We propose to introduce this charge gradually to enable customers to understand our proposed network tariffs and adapt their behaviour or implement solutions to help manage their electricity usage.[466] We introduced this charge because meeting maximum demand is a key driver of our network costs.[467] We consider that the introduction of a demand charge will encourage our residential and small and medium enterprise customers to manage their energy usage during particular periods thus lowering maximum demand, which will in turn reduce future infrastructure requirements and therefore lower future costs for all users.

At the time of submission of our regulatory proposal we had not sufficiently progressed our TSS to develop a sufficient understanding of the costs resulting from this change in regulatory obligation to enable us to develop a robust forecast of required operating expenditure. As we have now developed and submitted our TSS we have a clear understanding of the impact on our operating expenditure during 2016–2020 as a result of this change in regulatory obligation. This is consistent with the corresponding step change approved by the AER in its preliminary decision for Jemena.

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[463] Note, for the 2016–2020 regulatory control period, this obligation was modified to require us to submit the TSS to the AER by 25 September 2015 (clause 11.76.2 of the Rules).

[464] Note for the 2016–2020 regulatory control period, this obligation was modified to require us to provide this overview paper to the AER with the TSS (clause 11.72.2 of the Rules).

[465] CitiPower, *Tariff structure statement 2017–2020*, 25 September 2015.

[466] CitiPower, *Tariff structure statement 2017–2020*, 25 September 2015.

[467] CitiPower, *Tariff structure statement 2017–2020*, 25 September 2015.

As a result of this change in regulatory obligation or requirement, we expect that:

- during 2016 we will need to engage an additional project lead and an additional business analyst to manage and implement the process of transitioning customers to the new tariff structure;
- when we first introduce the tariff in 2017 we will have to undertake an initial mass market mail-out to help ensure our customers are aware of the introduction of the network tariff structure change;
- during 2017 we expect that there will also be a significant increase in customer enquiries and accordingly, we have included in our step change an estimate of the costs of responding to those enquiries (on the basis of our forecast volume of enquires and associated labour costs);
- during 2018 we propose to undertake a further mass market mail-out to further engage with our customers after the proposed tariffs have come into effect and as the demand component of the tariff increases; and
- we expect that from 2018–2020 we will have to continue to respond to customer enquiries regarding the new tariffs, however, at a lower volume than when they are first introduced. Accordingly, we have included in our step change an estimate of the costs of responding to those enquiries (on the basis of our forecast volume of enquires and associated labour costs).

Our forecasts in respect of customer enquiries are based on the customer enquiry volumes we received during the AMI rollout. We consider this is a reasonable basis for our forecast since both the AMI rollout and the new tariff charges represent complicated/technical issues that are likely to generate significant public interest and result in significant changes for our customers.

The forecast of our incremental operating expenditure costs associated with the introduction of cost-reflective tariffs is set out in the following table. The modelling for this forecast is set out in the attached model, *Introduction of cost-reflective tariffs step change*.

Table 6.12 Introduction of cost-reflective tariffs: annual step change ($ million, 2015)

Step change	2016	2017	2018	2019	2020	Total
Introduction of cost-reflective tariffs	0.1	0.7	0.5	0.5	0.5	**2.4**

Source: CitiPower

6.4.10 RIN compliance

We propose a new step change for operating expenditure required to comply with the AER's economic benchmarking and category analysis RINs in the 2016–2020 regulatory control period.

The basis for our step change is set out in our *RIN reporting compliance* business case attached to our revised regulatory proposal.[468] As described in that business case and in chapter 8 of our revised regulatory proposal, we have also proposed forecast capital expenditure associated with enhancing our IT systems to enable us to comply with our reporting obligations under the AER's economic benchmarking and category analysis RINs.

As noted in our business case, in order to comply with the RIN requirements, we must provide data that is complete, accurate, at a granular level and complies with the RIN definitions and format. However, the particular definitions and reporting requirements in the RIN do not correspond with the accounting principles we use in preparing our financial accounts, or our operational work delivery and reporting systems. This is because the

[468] CitiPower and Powercor, *RIN reporting compliance,* December 2015.

AER's reporting requirements are aimed at a different objective, being enabling analysis and comparison of multi-year data across distributors to drive efficient pricing outcomes for consumers.

To compound this problem our operating model includes the sharing between CitiPower and Powercor of business processes, systems, data and people to promote economy of scale efficiencies for customers. This efficiency is achieved by using common business processes that allocate costs via a cost allocation methodology. This existing operational process requires enhancement to enable actual versus estimated values to be reported to the AER for each of CitiPower and Powercor. In this regard we note that, subject to some exceptions, from the 2015 regulatory year we will be required to provide actual data (rather than estimated data) in response to the economic benchmarking RIN and from the 2016 regulatory year we will be required to provide actual data (rather than estimated data) in response to the category analysis RIN.[469]

As explained in our business case, following our initial experience in submitting the economic benchmarking and category analysis RINs in 2014, we undertook an assessment to determine the investment required to enable us to effectively and efficiently comply with the requirements of those RINs, including to enable the reporting of actual data. We determined that the best option is to enhance our existing operating model and system to build increased data, process, system and people capability to meet the current category analysis and economic benchmarking RIN requirements.

As set out in our business case, during the 2016–2020 regulatory control period we will have to incur additional operating expenditure above our base year operating expenditure on the following matters to support, maintain and sustain our RIN reporting solution:

- RIN governance – we will have to invest in improved data governance on a business wide level to ensure the ongoing effective stewardship of RIN related data. This expenditure involves the use of a data architect and governance manager, in addition to data analysts to work with the business to remediate identified quality issues. This data governance requirement is additional to the data governance already in place in our business and will require a more formalised and mature data performance and reporting regime to sustainably meet our ongoing RIN reporting requirements;
- data element maturity – following implementation of our overall solution, we propose to undertake an annual review of the business rules for each core reporting capability to ensure the rules are robust and reporting is accurate. This review will take into account all business-as-usual process and system changes to ensure that no inadvertent adverse impact has occurred to the RIN reporting integrity. We propose to complete these reviews prior to the commencement of the annual RIN reporting activity to ensure formal attestation and sign-off can be achieved in a timely manner; and
- increased audit requirement – as the AER is aware, certain information that we provide in response to the economic benchmarking and category analysis RINs is subject to independent audit or review.[470] We anticipate that we will have to incur increased audit costs due to the requirement to provide actual data. This is because of the higher level of assurance required under *Auditing Standard ASA 805 Special considerations - audits of single financial statements and specified elements, accounts or items of financial statement* for actual historical financial information when compared to the standard for estimated historical financial

[469] AER, *Final category analysis RIN for distribution network service providers*, March 2014, appendix E, paragraphs 1.3, 1.5 and 1.6; AER, *Economic benchmarking RIN for distribution network service providers*, November 2013; AER, *Better regulation, explanatory statement, regulatory information notices to collect information for economic benchmarking*, November 2013, p. 16.

[470] AER, *Final category analysis RIN for distribution network service providers*, March 2014, appendix C; AER, *Final economic benchmarking RIN for distribution network service providers*, November 2013, appendix D.

information, *ASRE 2405 review of historical financial information other than a financial report*.[471] As set out in our business case, estimated data is subject to 'review' which is a comparably lower level of assurance than an 'audit'. The AER has suggested that the definition of actual information in the economic benchmarking RIN requires information 'whose presentation is materially dependent on actual records' and that a sampling methodology would suffice to derive information in compliance with RIN requirements for actual information.[472] We have been informed by our auditors that data that includes inherent management estimates and judgments (such as that determined by such a sampling methodology) may result in considerable further audit effort as the auditor may need to complete additional complex procedures to reach a sufficient level of assurance over those estimates and judgments. The increase in audit effort will result in an increase in audit fees, given that audit fees are calculated as effort multiplied by an agreed audit rate card.

The forecast of our incremental operating expenditure costs associated with the RIN compliance step change is set out in the following table. The modelling for this forecast is set out in the attached model, *RIN compliance step change*.

Table 6.13 RIN compliance: annual step change ($ million, 2015)

Step change	2016	2017	2018	2019	2020	Total
RIN compliance	0.0	0.3	0.7	0.7	0.7	2.5

Source: CitiPower

6.4.11 Introduction of chapter 5A of the Rules

We propose a new step change for operating expenditure required to comply with chapter 5A of the Rules.

Chapter 5A is a component of the National Energy Customer Framework. It sets out the process and charging principles for connecting retail customers to the distribution network, including customers who are micro-embedded generators. Since the National Energy Customer Framework does not currently apply in Victoria, chapter 5A does not currently apply to us.

On 1 October 2015 we received a letter from the Victorian Minister for Energy and Resources informing us that the Victorian Government has decided to implement chapter 5A of the Rules in Victoria during the 2016–2020 regulatory control period.[473] The Victorian Government subsequently published the *National Electricity (Victoria) Further Amendment Bill 2015*, which amends the *National Electricity (Victoria) Act 2005* to apply chapter 5A of the Rules in Victoria.[474] The Minister for Energy and Resources stated in her second reading speech on the Bill that the purpose of the Bill is to 'enable connection to the electricity grid which is more transparent, timely and customer friendly'.[475] In this regard, the Minister noted that one of the barriers to the development of local renewable energy generation was the complexity of the current process to connect small-scale renewable energy generation to the electricity grid.

471 Auditing and Assurance Standards Board, *Auditing Standard ASA 805 Special considerations - audits of single financial statements and specified elements, accounts or items of financial statement,* October 2009; Auditing and Assurance Standards Board, *Standard on review engagements ASRE 2405 review of historical financial information other than a financial report*, August 2008.

472 AER, *Preliminary decision, Jemena distribution determination 2016–20*, October 2015, p. 7-79.

473 Minister for Energy and Resources, *Letter to CitiPower and Powercor regarding chapter 5A of the Rules*, 18 September 2015.

474 *National Electricity (Victoria) Further Amendment Bill 2015*; Explanatory Memorandum, *National Electricity (Victoria) Further Amendment Bill 2015.*

475 Minister for Energy and Resources, *Second reading, National Electricity (Victoria) Further Amendment Bill 2015*, 9 December 2015.

The Victorian Government has informed us that it intends that chapter 5A will apply in Victoria from no later than 1 January 2017.[476]

Chapter 5A of the Rules promotes transparency around customer connections by introducing the concept of 'offer and acceptance' by the connection applicant of the connection service. Our proposed step change is concerned with the change in regulatory requirements for basic connection services as a result of the implementation of chapter 5A of the Rules in Victoria. A basic connection service is defined in chapter 5A as:

> *means a connection service related to a connection (or a proposed connection) between a distribution system and a retail customer's premises (excluding a non-registered embedded generator's premises) in the following circumstances:*
>
> *(c) either:*
>
> *(1) the retail customer is typical of a significant class of retail customers who have sought, or are likely to seek, the service; or*
>
> *(2) the retail customer is, or proposes to become, a micro-embedded generator; and*
>
> *(d) the provision of the service involves minimal or no augmentation of the distribution network; and*
>
> *(e) a model standing offer has been approved by the AER for providing that service as a basic connection service.*

In respect of the process for a basic connection service, the application of chapter 5A in Victoria will mean that:

- we will be required to develop and submit for the AER's approval a proposed model standing offer to provide basic connection services for each class of basic connection services on specified terms and conditions covering the matters in clause 5A.B.2(b) of the Rules (clauses 5A.B.1 and 5A.B.2 of the Rules);
- we will be required to publish certain information on our website, including an application form for a new connection or a connection alteration, a description of how such an application should be made, a description of our basic connection services and the requirements for an expedited connection (clause 5A.D.1 of the Rules);
- connection applicants will be able to apply for an expedited connection service, which essentially means that the applicant accepts the model terms and conditions for the relevant basic connection service (clause 5A.F.3 of the Rules);
- where a connection applicant does not request an expedited connection service, the following processes will apply to a non-expedited connection service:
  - we are required to make a connection offer to the connection applicant within ten business days (or other agreed period) after receiving a properly completed application for the service and any additional information reasonably required under clause 5A.D.3(e) (clause 5A.F.1 of the Rules);
  - the connection offer remains open for acceptance for 45 business days from the date of the offer and, if not accepted within that period, lapses unless the period for acceptance is extended by agreement between the connection applicant and the distributor (clause 5A.F.2 of the Rules); and

[476] We note that section 2 of the *National Electricity (Victoria) Further Amendment Bill 2015* provides that the Act comes into operation on a day(s) to be proclaimed, however, where a provision of the Act does not come into operation before 1 January 2017, it comes into operation on that day. Accordingly, all provisions of the Act will apply from 1 January 2017, unless a provision(s) is subject to an earlier proclamation.

- if the connection offer is accepted, the terms and conditions of the connection offer become terms and conditions of a connection contract formed between the distributor and the connection applicant and are enforceable accordingly (clause 5A.F.5 of the Rules); and

- once the terms of the relevant connection contract have been agreed under either the expedited or non-expedited connection process, we are required to use our best endeavours to ensure that the connection work is carried out within the applicable time limits fixed by the connection contract (clause 5A.F.6). However, we are not obliged to commence or continue with the connection work if the connection applicant fails to comply with conditions that it is required to comply with.

In order to implement the new requirements in respect of basic connection services under chapter 5A of the Rules, we will be required to engage a project lead and a business analyst during 2016. In addition, to comply with the new requirements in respect of non-expedited connection services we will be required to undertake additional work throughout the 2016–2020 regulatory control period which is not reflected in our base year operating expenditure. Accordingly, our step change includes our forecast costs of dealing with non-expedited connection services (having regard to the estimated time it will take to deal with those enquiries and labour costs). We formulated this component of our forecast having regard to our forecast in our Reset RIN for basic connection services in each year of the 2016–2020 regulatory control period. We estimated that 10 per cent of connection services may be non-expedited and that it may take approximately 2 hours to deal with each application for a non-expedited service (including reviewing the application, responding to any enquires and making a connection offer). We note that the connection figures which we used in preparing our forecast do not include connection services for customers who are micro-embedded generators. Accordingly, we consider that our forecast is conservative.

The forecast of our incremental operating expenditure associated with the introduction of chapter 5A of the Rules step change is set out in the following table. The modelling for this forecast is set out in the attached model, *Chapter 5A step change*.

Table 6.14 Introduction of chapter 5A: annual step change ($ million, 2015)

Step change	2016	2017	2018	2019	2020	Total
Introduction of chapter 5A	0.1	0.1	0.1	0.1	0.1	**0.4**

Source: CitiPower

6.4.12 Changes to Electrical Safety (Electric Line Clearance) Regulations

In its preliminary determination, the AER indicated that we should address the net impact of the 2015 Electric Line Clearance Regulations in our revised regulatory proposal.[477]

The AER noted that it provided us with a positive step change in the 2011–2015 regulatory control period for the removal of structural branches exceptions for electric lines from the *Electricity Safety (Electric Line Clearance) Regulations 2010* (**2010 ELC Regulations**), which had been included in the previous *Electricity Safety (Electric Line Clearance) Regulations 2005* (**2005 ELC Regulations**). The AER suggested that since the 2015 ELC Regulations reintroduce exceptions for structural tree branches, it would expect a similar decrease in costs to the increase allowed for in the 2011–2015 regulatory control period.

In response to the AER's suggestion that the reintroduction of exceptions for structural branches (in isolation from other changes in the 2015 ELC Regulations) could decrease our vegetation management expenditure going

[477] AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-87.

forward relative to our base year vegetation management expenditure, we note that as discussed in the vegetation management attachment to our regulatory proposal:

- in 2011 and 2013, we received exemptions from Energy Safe Victoria (**ESV**) that permitted a transition to compliance with the 2010 ELC Regulations by 31 December 2014;[478] and
- as a result of community concern regarding the extent of tree pruning required to be undertaken to achieve and maintain compliance with the 2010 ELC Regulations, ESV engaged in discussions with us from late 2012 regarding permitting us to take advantage of exceptions to clearance requirements such as those contained in the 2005 ELC Regulations, and approved our Electric Line Clearance (Vegetation) Management Plan for 2014 to 2015 (**Vegetation Management Plan**) which set out modified clearance practices, including exceptions for structural tree branches.[479]

Our vegetation management expenditure during the 2016–2020 regulatory control period, therefore, will not decrease relative to base year vegetation management expenditure as a result of the reintroduction of exceptions for structural branches.[480] Further, having regard to our discussions with ESV, we consider that our existing practices and 2014 base year operating expenditure for vegetation management are reasonably consistent with the 2015 ELC Regulations as a whole.

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[478] ESV, *Letter from ESV to CitiPower attaching exemption under the Electricity Safety (Electric Line Clearance) Regulations 2010*, 18 February 2011; ESV, *Letter from ESV to CitiPower attaching updated exemption under the Electricity Safety (Electric Line Clearance) Regulations 2010*, 9 September 2013.

[479] The exemptions granted by ESV and our Vegetation Management Plan are described in the following attachment to our regulatory proposal: CP PUBLIC ATT 0.3 - CitiPower, *Vegetation Management Expenditure*, April 2015, pp. 5–7.

[480] This is confirmed by GHD's independent forecast of our prudent and efficient vegetation management expenditure for the 2016–2020 regulatory control period provided with our regulatory proposal which was prepared on the basis that we would maintain compliance over the 2016–2020 regulatory control period with the 2010 ELC Regulations as modified by our Vegetation Management Plan: CP PUBLIC ATT 0.3 - CitiPower, *Vegetation Management Expenditure*, April 2015, p. 15; CP PUBLIC ATT 0.2 - GHD, *CitiPower Forecast Expenditure for Vegetation Management*, March 2015.

6.4.13 Our revised regulatory proposal

The following table sets out our proposed step changes for the purposes of our revised regulatory proposal.

Table 6.15 Operating expenditure step changes for 2016–2020 ($ million, 2015)

Step change	Total
CIS and CRM system	1.3
Monitoring IT security	2.0
Mobile devices	1.5
Decommissioning zone substations	6.7
[redacted]	[redacted]
Introduction of cost-reflective tariffs	2.4
RIN compliance	2.5
Introduction of chapter 5A of the Rules	0.4
Total	**23.9**

Source: CitiPower

6.5 Our revised regulatory proposal

We provide the following summary of how in this revised regulatory proposal we have amended our regulatory proposal in respect of operating expenditure having regard to our response to the AER's preliminary determination described above.

We have amended our regulatory proposal and prepared this revised regulatory proposal to be consistent with the AER's preliminary determination in respect of the following:

- the AER's adjustment to base year operating expenditure due to changes in our capitalisation policy; [481]
- the AER's adjustment to base operating expenditure to remove operating expenditure incurred in 2014 on debt raising costs and the AER's forecast for debt raising costs over the 2016–2020 regulatory control period;[482]
- the AER's decision not to remove regulatory reset costs from base year operating expenditure;[483]
- the AER's decision not to adjust base year operating expenditure for our forecast defined benefit superannuation contributions;[484]
- the AER's decision to accept a proportion of our proposed step change in respect of our customer relationship management system;[485]

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481 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-42 to 7-45.

482 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-26 and 7-45.

483 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-78 to 7-79.

484 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-79 and 7-82.

485 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-74.

- the AER's decision to reject our proposed customer charter step change; and
- the AER's decision to reject our superannuation (accumulation members) step change.

Further, we have revised our regulatory proposal and prepared our revised regulatory proposal:

- to alter our forecast operating expenditure for GSL payments over the 2016–2020 regulatory control period;
- to alter our proposed overall rate of change as described above and in chapter 4 of our revised regulatory proposal;
- [redacted]
- to revise our proposed step change in respect of mobile devices;
- to propose an additional step change in respect of the introduction of cost-reflective tariffs through changes to the Rules;
- to propose an additional step change in respect of RIN compliance; and
- to propose an additional step change in respect of the Victorian Government's decision that chapter 5A of the Rules will apply to Victorian distributors.

For the avoidance of doubt, we maintain our original proposal set out in our regulatory proposal in respect of the following:

- our proposed adjustment to base year operating expenditure, accepted by the AER, to give effect to the reclassification of supply abolishment from alternative control services to standard control services;[486]
- our proposed adjustment to base year operating expenditure, accepted by the AER, due to the alignment of the accounting of certain replacement costs (being pole treatment costs, bird covers, fuses and surge diverters) to be consistent with the category analysis RIN;[487]
- our proposed adjustment to base year operating expenditure, accepted by the AER, to remove the DMIA;[488]
- our proposed adjustments to base year operating expenditure for movements in provisions, accepted by the AER;[489]
- our proposed adjustment to base year operating expenditure for the transfer of IT operating expenditure from metering to standard control services.
- our proposed step change in respect of decommissioning zone substations; and
- our proposed step change in respect of monitoring IT security.

Further, since we reject the AER's adjustment to base year operating expenditure to remove losses associated with the scrapping of assets, we have not made this adjustment in our revised regulatory proposal.[490]

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486 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, pp. 7-47.
487 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.
488 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.
489 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.
490 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-45.

The following table sets out our revised forecast operating expenditure for the 2016–2020 regulatory control period.

Table 6.16 Forecast annual operating expenditure ($ million, 2015)

Operating expenditure	2016	2017	2018	2019	2020	Total
Annual operating expenditure (2014)	58.3	58.3	58.3	58.3	58.3	**291.7**
Net base year adjustments	-0.1	-0.4	-0.4	-0.4	-0.4	**-1.8**
Change in capitalisation policy	17.7	17.7	17.7	17.7	17.7	**88.4**
Service reclassification	3.9	3.9	3.9	3.9	3.9	**19.5**
Step changes (excluding GSLs)	4.0	3.0	6.8	6.3	3.7	**23.9**
Rate of change	3.1	5.5	8.3	10.7	13.1	**40.7**
Total (excluding debt raising costs)	**87.0**	**88.0**	**94.6**	**96.5**	**96.3**	**462.4**
Debt raising costs	0.9	0.9	1.0	1.0	1.1	**5.0**
Total (including debt raising costs)	**87.9**	**88.9**	**95.6**	**97.6**	**97.4**	**467.3**

Source: CitiPower

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Capital expenditure – network 7

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7 Capital expenditure - network

This chapter sets out our comments on the AER's preliminary determination with respect to network capital expenditure, as well as our revised regulatory proposal.

The Australian Energy Regulator (**AER**) rejected our proposed gross capital expenditure of $995 million ($2015), and have included an alternative estimate of $720 million ($2015) in the preliminary determination. This 28 per cent cut reduces our gross capital expenditure to $136 million ($2015) below our actual expenditure in the 2011–2015 regulatory control period.[491]

This is a very disappointing preliminary determination, particularly when the AER's benchmarking shows that we are the top performer, or among the top performers, in all measures of capital expenditure in the National Electricity Market (**NEM**). It could be inferred that the AER is penalising those who are efficient, rather than rewarding top performers from its benchmarking.

The AER's preliminary determination reflects:

- rejection of our lower cost plan to augment our 11kV and 66kV networks to transfer load from our 22kV sub-transmission network, and de-commission that network, rather than undertaking like-for-like replacement on the 22kV networks served by West Melbourne Terminal Station (**WMTS**). The rejection was based on the AER's disagreement with our categorisation of this capital expenditure, which is not a legitimate basis for the AER to reject expenditure under the National Electricity Rules (**Rules**);
- rejection of our 'unmodelled' replacement capital expenditure that does not have an age profile, where the AER has ignored our detailed bottom-up build of expenditure required to meet our regulatory requirements and has instead substituted our forecast using our actual expenditure in the 2011–2015 regulatory control period. Our historical expenditure is understated as major delays to the Security of Supply project, for reasons beyond our control, in the Melbourne CBD during the 2011–2015 regulatory control period, has resulted in knock-on delays to other related replacement projects;
- an inappropriate reliance on the Australian Energy Market Operator's (**AEMO**) nascent forecasts for demand at the transmission connection point, which contain errors which the AEMO intends to correct alongside other methodological concerns after the AER's final determination in 2016; and
- gross capital expenditure for connections being understated.

A step up from history in our expenditure is required to meet expected demand and connect new customers, while safely deliver a quality and reliable electricity supply to our consumers. We must also meet new obligations to mitigate the risk of our assets contributing to starting a fire.

In our revised regulatory proposal, we propose $996.2 million ($2015) of gross capital expenditure. This reflects that we have:

- re-proposed our project to augment our 11kV and 66kV networks and de-commission our 22kV sub-transmission network served from WMTS, in collaboration with AusNet Services Transmission, as this solution is the least cost option to address the condition of the network and is in the long term interests of consumers;
- re-proposed our necessary 'unmodelled' replacement expenditure, highlighting why the expenditure is not reflected in our most recent historical expenditure;
- updated our plans for network augmentation to reflect our latest 2015 demand forecasts, resulting in a

491 Actual gross expenditure in the 2011–2015 regulatory control period is forecast to be $856 million ($2015, inclusive of overheads). Refer CP PUBLIC MOD 1.17 - *CP Capex Consolidation*.xlsx.

reduction in augmentation expenditure across a couple of sub-transmission lines; and

- corrected modelling errors relating to connections, but while we have accepted the AER's methodology for forecasting gross customer connections, we have corrected the methodology outlined by the AER for calculating customer contributions as well as taking account of the Victorian Government's planned introduction of Chapter 5A of the Rules; and
- accepted the AER's preliminary determination for our expenditure relating to new obligations arising from the Victorian Bushfires Royal Commission (**VBRC**).

The AER did not accept our proposed gross forecast capital expenditure in the preliminary determination, and instead used a substitute estimate that was approximately 28 per cent below our proposal. The largest reductions were in the categories of connections and augmentation, as shown in the table below.

Table 7.1 Total capital expenditure excluding equity raising costs ($ million, 2015)

Category	Regulatory Proposal	AER Preliminary Determination	Revised Proposal
Augmentation	203.3	119.0	201.6
Connections	332.1	236.2	330.0
Replacement	260.0	199.3	260.4
Non-network	104.0	88.1	106.0
Equity raising costs	2.3	1.9	4.9
Input escalation adjustment	-	-11.2	-
Gross direct capital expenditure	**901.8**	**633.3**	**902.8**
Plus direct overheads	93.5	86.5	93.4
Gross capital expenditure	**995.3**	**719.8**	**996.2**
Less capital contributions	144.9	58.8	170.4
Net capital expenditure	**850.4**	**660.9**	**825.8**

Source: CitiPower
Note: figures many not add due to rounding

In this revised proposal, we set out our comments on the AER's preliminary determination, and our basis for our revised regulatory proposal expenditure.

7.1 Rule requirements

Clauses 6.8.2(c)(2) and 6.5.7(a) of the Rules require us to submit a building block proposal for the total forecast capital expenditure for the 2016–2020 regulatory control period, that we consider is required in order to achieve the capital expenditure objectives.

The capital expenditure objectives are to:

1. meet or manage the expected demand for standard control services over that period;

2. comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
3. to the extent that there is no applicable regulatory obligation or requirement in relation to:
   (i) the quality, reliability or security of supply of standard control services; or
   (ii) the reliability or security of the distribution system through the supply of standard control services;

   to the relevant extent:

   (iii) maintain the quality, reliability and security of supply of standard control services; and
   (iv) maintain the reliability and security of the distribution system through the supply of standard control services; and
4. maintain the safety of the distribution system through the supply of standard control services.

The AER must accept the capital expenditure forecast that we include in our building block proposal if the AER is satisfied that the total of the forecast capital expenditure for the 2016–2020 regulatory control period reasonably reflects the capital expenditure criteria. That is, that the forecast capital expenditure reasonably reflects the efficient costs of achieving the capital expenditure objectives; the cost that a prudent operator would require to achieve the capital expenditure objectives; and a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

In making this assessment the AER must have regard to the capital expenditure factors which include (but are not limited to) benchmarking, historical performance as well as the extent to which the capital expenditure forecast includes expenditure to address the concerns of electricity consumers.

7.2 Replacement

Capital expenditure to replace assets in our network should enable us to continue to maintain the safety, security and reliability of the network, while minimising outages for customers. That is, the expenditure should allow us to 'keep the lights on'.

In this section, we set out our concerns with the AER's preliminary determination, and justify our expenditure set out in this revised regulatory proposal. Importantly:

- the AER did not accept our proposed replacement expenditure of $260 million ($2015), and have included an alternative estimate of $199 million ($2015) in the preliminary determination;
- the key difference between our regulatory proposal and the preliminary determination is that for unmodelled replacement expenditure, the AER has rejected forecast expenditure that is incremental to the amount spent during the 2011–2015 regulatory control period; and
- our revised regulatory proposal resubmits our proposed expenditure of $260 million for this category as the expenditure is necessary to maintain the safety, security and reliability of the network and meet our regulatory obligations.

7.2.1 Initial regulatory proposal

Our regulatory proposal set out that our forecast expenditure is driven by:

- completion of the refurbishment works intended to take place during the 2011–2015 regulatory control period, but which have been delayed as a result of delays to the upgrade of Brunswick Terminal Station (**BTS**);
- increasing replacement of poles and cross-arms and other key assets in line with an increasing defect rate;
- compliance with environmental regulations;

- replacement of protection relays based on condition; and
- replacement or refurbishment of large plant and equipment based on condition.

The regulatory proposal reflects our use of condition-based asset management methodologies. For high-volume plant and equipment, such as poles and wires, we use a reliability and safety based regime based on the principles of reliability-centred maintenance (**RCM**) together with regulatory obligations. It involves regular physical inspection of the assets, where defects are identified and a maintenance strategy to address the defect implemented. The asset management policies continue to evolve as the performance of the assets is monitored.

Major plant and equipment, such as zone substation transformers and switchgear, are managed using the internationally renowned condition based risk management (**CBRM**) asset management methodology. The systematic framework takes into account degradation, failure, performance and environmental factors to calculate the proposed year for the replacement of the asset. We then review the output in conjunction with other augmentation and development plans to identify opportunities for synergies, such that the replacement schedule can coincide with other major works.

A top-down check showed that our forecast expenditure was reasonable, as it allowed us to maintain the overall Health Index profile of assets managed using the CBRM methodology, including those with a Health Index of seven or above. That is, the top down check demonstrated that forecasts were reasonable, sustainable and enabled us to prudently and efficiently manage our ageing and deteriorating large assets.

The AER's replacement expenditure (**repex**) model was also used to cross-check the reasonableness of our forecasts. The repex model is a high-level probability based model that forecasts replacement for various asset categories based on their condition (using age as a proxy) and unit costs, but has recognised major limitations. That said, for the elements of replacement expenditure where the cost drivers are covered by the repex model, our forecasts were lower than the AER's repex model.

7.2.2 AER’s preliminary determination

The AER did not accept our proposed replacement expenditure of $260 million ($2015). The AER instead included an alternative estimate of $199 million ($2015), excluding overheads. This is 77 per cent of the amount that we proposed.

Essentially, the AER accepted our forecasts for expenditure categories that are covered by the repex model, but substituted the amounts outside of the repex model, with our actual unmodelled replacement expenditure in the 2011–2015 regulatory control period.

The AER used a range of assessment techniques to assess our replacement expenditure forecasts, including:

- analysis of our long term total repex trends, in which the AER noted that our forecast to underspend the regulatory allowance for replacement in the 2011–2015 regulatory control period can be attributed to the impact of delays to the upgrade of BTS and strategies to align replacement and augmentation projects, but acknowledged limitations in long term year on year comparisons of expenditure;
- use of the calibrated repex model for six categories of expenditure;
- technical review by Energeia to review whether our forecast expenditure will allow us to prudently and efficiently maintain the safety and reliability of the network; and
- consideration of network health indicators and comparative performance metrics, which the AER noted have not been used in rejecting our forecast expenditure but suggests that outages have been stable, residual asset lives have remained flat and asset utilisation has reduced over different historical periods.

Calibrated repex model

The AER used the repex model to forecast poles, overhead conductors, underground cables, service lines, transformers and switchgear. Using our age profile for each asset category, the AER calculated the volume of assets to be replaced using assumptions around asset lives. The AER considered that our technical asset lives are much shorter than the actual lives of assets in the network. Therefore, the AER calculated a calibrated asset life by taking into account our past five years of replacement volumes and the current asset age profile. The calibrated asset life scenario was thus used to forecast replacement volumes.

The calibrated repex volumes were multiplied by unit costs to estimate the replacement expenditure required for the next period. The AER modelled two scenarios using:

- our historical unit costs reflecting the costs that we have has incurred over the last five years; and
- our own forecast unit costs.

The AER found that our proposed replacement expenditure of $131 million ($2015) for these six categories was very close to the estimate predicted using our historical unit costs, and far below the expenditure using forecast unit costs. On this basis, the AER concluded that our forecast is likely to be a reasonable estimate of business as usual replacement expenditure.

Predictive modelling of other categories

The AER has accepted our forecast expenditure for pole top structures, on the basis that the proposed expenditure is lower than our replacement expenditure in this category during the 2011–2015 regulatory control period.

The AER also accepted our forecast expenditure for SCADA. The AER noted that our proposed expenditure is a modest increase compared to actual expenditure in the 2011–2015 regulatory control period, but that we have provided supporting information that demonstrates the need for greater volume replacement of these assets.[492]

However, the AER rejected our proposed expenditure for unmodelled replacement expenditure. As the proposed expenditure was above our historical expenditure, the AER reviewed the supporting material provided by CitiPower to assess whether the step-up is justified. The AER:

- acknowledged that there are limited historical examples of the type of expenditure identified by CitiPower;
- acknowledged that some non-recurrent replacement may occur;
- considered the step-up from history does not accord with the increases in expenditure for the replacement categories of expenditure contained in the repex model and for pole top structures;
- noted that some of the unmodelled expenditure could be included in the repex model, such as replacement of transformers to address noise pollution; and
- were of the view that the options set out in the business cases to address the potential network risks were not sufficiently considered, and thus the cost–benefit analysis did not establish that the least cost option had been selected.

On the basis of the above, the AER rejected our proposed expenditure of $88 million ($2015), and substituted it using our historical expenditure of $28 million ($2015) for this category.

[492] AER, *Preliminary Decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-83.

7.2.3 Our response to the AER's preliminary determination

We disagree with the AER's approach to rejecting our unmodelled replacement capital expenditure. This category reflects necessary works that we must undertake in the 2016–2020 regulatory control period, in addition to those projects delayed by the upgrade to the Brunswick Terminal Station (**BTS**). In this section we explain that:

- historical expenditure is understated and that our forecast expenditure would be consistent with history if not for the BTS delays;
- replacement of the building to house the Waratah Place (**WP**) zone substation is underway and is necessary to enable us to complete the CBD Security of Supply project;
- the Russell Place (**RP**) zone substation building is past its end-of-life but is still in service to deliver synergies with the WP zone substation project, prior to its planned decommissioning in 2018, however failure to rectify structural defects in the building will result in ongoing safety risks to the public;
- the redevelopment of the Brunswick (**C**) zone substation is overdue as it was impacted by the delays to the upgrade of BTS, and the costs of the civil building and secondary system works must also be approved by the AER for consistency of its decision making with other elements of the project;
- the construction of a 51 storey residential tower next to our Montague Street (**MG**) zone substation will require us to replace the noisy transformers so that we can comply with noise regulations;
- remediation of our CBD underground pits and green pillar boxes is necessary to reduce the safety risk to the community; and
- we have no alternative but to comply with the request from Yarra Valley Water to remove our cross-arms from their assets, and such works have no historical precedent in our network.

These issues are discussed in turn below.

Overall, we do not consider that the AER's substitute estimate of capital expenditure for replacement is consistent with the capital expenditure objectives in the Rules. In particular, we do not consider that it will enable us to:

- comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
- maintain the reliability of the distribution system through the supply of standard control services; or
- maintain the safety of the distribution system through the supply of standard control services.

In particular, the exclusion of necessary replacement expenditure that does not fit into the AER's repex model will not allow us to complete works that are necessary for the CBD Security of Supply project that is required by the Victorian Electricity Distribution Code, maintain the reliability of the network through the refurbishment or replacement of aged zone substations, or maintain the safety of the network to the general public through the rectification of the RP zone substation and replacement of underground pits in the Melbourne CBD in accordance with the *Electricity Safety Act 1998* (Vic).

Corrected view of historical expenditure on unmodelled replacements

As noted above, some of our planned expenditure on assets that are either not replaced by age, or are not defined by a detailed asset age profile, was deferred from the 2011–2015 regulatory control period as a result of matters beyond our control. In particular, community and local government objections to AusNet Service's planning permit for the upgrade of BTS resulted in delays to the CBD Security Upgrade and Metro projects, and knock-on delays to the refurbishment of the C zone substation.

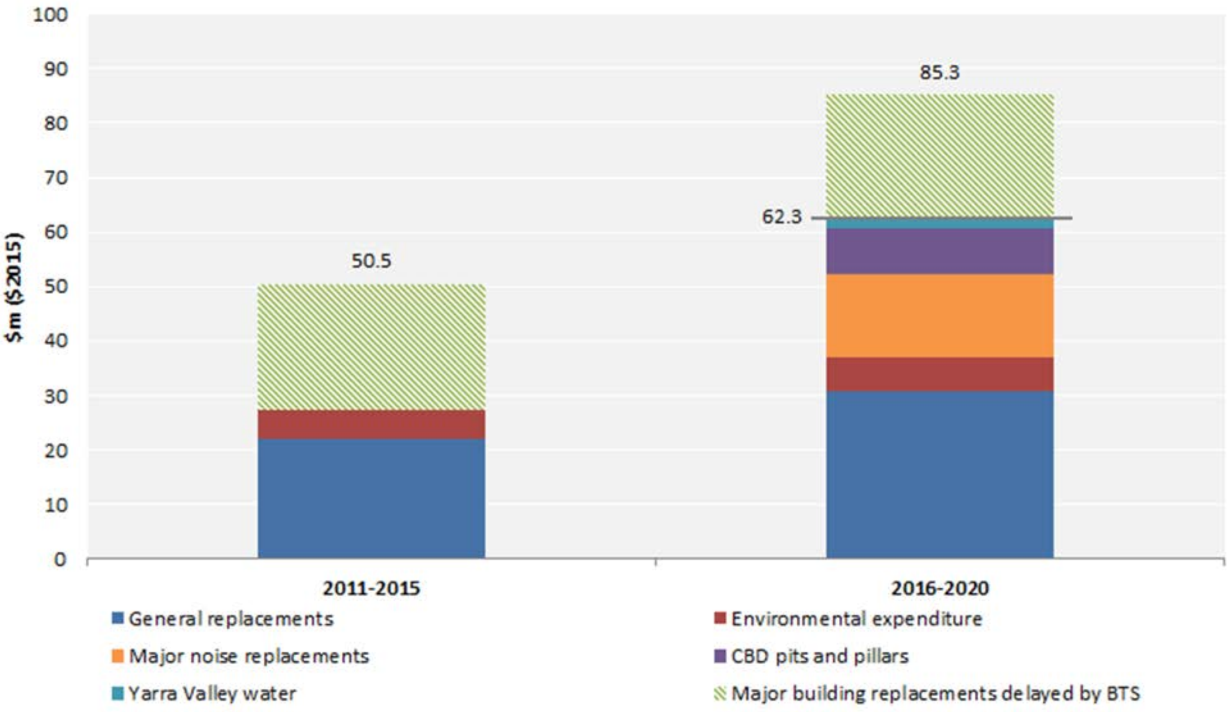
First, the switching substation in Waratah Place, referred to as W, is in a deteriorating building. As the station is being upgraded to a new zone substation (**WP**), CitiPower intended to demolish the existing building and rebuild. The rebuild is necessary for the new facility to be capable of safely and securely housing new 66kV switchgear so that it can switch load between Richmond Terminal Station (**RTS**) and BTS at 66kV. This project was delayed as a result of the delays to the upgrade of BTS to 66kV, but is now underway.

Secondly, the ageing assets and building at Russell Place (**RP**) zone substation were intended to be replaced. However, we determined that it would be more cost effective to transfer the entire load to the new WP zone substation and then decommission RP. These works were also impacted by the BTS delays.

Thirdly, the delay to the upgrade of BTS impacted the timing of the refurbishment of the Brunswick (**C**) zone substation. The C zone substation is served by 22kV sub-transmission lines from BTS 22. As part of the refurbishment, we intended to upgrade the zone substation to 66kV, given the long term strategy to replace the ageing 22kV sub-transmission network with the 66kV sub-transmission network. However given the delay to the establishment of BTS66, we could only connect the upgraded C zone substation to BTS when it is upgraded to 66kV. The BTS delay therefore delayed this project.

All of these projects relate to expenditure on building replacements. Should they have occurred, as planned, during the 2011–2015 regulatory control period, then we would have spent \$50 million (\$2015) on unmodelled replacement expenditure. This is shown in the figure below.

Figure 7.1 Historical and forecast expenditure without impact of BTS delays (\$ million, 2015, direct)



Source: CitiPower

If these projects had been completed, then we would only be requesting \$62.3 million (\$2015) of unmodelled replacement expenditure for the 2016–2020 regulatory control period. This would therefore be only a small step-up from historical expenditure.

Waratah Place zone substation building is required to comply with our CBD Security of Supply obligations

The switching substation in Waratah Place, referred to as W, is in a deteriorating building. The site needs to be upgraded to a new zone substation (**WP**) to also house seven Gas Insulated Switchgear (**GIS**) circuit breakers to enable the ability to switch our load between RTS66 and BTS66, in addition to two 60MVA transformers.

While our CBD sub-transmission network can withstand the loss of one network element without the loss of supply (**N-1**), the switching functionality is necessary to ensure that our network can be re-configured to withstand the further loss of another element in the 66kV sub-transmission network more than 30 minutes after the loss of the first element (**N-1 Secure**). Therefore, the switching station is a key component of the CBD Security of Supply project, which must be completed to enable us to comply with clause 3.1A of the Victorian *Electricity Distribution Code*.

Rejection of expenditure to demolish and rebuild the site is inconsistent with the AER's approval of related expenditure. In particular, the AER has approved the expenditure associated with the transformers and circuit breakers in the augmentation category. In respect of that expenditure, the AER noted:[493]

> *We are satisfied that the scope and timing of regulatory proposal accords with the CBD Security of supply upgrade plan's scope and timing of work. Because the upgrade sets out prescribed capital works, we consider that there are no reasonably alternative prudent options other than undertaking the work set out in the plan.*

The current building was constructed in around 1935 and does not comply with current design standards (e.g. earthquake standard) or our Health and Safety policies. It requires extensive strengthening works, particularly to house the transformers which weigh around 160 tonnes.[494]

The building will house assets that have a 49 year asset life. The existing building will not remain serviceable for that period of time without significant refurbishment works, given the extent of deterioration from the water ingress over many years into the steel columns, beams and slab reinforcement. The longevity of the existing brick structure is indeterminate.[495] Any refurbishment works could impact our reliability of supply from this key site.

The replacement of the building is a unique project that is necessary to allow our completion of the CBD Security of Supply project. Our costs for the building construction are efficient and prudent, and reflect our contracts with the construction companies that are currently undertaking this essential work.

Jacobs has reviewed our business case and supporting information for this project. Given that we did not incur such expenditure in the previous 2011–2015 regulatory control period, they found that the AER's use of historical trend analysis to assess unmodelled replacement expenditure was inappropriate. [496] Jacobs also highlighted the illogicality of the AER approach, given the AER's comments that there are limited historical examples of expenditure of the type identified by CitiPower, and acknowledgement that some non-recurrent replacement may occur.

Jacobs found that this project is an integral element of the W switching station project, and considered our expenditure to be efficient and prudent and necessary for compliance with the Victorian *Electricity Distribution Code*.[497]

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493 AER, *Preliminary Decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-48.

494 Aurecon, *Building Study Report Waratah Place (W) Zone Substation*, 13 January 2011, p. 1.

495 Aurecon, *Building Study Report Waratah Place (W) Zone Substation*, 13 January 2011, p. 1

496 Jacobs, *CitiPower Proposed 2016-20 Repex Other*, 15 December 2015, p. 8.

497 Jacobs, *CitiPower Proposed 2016-20 Repex Other*, 15 December 2015, pp. 6–10.

This project is underway with early demolition-related works already completed. The AER must approve this forecast expenditure as it is necessary to enable us to comply with our regulatory obligations, and reasonably reflects the efficient costs of achieving the capital expenditure objectives.

Russell Place building is in very poor condition

The WP zone substation will take the entire load from the Russell Place (**RP**) zone substation. RP, which is an underground zone substation, will then be decommissioned. However, defects in the building structure need to be rectified to minimise public safety hazards.

The RP building and assets are in poor condition. We intended to replace the assets, however through the identification of synergies with the CBD Security of Supply project assessed that it would be more cost effective to decommission the zone substation. To allow these synergies to be realised, we undertook works in the 2011–2015 regulatory control period to reinforce the building. This involved building more supports into the basement so that the building could withstand the weight of the GIS equipment.

While we plan to decommission the zone substation, we still need to ensure that it is structurally sound for the tenants occupying the building above the ground. Building reports from structural engineers have identified that there is corrosion in the retaining walls of the building, which pose safety issues to the public.

The rectification of the RP building is necessary for us to comply with all application regulatory obligations. In particular we must comply with section 98 of the *Electricity Safety Act 1998* (Vic) which requires us to design, construct, operate, maintain and decommission the supply network to minimise as far as practicable the hazards and risk to the safety of any person or damage to the property of any person, arising from the supply network.

Redevelopment of Brunswick zone substation is overdue

We intended to upgrade the Brunswick (**C**) zone substation in the 2011–2015 regulatory control period, however this project was delayed as a result of delays to the upgrade of BTS to 66kV. We need to upgrade the building that houses our assets.

We did not upgrade any other zone substations during the 2011–2015 regulatory control period. The previous redevelopment related to the Southbank (**SB**) zone substation which was completed in 2009/10. We only have around 42 zone substations, so major redevelopments do not occur every five years particularly given our strategy to decommission several of our oldest zone substations.

The C zone substation is currently served by 22kV sub-transmission cables from BTS that were installed in approximately 1940 and are in poor condition. One of the cables has a fault and is out-of-service. The zone substation itself has ageing assets and associated network equipment which is in poor condition, including:

- four fixed-tap 22kV/6.6kV transformers with high Health Indices;
- aged switchgear that has manual-spring rewinds that do not support the current service standard and creates workplace hazards; and
- aged switchboard in poor condition.

The AER has approved our replacement expenditure for the transformers and switchgear, which it assessed using the repex model.

However, the AER has not approved the costs associated with the substation civil building, switchyard cabling and associated secondary system work. These works do not have an age profile, and thus sit outside of the repex model. They include:

- 66kV and 11kV cable works in the yard;

- civil works in the yard which will include fire segregation, bunding and oil containment/ separation equipment;
- installation costs including associated protection and control equipment and wiring; and
- major building augmentation.

Jacobs has reviewed our business case and supporting information for this project. They found that the AER's reliance on the expenditure trend in the 2011–2015 regulatory control period to be unreasonable, given that the AER recognised there are limited historical examples of such expenditure for CitiPower.[498]

Furthermore, Jacobs has assessed the costs of the redevelopment of the C zone substation against our similar Bouverie/Queensberry (**BQ**) zone substation project, which was predominately completed in the 2006–2010 regulatory control period. Jacobs found that the budget allocation for the C zone substation redevelopment project is appropriate.[499]

For consistency of decision making, we seek the AER to approve our civil expenditure associated with the redevelopment of the C zone substation. This forecast expenditure meets the capital expenditure objectives as it allows us to maintain the reliability and safety of the network through the refurbishment of an aged zone substation.

Need to comply with noise standards

Our Montague (**MG**) zone substation at 84-96 Johnston Street, South Melbourne has noisy transformers. They are not currently a problem, given that the zone substation is located in an industrial area.

However, following the 2012 rezoning of the Fishermans Bend area to Capital City Zone and subsequent planning permit approval for the construction of four residential apartment towers of up to 51 storey's next door, future residents will be subject to noise levels exceeding the night time noise limit set under the *State Environment Protection Policy (Control of Noise from Commerce, Industry and Trade) No. N-1* (commonly referred to as SEPP N-1).[500] The following picture shows the extent of these residential towers.

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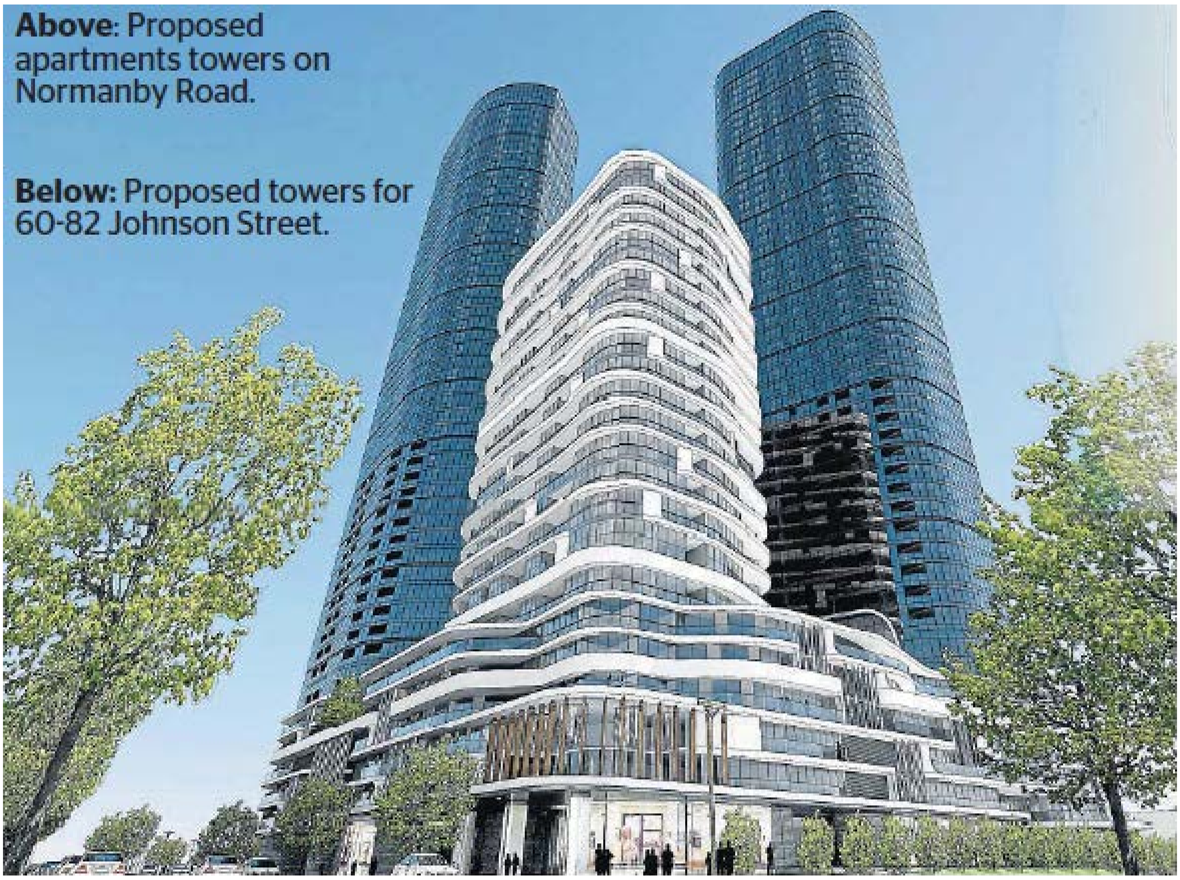
498 Jacobs, *CitiPower Proposed 2016-20 Repex Other*, 15 December 2015, p 14.

499 Jacobs, *CitiPower Proposed 2016-20 Repex Other*, 15 December 2015, p. 16.

500 Minister for Planning, *Planning Permit for 60-82 Johnson Street, South Melbourne*, 21 May 2015; and WatsonMossGrowcott, *Noise Emission Assessment*, May 2013.

Figure 7.2 Proposed towers next door to our zone substation



Source: The Age, *Fishermans Bend plan 'misguided'*, 20 October 2015, p. 8.

The least cost solution is to replace those transformers. This is a unique solution.

CitiPower only has around 106 zone substation transformers, and noise concerns are confined to very few of the transformers. Historically, we have used other solutions to address any concerns relating to noise emitted by the transformers, including:

- internal lining of the walls at Bouverie St/ Queensberry St (**BSBQ**) zone substation, installation of noise absorbing wall panels at Toorak zone substation, at a total cost of around $300,000 (nominal) during the 2011–2015 regulatory control period;
- relining the walls of the Prahran (**PR**) zone substation during the 2006–2010 regulatory control period; and
- enclosure of part of the Fitzroy (**F**) zone substation during the 2006–2010 regulatory control period.

These solutions are not available to us as the zone substation is not currently enclosed, and the costs for enclosure are likely to be substantial given the need to offload the site to allow the building works to take place. As this is a leased site, not only would any capital works require landlord and council approval, we may also need to 'make good' and remove these works at the end of the lease.

Consequently, replacement of transformers for breaching noise requirements is not 'business as usual' replacement, and therefore is not reflected in historical volumes.

We further note that we did not include the replacement of these transformers in our expenditure build-up for 'business as usual' replacements that the AER assessed using the repex model. In that category, our expenditure reflected our forecast requirements for replacing transformers based on condition under the CBRM process. The three transformers at MG have mid-level Health Indices, with an expected remaining life of 25 years, and thus are not in sufficiently poor condition to trigger replacement under that assessment process.

Our updated business case confirms that the replacement of three transformers at MG is the lowest cost option to enable us to comply with the noise regulations when they start to apply.[501] The AER must approve this forecast expenditure as it is necessary to enable us to comply with our regulatory obligations, and reasonably reflects the efficient costs of achieving the capital expenditure objectives.

CBD pits and pillars must be replaced for safety reasons

We have approximately 1,000 regular cable pits in the CBD, with about half located in the roadways and footpaths. Incidental inspection of the cable pits, while undertaking cable replacement works, has revealed significant deterioration and corrosion that poses a safety risk to the public.

In particular, the inspections have identified CBD pits that were considered to be mid-life have suffered from water ingress through the conduit system. As a result, the steel supports for these pits are rusted and corroding, and the concrete is spalling. The roadway pits are exposed to high levels of vibration and tonnage, particularly from trams.

The condition of our pits means that they are susceptible to failure, such as a collapse of the pit roof or collapse of the pit covers at the surface opening. This could result in serious injury to the public and CitiPower personnel.

Therefore, we must remediate the highest risk pits found to be defective by inspection over the next five years.

Figure 7.3 Pictures of CBD underground pit from above and inside; and cast iron pillar

Source: CitiPower

We also have around 800 low voltage pillars in the CBD, of which around 100 are the green cast iron variety that were installed by the Melbourne City Council prior to World War II. The predominant risk with pillars is electrical contact to personnel and the public, who intentionally or otherwise open the box and touch our equipment. Maintenance has historically been carried out reactively, following reports from the public, employees or contractors.

The security of these boxes needs to be improved and rectified to maintain the safety of our network.

Jacobs considers that the forecast expenditure for pit and pillar replacement belongs in the unmodelled replacement category, as these assets have been managed without specific programs of inspections or remediation typical for long life assets. As such, insufficient expenditure has been incurred in the previous

501 CitiPower, *Material Project — Environmental Noise program - MG updated*, December 2015.

regulatory cycle to undertake informed trend analysis or include an appropriate condition profile in the AER's repex model.[502]

Importantly, Jacobs finds that there are strong and compelling requirements to undertake replacement works for pits and pillars.[503] The AER must approve this proposed expenditure which is necessary to maintain the safety of our network in the provision of standard control services, and for compliance with our obligations in the *Electricity Safety Act 1998* (Vic). That is, the expenditure is consistent and necessary for the achievement of the capital expenditure objectives.

Yarra Valley Water case is unique

We have a small number of cross arms that are affixed to the drain waste vent system owned by Yarra Valley Water. We have been requested to remove our cross arms from their assets for operational safety reasons.

Jacobs noted that as the expenditure is not a controllable expense and has not been previously incurred, then it should be considered in the unmodelled replacement category. Therefore, this small project represents a step up from our historical replacement expenditure so that our assets are appropriately located.

Our expenditure was reviewed by Jacobs and found to be efficient.[504] The expenditure must be approved by the AER so that we can comply with our obligations under the *Electricity Safety Act 1998* (Vic).

7.2.4 Our revised regulatory proposal

We maintain our position in our regulatory proposal for the amount of replacement capital expenditure for the 2016–2020 regulatory control period.

Table 7.2 Replacement capital expenditure forecasts ($ million, 2015)

Category	2016	2017	2018	2019	2020	Total
Replacement	49.1	50.1	62.6	57.4	41.3	**260.4**

Source: CitiPower

In this revised regulatory proposal, we:

- resubmit our 'unmodelled' replacement capital expenditure of $85.3 million ($2015, direct), for the reasons set out in the section above;
- accept the AER preliminary determination with respect to the six categories of expenditure modelled using the repex model; and
- accept the AER's preliminary determination with respect to pole top structures and SCADA expenditure.

7.3 Augmentation

We continue to support the growth and development of our communities by targeting investment in high growth areas to meet future demand. Capital expenditure to augment the network will also allow us to maintain the security, reliability and quality of supply of the network.

502 Jacobs, *CitiPower Proposed 2016-20 Repex Other*, 15 December 2015, p. 20.

503 Jacobs, *CitiPower Proposed 2016-20 Repex Other*, 15 December 2015, p. 17-24.

504 Jacobs, *CitiPower Proposed 2016-20 Repex Other*, 15 December 2015, p. 25.

In this section, we set out our concerns with the AER's preliminary determination, and justify our expenditure set out in this revised regulatory proposal. Importantly:

- the AER did not accept our proposed augmentation capital expenditure of $203.3 million ($2015) set out in the regulatory proposal, and have included an alternative estimate of $119 million ($2015) in the preliminary determination, a reduction of $84 million ($2015);
- the reduction in expenditure primarily reflects the AER's rejection of the program of works related to the decommissioning of the 22kV sub-transmission network originating at the West Melbourne Terminal Station (**WMTS**), as the AER considers that the works should be categorised as replacement;
- the AER also relied upon flawed and out-of-date demand forecasts from the AEMO to underpin its decision to reject some of our proposed demand-driven augmentation expenditure; and
- since the regulatory proposal, we have updated our demand forecasts as part of our annual planning process and this has been reflected in our revised regulatory proposal expenditure.

It is noted that the augmentation category set out in the AER's preliminary determination reflects the sum of the following categories set out in our regulatory proposal:

- augmentation expenditure;
- VBRC expenditure; and
- Supervisory Control and Data Acquisition (**SCADA**) which was contained in our non-network category.

7.3.1 Initial regulatory proposal

Our augmentation expenditure forecasts were prepared using different methodologies depending on whether the network constraint is demand or non-demand driven.

For augmentations that are driven by increasing demand on the distribution network, we used our demand forecasts that were prepared for the purposes of our 2014 Distribution Annual Planning Report (**DAPR**) to identify future constraints in our network. We expect peak demand to increase in specific areas of our network, which will be driven by:

- transfer of load around our network given our program to retire the 22kV sub-transmission network;
- population expansion, particularly along established and proposed transport corridors driven by changes in zoning; and
- block load additions from specific projects such as high density residential developments.

Where a future constraint was identified, we assessed the impact on customers using our probabilistic planning approach. If the impact was sufficiently large, we assessed a range of options to identify the solution that provided the highest net economic benefit to customers, or was the most effective, to address that constraint. We then used Load Indices to undertake a top-down check of the appropriateness of our forecasts.

The majority of our proposed expenditure was not driven by demand. Rather, it was driven by the need to maintain the security, reliability and quality of supply of the network. Quality of supply issues are often identified during the process to identify possible demand-driven constraints. Security of supply is often considered alongside a demand-driven augmentation project. For example, this includes our obligations under the Victorian *Electricity Distribution Code* to strengthen the security of supply in the Melbourne Central Business District (**CBD**).

Reliability of supply issues are often linked to replacement needs on the network. However, replacement projects can result in load being temporarily or permanently shifted around the network, leading to a need to augment the network.

Our major non-demand driven augmentation expenditure included the following projects:

- completion of the CBD Security of Supply project; and
- decommissioning of the 22kV sub-transmission network originating from West Melbourne Terminal Station (**WMTS**).

In terms of SCADA, our expenditure forecast was driven by the need to maintain the protection and control of the network. This took into account the changing communications technologies and equipment, and the capability required by the network now and for the future.

VBRC expenditure was driven by specific obligations that have been imposed on us by Energy Safe Victoria (**ESV**). Our forecast volumes and costs were based on information from similar obligations undertaken by Powercor in the 2011–2015 regulatory control period.

7.3.2 AER's preliminary determination

The AER did not accept our proposed augmentation expenditure of $203.3 million ($2015). The AER instead included an alternative estimate of $119 million ($2015), excluding overheads. This is 41 per cent less than the amount that we proposed.

The majority of the reduction in expenditure is based on the AER's rejection of the $74.7 million ($2015) program to decommission the 22kV sub-transmission network from WMTS. The AER appears to have rejected the project on the basis of categorisation, as it considers that the expenditure should be considered replacement rather than augmentation. The AER stated that:[505]

> *[W]e are not satisfied that the project is justified by the need to expand the capacity or capability of the network. It is not clear that CitiPower would have proposed this augmentation project if it were not for CitiPower's assessment of the condition of the relevant assets.*

The AER accepted our expenditure relating to the CBD security of supply upgrade plan.

With respect to demand-driven augmentation which predominately relates to the installation of high-voltage feeders and our low voltage network, the AER notes that:

- network utilisation reduced between 2010 and 2014;
- the AEMO 2014 connection point forecasts reflect a realistic expectation of demand over the 2016–2020 regulatory control period; and
- our demand forecasts for the 2016–2020 regulatory control period are approximately 20 per cent higher than AEMO's by the end of the regulatory control period.

On the basis of the above, the AER reduced our demand-driven augmentation forecasts by 20 per cent.

The AER approved our SCADA and VBRC expenditure. In terms of VBRC, the AER was satisfied that the bushfire mitigation plan is required to maintain the reliability and safety of the network and to comply with applicable regulatory obligations or requirements and would be prudent and efficient investment in the network.[506]

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[505] AER, *Preliminary Decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-46.

[506] AER, *Preliminary Decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-90.

7.3.3 Our response to the AER's preliminary determination

This section sets out our response to:

- classification of the expenditure for decommissioning the 22kV sub-transmission network; and
- the AER's use of AEMO's demand forecasts rather than our own reliable forecasts.

Classification of the expenditure for decommission the 22kV sub-transmission network

We strongly object to the AER rejecting our expenditure associated with the works to allow the decommissioning of the 22kV sub-transmission on the basis of the AER's incorrect view that the works are replacement, rather than augmentation.

First, if the AER maintains its position to reject this necessary augmentation expenditure, then the overall costs associated to undertake replacement works will be much higher. This is because we will still need to undertake like-for-like replacements on our transformers, switchgear and zone substations served from WMTS22. AusNet Services will also need to redevelop the 22kV switchyard at WMTS, rather than decommissioning those aged assets. As demonstrated by our updated business case, this option is not in the interests of consumers over the long term.[507]

Secondly, the AER does not have the ability to simply reject expenditure on the basis of classification. The capital expenditure objectives and criteria refer to the total forecast capital expenditure, and ensuring that expenditure is sufficient to allow us to meet our regulatory obligations, manage expected demand, and maintain the quality, reliability and security of supply. It does not suggest that the AER can reject required expenditure on the basis that it disagrees with our categorisation of the capital expenditure.

Third, if the AER considers that the expenditure is replacement, then it should have commented on the prudency and efficiency of that expenditure in the replacement category. The AER undertook this approach for Jemena, where the AER considered that expenditure included in the connections category represented augmentation expenditure. The AER then considered the expenditure within its assessment of Jemena's augmentation capital expenditure.[508] It is unclear why the AER took an inconsistent approach between distributors.

Fourth, we consider the expenditure to be appropriately categorised as augmentation. This is because the works are augmentation in nature.

Finally, we have previously undertaken works to decommission network assets which have been categorised as augmentation works. As a result, our historical augmentation expenditure reflects the inclusion of this expenditure. The AER has taken our historical expenditure by category into account when assessing our forecast expenditure for each category.

Decommissioning the 22kV sub-transmission network is in the long term interests of consumers

Continued operation of the 22kV network is uneconomic. This is demonstrated in our updated business case which provides a detailed analysis of the decision to maintain or decommission the existing 22kV sub-transmission network from WMTS.[509]

The analysis takes into account the two options of either leaving the 22kV sub-transmission network switched on and incurring the costs to maintain the network, or switching the network off and transferring the load to the 66kV sub-transmission network. The outcome of this analysis is shown in the table below.

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507 CitiPower, *Updated WMTS22 business case and response to AER Preliminary Decision*, December 2015.

508 AER, *Preliminary Determination, Jemena distribution determination 2016-20,* October 2015, p. 6-36.

509 CitiPower, *Updated WMTS22 business case and response to AER Preliminary Decision*, December 2015.

Table 7.3 Present value analysis of options for the 22kV sub-transmission network

Option	Costs (NPV, million)	Comment
Do nothing	N/A	• AER has already recognised that AusNet Services assets require replacement • Not a feasible option for CitiPower to maintain the safety, reliability and security of the network
Option 1: Like-for like replacement	99.1	• AusNet Services plans to replace the 22kV switchroom and 220/22 kV transformers at WMTS over a 10 year period • AusNet Services has high safety risks with existing assets, particularly the 22 kV switchboard • CitiPower plans to replace cables, transformers and switchgear over a 10 year period based on asset condition • Cost does not include replacement of CitiPower zone substation buildings, which also require upgrades in conjunction with asset replacements
Option 2: Full decommissioning	67.3	• Realise synergies between transmission and distribution • CitiPower transfers all load to 66kV network, decommission 22kV network and remediate sites, avoiding building replacement costs • AusNet Services has no need to replace WMTS 22kV assets (switchroom, transformers and fault limiting reactors)

Source: CitiPower, *Updated WMTS22 business case and response to AER Preliminary Decision*, December 2015, p. 11

This analysis clearly demonstrates that the cost of continuing to reliably and safely supply our customers that are currently served from WMTS is minimised under Option 2, which involves decommissioning the 22kV sub-transmission network and transferring the load to the augmented 66kV sub-transmission network. This option is therefore in the long term interests of consumers, and thus is consistent with the National Electricity Objective (**NEO**).

The works are augmentation in nature

CitiPower proposed a $72.1 million ($2015, direct) project in the non-demand driven augmentation category to replace the 22kV sub-transmission network with the 66kV sub-transmission network. While the driver of the works is the condition of the 22kV sub-transmission network, the nature of the works that we will undertake is augmentation.

The project involves augmentation of the network as it will result in a need to replace the capacity through the construction of feeders and new transformers to allow the decommissioning-related works to take place. The project consists of the following sub-components:

- $30.7 million ($2015) to upgrade and extend the 11kV network to allow transfers from the 22kV sub-transmission network;
- $34.9 million ($2015) to increase the capacity of existing 66kV zone substations or upgrade the zone substation to 66kV to allow transfers from the existing 22kV network; and
- $6.5 million ($2015) to upgrade or extend the 66kV sub-transmission network.

In terms of the upgrade to the 11kV network, the diagram below shows the extent of new feeders that must be built to connect existing feeders originating from the Laurens St (**LS**), Spencer St (**J**) and Tavistock Place (**TP**) zone substations to another zone substation connected to the 66kV network, thereby transferring the load. As these feeders are in the Melbourne CBD and inner suburbs, they must be constructed underground. The construction of new feeders to transfer the feeder originally served from TP zone substation to the Southbank (**SB**) zone substation must be built under the Yarra River. Additionally, the feeders originating from the J and TP zone substations also operate at 6.6kV, and so they must be upgraded to 11kV to be served from the Little Bourke St (**JA**) and SB zone substations where the transformers only step down the voltages from 66kV to 11kV.

Figure 7.4 Construction of new 11kV feeders required to transfer existing feeders to 66kV zone substations

Source: CitiPower

The zone substation located at the corner of Bouverie and Queensberry streets (**BQ**) does not have sufficient capacity to accommodate all of the load from the LS zone substation and feeder network. Therefore, we must erect a new third transformer in that zone substation and a 24MVAr capacitor bank, together with a new 11kV switchboard on a ring bus to provide circuit breakers for the 18 feeders that originated from LS but will now originate from BQ.

Secondly, we must undertake zone substation and sub-transmission line works to upgrade the assets from 22kV to 66kV. In particular, this involves replacing the two ageing transformers at the Dock Area (**DA**) zone substations which currently step down voltages from 22kV to 11kV, with two new 27MVA transformers that are able to reduce voltages from 66kV to 11kV. The sub-transmission lines from WMTS to DA also need to be upgraded to 66kV. Similarly, the two transformers at the Vic Rail (**VR**) zone substation need to be replaced with two new 13MVA transformers, as well as the construction of two new sub-transmission cables at 66kV.

It is clear from the above descriptions that the works involved in offloading the 22kV sub-transmission network are augmentation in nature. The replacement of the transformers do not involve 'incidental' augmentation, rather they are characterised as augmentation.

<u>Similar historical projects have been classed as augmentation</u>

The strategy of managing the risks of our ageing 22kV sub-transmission system have been outlined in the recent DAPR. Where it is economic and in the long term interest of the network and its customers, we will decommission these ageing 22/11-6.6kV zone substations and associated underground 22kV sub-transmission cables.

To enable the decommissioning, the high voltage distribution feeders of these zone substations will be extended to nearby 66/11kV zone substations. Upgrades to the 66kV sub-transmission network will be required as a result of the transfer of this load.

The most recent example of this strategy is the decommissioning of our Prahran (**PR**) zone substation, planned for completion at the end of 2015. This involved:

- extensions to our 11kV feeders;
- upgrade of our 66kV sub-transmission line; and
- the construction of a new transformer at the Balaclava (**BC**) zone substation to accommodate the additional load.

The costs of this project were included in our historical augmentation capital expenditure.

Demand-driven augmentation

The AER inappropriately applied a top-down cut to our demand-driven augmentation expenditure using AEMO's flawed and out-of-date demand forecasts. The AER should not have made any cut, and should have relied on own demand forecasts.

Contrary to the AER's claims, the AEMO 2014 demand forecasts are not a realistic expectation of the demand forecast. We have clearly set out reasons in chapter 5, as well as in appendix C to our regulatory proposal. Our demand forecasts are more reliable and appropriate and provide a more realistic expectation of demand over the 2016–2020 regulatory control period.

The methodology that the AER used to undertake the top-down cut involved a comparison of AEMO's 2014 maximum demand forecasts to our forecasts for our distribution area in 2020. The AER used the difference of around 20 per cent in 2020 to undertake its top down cut to our high and low voltage feeders augmentation expenditure.

Table 7.4 Comparison between AEMO and CitiPower maximum demand forecasts for 2016–2020 (MW, 10PoE, non-coincident)

Category	2016	2017	2018	2019	2020
AEMO	1530.5	1536.9	1546.8	1547.7	1538.5
CitiPower	1803.1	1868.1	1905.8	1935.1	1953.7
Differences in demand	15.1%	17.7%	18.8%	20.0%	21.3%

Source: AER, *Preliminary Determination, CitiPower distribution determination 2016–20*, October 2015, p. 6-42.

It is unclear why the AER has used the absolute difference in demand forecasts in 2020, in percentage terms, as the measure of the difference in forecasts. The use of this measure implicitly assumes that:

- forecasts are starting from the same point;
- the difference is driven solely by different forecasting methodologies; and
- the difference in 2020 underpins the expenditure cut across the entire 2016–2020 regulatory control period.

We do not consider that the AER's methodology is appropriate.

The AER recognises that the AEMO will publish updated connection point demand forecasts for Victoria, which it will consider in its final decision to reflect the most up to date data. As we have set out in chapter 5, the AEMO 2015 forecasts are not the most appropriate forecasts for the AER to rely upon. As AEMO continues to seek to improve the accuracy of the forecasts, the 2015 AEMO forecasts cannot be considered to provide a realistic expectation of forecast demand.

7.3.4 Our revised regulatory proposal

Our revised regulatory proposal relating to augmentation capital expenditure for the 2016–2020 regulatory control period is set out in the table below.

Table 7.5 Augmentation capital expenditure forecasts ($ million, 2015)

Category	2016	2017	2018	2019	2020	Total
Augmentation	41.5	67.2	47.4	29.2	16.2	**201.6**

Source: CitiPower

Our revised forecasts take into account the AER's preliminary determination and our revised demand forecasts. In particular, we have:

- included the program relating to the 22kV sub-transmission network, and if the AER disagrees with our categorisation it can include it in the replacement category; and
- removed programs that are no longer required as a result of our updated demand forecasts.

Our revised regulatory proposal with respect to demand driven augmentation is further discussed below.

Impact of changes to our demand forecasts

Our 2015 demand forecasts for the period to 2020 are lower than those prepared in 2014. This is due to a change in the macroeconomic environment, leading to lower forecasts of growth across key input parameters. The updated demand forecasts have been used in our 2015 DAPR.[510]

This has resulted in the deferment of the following small projects from our list of demand-driven augmentation works for the period from 2016 to 2020:

- uprate of the 66kV sub-transmission line from Kew (**Q**) zone substation to the Heidelberg (**HB**) zone substation owned by Jemena; and
- thermal uprate of the sub-transmission line from Deepdene (**L**) to Q zone substations.

A non-demand driven augmentation project relating to rearrangement of the 66kV sub-transmission loop at Fishermans Bend Terminal Station (**FBTS**), as a result of high fault levels, was removed as a consequence of AEMO turning off the synchronous condenser.

[510] CitiPower*, Distribution Annual Planning Report*, December 2015.

In total, our demand-driven augmentation forecasts have reduced by approximately $2.3 million ($2015) as a result of the update in our demand forecasts.

7.4 Connection

When customers seek to connect to our network, or change their existing connection, we need to meet our customer's requirements. The connections capital expenditure should allow us to connect customers to the network, including to supply new residential customers, assist industrial customers in expanding their operations, and to support the connection of renewable energy generators.

In summary, we have corrected the connections modelling, particularly the omission of $67 million ($2015) of gross capital expenditure relating to recoverable works. We have accepted the AER's methodology for forecasting gross customer connections, however we have corrected the methodology outlined by the AER for calculating customer contributions as well as taking account of the Victorian Government's planned introduction of Chapter 5A of the Rules.

In this section, we discuss the AER's preliminary determination, and justify our expenditure set out in this revised regulatory proposal. Importantly:

- the AER did not accept our proposed gross connections capital expenditure of $332.1 million ($2015) set out in the regulatory proposal, and have included an alternative estimate of $236.2 million ($2015) in the preliminary determination which represents a reduction of $95.9 million ($2015);
- the AER inadvertently omitted $67 million ($2015) of expenditure relating to recoverable works;
- the AER's rejected our forecasting methodology for high-volume connections, and instead substituted the expenditure with our historical expenditure for such connections leading to a further $28.9 million reduction. The historical expenditure was sourced from incorrect data provided by CitiPower in an information request;
- the AER accepted our forecast expenditure for low-volume connections;
- the AER has also rejected our forecasting methodology for calculating customer contributions, and has included an alternative amount which trends forward the average over the 2011–2014 period. The historical customer contributions was sourced from incorrect data that we provided in an information request; and
- our revised regulatory proposal adds back recoverable works, as well as calculating our customer contributions in a manner consistent with our regulatory requirements.

7.4.1 Initial regulatory proposal

We proposed connections expenditure that is broken down into two categories:

- high volume connections, which have been forecast using an econometric model prepared by the Centre for International Economics (**CIE**) and
- low volume connections, which have been forecast on a bottom-up build basis.

We engaged the CIE to prepare economic forecasts of connections which are typically associated with high volumes of activity. The CIE established historical relationships between the historical data and economic and demographic variables for the connection categories. Using correlations and econometric modelling, the CIE identified that population growth, dwelling growth and economic activity are statistically significant in explaining the number of customer connection projects.

Once the drivers of changes in the variables were identified, the CIE forecast the number of connection jobs using independent forecast data, in particular:

- for gross state product (**GSP**), using the same forecasts that AEMO uses for its demand forecasts; and

- for the number of dwelling approvals, using forecasts from the Victorian Department of Transport and Local Infrastructure.

The connection job forecasts produced by the CIE were mapped to our internal reporting categories, known as function codes. These volumes were then multiplied by the unit rate in each function code to prepare the connection expenditure forecasts.

For low volume connections, we undertook a bottom-up build of the expenditure for the categories of connections where there are typically low volumes. These forecasts reflected large customer connection projects that are highly likely to proceed, or for categories where there is currently no known major project in the forecast period we assumed expenditure based on the average major project expenditure. For smaller projects, our forecasts were based on the average expenditure for the 2011 to 2014 period.

Our forecasts for capital contributions were made in accordance with the Essential Services Commission's (**ESCV**) *Electricity Industry Guideline No. 14 — Provision of Services by Electricity Distributors* (**Guideline 14**) and *Electricity Industry Guideline No. 15 — Connection of Embedded Generators* (**Guideline 15**).

Our customer contribution forecasts were calculated by multiplying a calculated contribution rate by the gross connection capital expenditure for each function code. The contribution rates were calculated by first selecting a representative sample of 2013 customer projects for each connection category, and then updating the contribution rate to reflect changes in input parameters, such as our proposed rate of return and "x" factors, as well as changes in cost.

7.4.2 AER's preliminary determination

The AER did not accept our proposed gross connections expenditure of $332.1 million ($2015) and customer contributions of $144.9 million ($2015), excluding overheads. The AER instead included an alternative estimate of $236.2 million ($2015), and customer contributions of $58.8 million ($2015). The gross expenditure is 29 per cent lower than the amount that we proposed. While the AER's figures in the preliminary determination are indicated to be $2015/16 dollars, we believe the figures are $2015 (December).

With respect to high volume connections, the AER generally did not consider that the forecast volumes represented a realistic expectation of connection activity over the 2016–2020 regulatory control period. In particular:

- for residential connections, the AER was not satisfied that the forecasts of dwelling approvals represents the best possible forecast in the circumstances; and
- for commercial/ industrial connections, the AER was not satisfied that producing a forecast expenditure profile that purely uses GSP is appropriate.

On the basis of the above, the AER has instead included in its alternative capital expenditure estimate an amount which trends forward the average of the actual expenditure for each category of expenditure over the 2011–2014 period.

For low volume connections, the AER was satisfied that our forecasts for low volume connections are a realistic expectation of the required expenditure.

For customer contributions, the AER calculates that our customer contributions are forecast to be 81.7 per cent higher each year of the 2016–2020 regulatory control period compared with the 2011–2014 period.[511] The AER also considers that our approach to forecasting contributions, using a sample of projects in 2013, is not reflective

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[511] AER, *Preliminary Decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-67.

of the projects in the forecast period. On this basis, the AER rejected our forecasting methodology, and has included an alternative amount which trends forward the average over the 2011–2014 period.

7.4.3 Our response to the AER's preliminary determination

The AER's alternative estimate for customer connections expenditure will not allow us to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services, and thus is inconsistent with the capital expenditure objectives set out in clause 6.5.7(a) of the Rules. In this regard, we set out below:

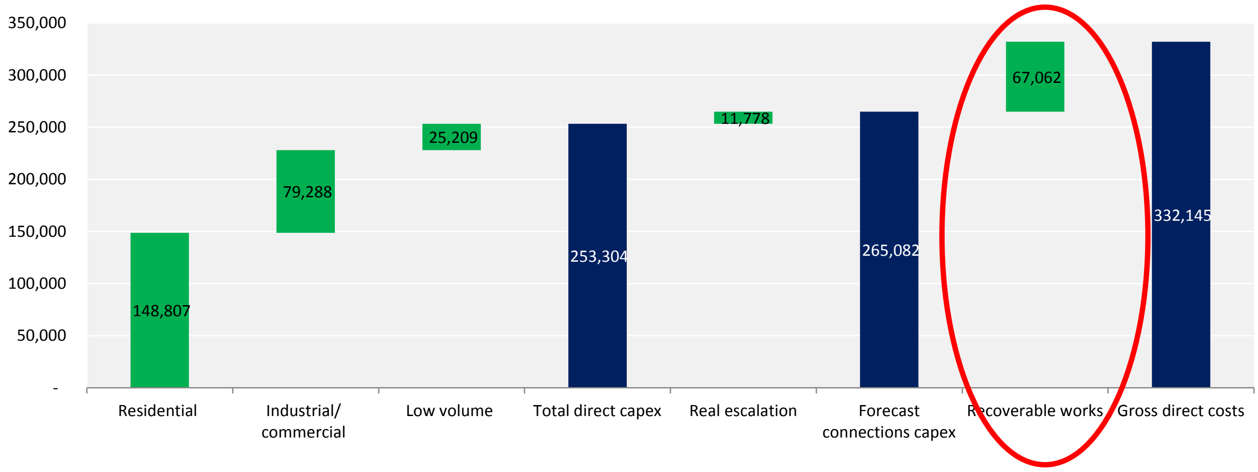
- errors in connections modelling, including the omission of recoverable works;
- comments on the AER's approach to high-volume connections; and
- concerns regarding the AER's approach to customer contributions.

These matters are discussed in turn below.

Recoverable works

CitiPower proposed gross connections capital expenditure of $332.1 million ($2015), and the build-up of that forecast is shown in the figure below. However, Table 6.12 of the AER's preliminary determination sets out that we only proposed $265.1 million ($2015) of gross connections capital expenditure. The AER has inadvertently omitted $67 million ($2015) of capital expenditure relating to recoverable works.

Figure 7.5 Our proposed connections capital expenditure ($2015 thousands)



Source: CitiPower

The AER has acknowledged that it inadvertently omitted recoverable works. In an email to us on 12 November 2015, the AER states that:[512]

> *In the view of AER staff, as you'll see in the summary sheet, tables 6.12 and 6.13 of our connections decision for CitiPower are presented exclusive of recoverable works. These costs should have been added back for the purposes of calculating total gross and net capex. The AER's preliminary decision as presented in both Table 6.2 and the capex model omits the recoverable works. The result is that instead of net capex being*

[512] AER, *Email from Anthony Bell (AER) to Renate Tirpcou (CitiPower) re Connections and Incentive Rates*, 12 November 2015.

$177.4 million as included in our prelim decision, it should have been $190.8 million. That is, the constituent decision for capex is $13.41 million too low over 2016–20 for CitiPower.

We seek this to be rectified in the final determination.

For completeness, we note that the AER has classified recoverable works as standard control services in the final framework and approach (**F&A**) paper for Victoria.[513] In the F&A, the recoverable works are described as 'customer initiated undergrounding and/or rearrangement of distribution assets serving that customer'.

AER's use of historical expenditure to forecast connections for high-volume connections

We consider that there is merit in taking into account economic drivers in preparing connection forecasts. Such an approach is consistent with our forecasts for demand, which are used to develop our forecasts for augmentation expenditure.

We note, however, the AER's comments with respect to the econometric modelling undertaken to calculate our high-volume connection volumes. We have previously outlined our concerns with the use of historical averaging in the preparation of connection forecasts, as it fails to take account of the broader economic factors that impact the historical period and the changes towards the future period. We note that we overspent our connections allowance in the 2011–2015 regulatory control period where the allowance was set using historical average information.

That said, we will not object to the use of historical averaging for high-volume connection volumes by the AER for the purposes of the final determination.

Comparison of historical and forecast expenditure

The AER's connection model indicates that the AER made the following assessment of our connections expenditure.

Table 7.6 AER connections model ($ million, 2015)

	Regulatory proposal	AER determination	Difference
Residential	155.8	152.4	-3.4
Commercial/ industrial	83.1	57.6	-25.4
Low volume	26.1	26.1	-
Recoverable works	67.0	67.0	-
Gifted assets	-	-	-
Real escalation	-	-	-
Total	**332.1**	**303.3**	**-28.8**

Source: AER, CitiPower connections - AER workings.xlsx

The historical expenditure that the AER has used to substitute in place of our forecast expenditure was in nominal dollars, rather than 2015 dollars. This is clear as the numbers used by the AER are identical to those

513 CP PUBLIC ATT 2.1 –AER, *Final Framework and Approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016*, 24 October 2014, p. 40.

provided in our Category Analysis RIN for each relevant year, which are provided in nominal dollars.[514] As a result, the figures are understated.

The forecast expenditure used by the AER consists of direct costs plus real escalation. In particular, the AER's calculation of residential, commercial/ industrial and low volume connections equates to $265 million ($2015), reflecting our forecasts of $253.3 million ($2015) of direct cost plus $11.7 million ($2015) of real escalation (see waterfall diagram above).

The AER assesses real escalation at a total capital expenditure level, rather than at the category level. By using historical expenditure as a substitute for forecast expenditure, the AER has essentially also removed our real cost escalation component of our connections expenditure. This is in addition to the AER reducing our real cost escalator by $11.2 million ($2015) at the total capital expenditure level in the preliminary determination.[515] That is, the AER has removed our real cost escalation twice.

Applying the AER's methodology correctly, where the historical costs are cited in $2015 and the real escalation component is not removed twice, we have provided below a corrected assessment of the AER's preliminary determination.

Table 7.7 Correcting the AER's Preliminary Determination to remove double removal of real escalators ($ million, 2015)

	Regulatory proposal	Correction of AER figures	Difference
Residential	148.8	163.5	14.7
Commercial/ industrial	79.3	61.8	-17.4
Low volume	25.2	25.2	-
Recoverable works	67.0	67.0	-
Gifted assets	-	-	-
Real escalation	11.7	11.7	-
Total	**332.0**	**329.2**	**-2.8**

Source: CP CONFIDENTIAL MOD 1.18 – CitiPower, *CP Connections Capex*.xlsm

We seek for the following to be rectified in the AER's final determination:

- add back recoverable works;
- replace historical connections capital expenditure expressed in nominal dollars with values expressed in real 2015 dollars; and
- add back the real escalation that we proposed.

Calculation of customer contributions

Our forecasts for customer contributions were provided by applying forecast methodology set out in the ESCV's Guideline 14 and Guideline 15.

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514 Refer CP CONFIDETIAL RIN 1.19– CitiPower, *2009-13 Category Analysis RIN*, tab 2.5 Connections; CP CONFIDETIAL RIN 1.20– CitiPower, *2014 Category Analysis RIN*, tab 2.5.

515 AER, *Preliminary Decision, CitiPower distribution determination 2016–20*, October 2015, p. 6-11.

In contrast, the AER used our average historical contributions in the 2011–2014 period as a substitute for our estimate of customer contributions for high-volume connections. This approach is incorrect, as the AER must take into account the appropriate "x" factor and discount rate for that regulatory control period.

Under Guidelines 14 and 15, the calculation of customer contributions is based on formula which assesses the extent to which the cost of the connection exceeds the revenues that the distributor will receive through the provision of that connection. At a high level, the calculation involves:

$$CC = [IC - IR] + SF$$

where:

CC is the maximum amount of the customer's capital contribution

IC is the incremental cost in relation to the connection offer and includes customer specific assets and shared network assets

IR is the amount of incremental revenue in relation to the connection offer which is calculated as the present value of expected distribution revenue over 30 years (residential) or 15 years (non-residential)

SF is the amount of any security fee

A key parameter in the calculation is the "x" factor. This is used in calculating the incremental revenue and relates to the rate at which prices are forecast to change over subsequent regulatory control periods for the assumed life of the connection.

During the 2011–2015 regulatory control period, our "x" factor was 7.8 per cent. That is, in the calculation of incremental revenue for a residential connection, prices were assumed to increase by 7.8 per cent annually in real terms from 2016 for the remainder of the 15/30 year assumed asset life.

In contrast, this "x" factor reduces to 0.45 per cent for the 2016–2020 regulatory control period. This means that for a connection that costs the same amount, the incremental revenues that the distributor assumes it will receive will be materially lower in the 2016–2020 regulatory control period compared with the 2011–2015 regulatory control period, assuming all other parameters remain unchanged. Consequently, the amount that the customer will be required to contribute for the connection will increase.

Additionally, the discount rate should be the pre-tax real rate of return, which is 7.86 per cent in the current regulatory control period and 4.12 per cent in the AER's preliminary determination.

Therefore, it is incorrect to assume that customer contributions will remain at average historical levels for the 2016–2020 regulatory control period.

In the period since April 2015 when we submitted our regulatory proposal, the Victorian Government has announced its intention that we adopt Chapter 5A of the Rules during the 2016–2020 regulatory control period. This will impact the calculation of customer contributions, as it will also require the ESCV to rescind Guidelines 14 and 15.

While the legislative bill that was introduced into the Victorian Parliament in December 2015 did not specify a date from when we would adopt the new Rule, a default date of 1 January 2017 was contained in the draft legislation. For the purposes of this revised proposal, we therefore assume that customer contributions will be calculated:

- in 2016, in accordance with Guideline 14 and 15; and
- in 2017 to 2020, in accordance with Chapter 5A of the Rules.

The historical customer contributions relied on by the AER to forecast high-volume customer contributions were incorrectly reported to the AER in an information request and did not reconcile with customer contributions reported in our annual Regulatory Information Notices (**RIN**s) and regulatory proposal.

It is also noted that the AER omitted the customer contributions associated with recoverable works in its calculations.

We seek for the following to be rectified in the AER's final determination:

- correct for the change in x factor and rate of return;
- reflect the application of Guideline 14 in 2016 and Chapter 5A in 2017 to 2020;
- apply corrected historical customer contributions as a base for forecasting high-volume customer contributions; and
- add back recoverable works contributions.

7.4.4 Our revised regulatory proposal

Our revised regulatory proposal relating to gross and net connections capital expenditure for the 2016–2020 regulatory control period is set out in the table below.

Table 7.8 Connections capital expenditure forecasts ($ million, 2015)

Category	2016	2017	2018	2019	2020	Total
Gross connections	66.3	73.7	64.7	62.9	62.4	**330.0**
Customer contributions	32.6	39.9	34.6	31.9	31.4	**170.4**
Net connections	**33.7**	**33.8**	**30.1**	**31.0**	**31.0**	**159.6**

Source: CitiPower

Our revised forecasts reflect the following matters:

- inclusion of $67 million ($2015) of recoverable works expenditure that the AER inadvertently omitted from the preliminary determination;
- acceptance of the AER's approach to forecasting gross high-volume connections expenditure by using the average of historical expenditure;
- replacement of historical connections capital expenditure expressed in nominal dollars with values expressed in real 2015 dollars;
- correction of the AER's forecasting methodology by ensuring that real escalation is treated separately; and
- updating of our methodology for calculating customer contributions to reflect anticipated changes in regulations, correcting for the change in x factor and rate of return, correction of a reporting error and to include recoverable works contributions.

Our approach to calculating customer contributions for the purposes of the revised proposal is set out in detail below.

Calculation of customer contributions under Chapter 5A

Under Chapter 5A, the capital contribution component of a connection is calculated as follows:

$$CC = ICCS + ICSN - IR + SF$$

where:

ICCS is Incremental Cost Customer Specific;

ICSN is Incremental Cost Shared Network subject to an agreed augmentation threshold, but excluding micro-embedded generators

IR is Incremental Revenue which is calculated as the present value of expected distribution revenue over 30 years (residential) or 15 years (non-residential). Real prices increases beyond the end of the regulatory control period are to be assumed to be zero. This is different to Guideline 14 which requires that real price increases beyond the end of the regulatory control period be set equal to the real price increase in the last year of the regulatory control period

SF is the amount of any security fee

Approach to calculating customer contributions

Under Guideline 14 and Chapter 5A, capital contributions are primarily calculated as the difference between incremental cost and incremental revenue.

For the purposes of the revised regulatory proposal, we have assumed that incremental costs for a particular connection remain unchanged.

The calculation of incremental revenue, however, will differ in 2016, and 2017 to 2020.

The following table summarises the x factor and rate of return assumptions that would be applied to calculate incremental revenue in 2014, 2016 and 2017, assuming Chapter 5A takes effect from 1 January 2017 and using the AER's preliminary determination values for 2016 to 2020.

Table 7.9 X factor and rate of return assumptions

	Discount rate						Real price change	
		2015	2016	2017	2018	2019	2020	2021+
2014 connection	7.86%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%	7.80%
2016 connection	4.12%	7.80%	-6.75%	-6.75%	0.45%	0.45%	0.45%	0.45%
2017 connection	4.12%	7.80%	-6.75%	-6.75%	0.45%	0.45%	0.45%	0.00%

Source: CitiPower

The following table compares the customer contribution that would be calculated in 2014, 2016 and 2017 using the example of a residential development connection with an incremental cost of $0.4 million ($2015). It illustrates that the difference in incremental revenue and customer contribution is materially different between 2014 and 2016/17.

Table 7.10 Example of calculation of residential customer contributions

	2014 connection	2016 connection	2017 connection
Relevant instrument	Guideline 14	Guideline 14	Chapter 5A
Annual usage (MWh)	100	100	100
Average tariff in 2014 (c/kWh)	10	10	10
Incremental revenue (30 years)	$276k	$181k	$174k
Incremental cost (assumption)	$400k	$400k	$400k
Customer contribution	**$124k**	**$219k**	**$226k**

Source: CitiPower

To remove the impact of the final year "x" factor, we have proposed the same "x" factor that the AER set out in our preliminary determination. We have then:

- separated out the calculations between residential and non-residential customers given that incremental revenue for residential connections is calculated over a 30 year period; whereas it is only 15 years for non-residential customers;
- derived incremental revenue in the 2011–2014 period by deducting incremental cost from customer contributions;
- calculated an incremental revenue scaling factor to take into account the new "x" factors and rate of return; and
- recalculated the customer contributions using the scaled incremental revenue.

In our revised regulatory proposal, the above scaling methodology has been applied to the AER's connection model that formed part of the preliminary determination.

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Capital expenditure – non-network 8

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8 Capital expenditure - non-network

This chapter discusses our non-network capital expenditure forecast for the 2016–2020 regulatory control period. Our non-network capital expenditure is separated into three categories—information technology (**IT**) and communications, equity raising costs, and other non-network capital expenditure.

Our revised regulatory proposal is consistent with the forecast of other non-network capital expenditure included in the AER's preliminary determination. Similarly, our revised regulatory proposal is consistent with the method and unit rates set out in the AER's preliminary determination for calculating equity raising costs, although our forecast is updated to reflect our revised regulatory proposal cash flows.

For the reasons set out in this chapter, however, we do not accept the following components of the AER's preliminary determination in relation to IT and communications capital expenditure:

- the removal of the entirety of our proposed RIN compliance expenditure; and
- the application of a proportional reduction across all expenditure.

Our revised regulatory proposal also includes IT and communications capital expenditure required to implement initiatives outlined by the Australian Energy Market Commission (**AEMC**) following its Power of Choice review. The impact of these initiatives was not included in the development of our regulatory proposal as sufficient details were not available at that time to robustly determine a forecast of costs. The AEMC has since published its final rule for the majority of its Power of Choice initiatives.

8.1 Rule requirements

As discussed in chapter 7 of our revised regulatory proposal, the National Electricity Rules (**the Rules**) require our building block proposal include the total forecast capital expenditure for the 2016–2020 regulatory control period which is required to achieve each of the capital expenditure objectives.

The Rules also require the Australian Energy Regulator (**AER**) to accept our forecast if it is satisfied that the total of our forecast capital expenditure for the 2016–2020 regulatory control period reasonably reflects the capital expenditure criteria. In making this assessment the AER must have regard to the capital expenditure factors which include (but are not limited to) benchmarking and our historical performance.

8.2 Information technology and communications

Our forecast of IT and communications capital expenditure is split into the following seven streams:

- compliance—maintaining regulatory, statutory, market and legal compliance via investment in systems, data, processes and analytics to provide the functionality and reporting capability to efficiently comply with statutory and regulatory obligations;
- currency—maintaining vendor support for solutions and core software within acceptable and consistent versions and proactively ensuring that business needs and service definitions are fulfilled using a minimum of computing resources, and that applications have the capacity to support business volumes within service level targets;
- customer enablement—investment in systems and capabilities that support the increasing complexity of market relationships and customer needs. Responding to evolving industry forces, energy market and industry changes that are being progressed by regulators to increase innovative participation by customers in the market;
- security—ensuring customers continue to receive a reliable distribution of controlled power, by monitoring, managing and mitigating threat of cyber and network security breaches in a prudent manner;

- smarter network—enabling networks for the future through targeted investment in technologies that maintain and improve customer service standards and enable new and innovative services;
- infrastructure—prudently optimising asset lifecycles of infrastructure assets to ensure agreed service levels can be met at the lowest lifecycle cost and supporting normal business growth; and
- device replacement—optimising the investment in end user devices to enable workforce operability whilst optimising cost and performance.

We further split our forecast of IT and communications capital expenditure into recurrent and non-recurrent costs. The split of expenditure into these categories is based on the following definitions:

- recurrent expenditure relates to replacement, upgrades and maintenance of existing functionality and systems in our IT landscape (e.g. this includes the replacement of our billing system, device replacement, system upgrades, expansion and refresh of infrastructure); and
- non-recurrent expenditure relates to new functionality or new (not replacement) systems that will be introduced to our IT landscape (e.g. this includes the Customer Relationship Management system (**CRM**), new Regulatory Information Notice (**RIN**) reporting requirements and decryption software incorporated into the security stream).

The split between recurrent and non-recurrent expenditure is reflective of our approach to investing in new technology where appropriate, and then managing the effective life of that investment through fit-for-purpose enhancement and modification. This approach also recognises the increasing scope of IT systems that support the efficient operation of our business and the refresh requirements across these systems.

8.2.1 Initial regulatory proposal

Our forecast of the total IT and communications capital expenditure for the 2016–2020 regulatory control period included in our regulatory proposal is set out in table 8.1.

Table 8.1 IT and communications capital expenditure 2016–2020 ($ million, 2015)

Stream	Total
Compliance	11.9
Currency	18.9
Customer enablement	12.9
Security	10.5
Smarter network	18.2
Infrastructure	7.3
Device replacement	1.3
Total	**81.1**

Source: CitiPower

8.2.2 AER's preliminary determination

The AER did not accept our forecast of IT and communications capital expenditure in its preliminary determination, as it was not satisfied that our forecast reasonably reflected the efficient costs that a prudent operator would require to achieve the capital expenditure objectives.

In its assessment of our forecast IT and communications capital expenditure, the AER found the following:[516]

- the business cases for our smarter networks expenditure demonstrated that the sub-projects each provide an economic return individually and as a total package; and
- the costs to provide our new customer relationship management (**CRM**) and billing system are prudent and efficient.

The AER, however, did not accept any of our proposed expenditure for complying with our RIN obligations. The AER also stated that our IT security business cases did not quantify the cost of the risk we are attempting to address, nor did they provide sufficient cost benefit or options analysis.[517]

Based on the assessments above, and a review of our remaining IT and communications capital expenditure forecast, the AER's alternative estimate was derived as follows:[518]

- removed the entirety of our forecast expenditure for RIN compliance;
- applied a proportional reduction of 10 per cent to all remaining expenditure (after removing the RIN compliance expenditure) on the basis of projects that it considered were not sufficiently justified, were speculative and therefore cannot be accurately costed, and for projects where some of the expenditure was not justified.

8.2.3 Our response to the AER's preliminary determination

The AER's assessment of our proposed IT and communications capital expenditure has regard to a range of important factors. We have applied the AER's assessment in regard to many of these factors.

We do not accept the AER's approach, however, for the following components of its preliminary determination:

- the removal of the entirety of our proposed RIN compliance expenditure; and
- the application of a proportional reduction across all expenditure.

This section discusses these two components of the AER's preliminary decision in detail.

RIN compliance expenditure

Our forecast of IT and communications capital expenditure for the 2016–2020 regulatory control period, as set out in our regulatory proposal, included forecast capital expenditure to meet the AER's new RIN reporting requirements. These new reporting requirements include the need to eliminate historical estimates from our RIN responses, and instead, report 'actual' data. The corresponding expenditure was for changes to front-end business process and system capabilities, as well as increased data repository functionality and automated reporting. Our forecast was supported by a business case developed by KPMG.[519]

In its preliminary determination, the AER stated they were not satisfied that the magnitude of our proposed RIN compliance expenditure reflected prudent and efficient expenditure. The basis of the AER's concerns included the following two reasons:[520]

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516 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6–102.

517 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6–103.

518 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6–104.

519 CP PUBLIC APP E.43 - KPMG, *Business Case for expenditure to meet RIN requirements*, April 2015.

520 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6–103.

- the magnitude of our proposed RIN compliance expenditure relative to that proposed by other businesses; and
- when the AER sought information from network service providers on the cost of compliance when they initially consulted on RIN obligations, we did not provide any estimates.

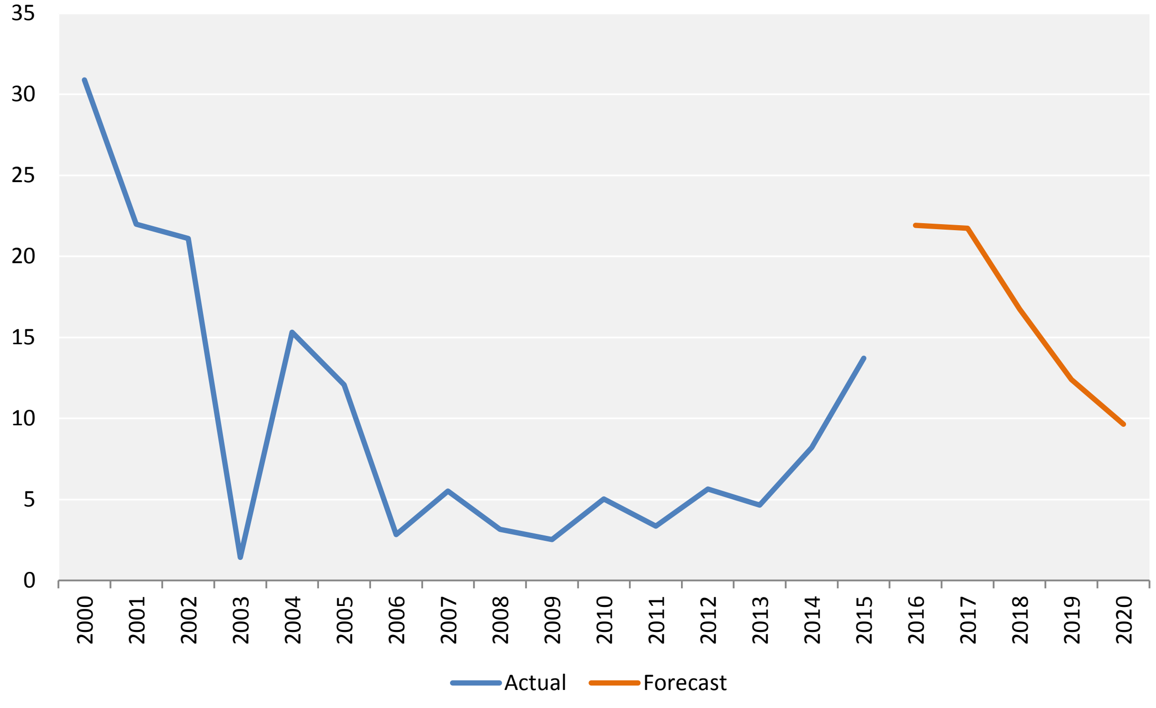
Our response to the AER's reasons, and our revised capital expenditure forecast for RIN compliance are set out below. Our revised capital expenditure forecast is further discussed in our attached business case.[521]

<u>Consistency across other businesses</u>

The AER stated that it expected the costs associated with complying with RIN obligations to be relatively consistent across different business.[522] In this context, the AER noted that while SA Power Networks and United Energy had also proposed IT capital expenditure for compliance with RIN requirements, a number of other distributors had not (or had only proposed small amounts of expenditure).[523]

The AER, however, acknowledged that each business may be starting from a different position regarding its existing systems and data availability.[524] We agree with this statement. As shown in figure 8.1, IT and communications capital expenditure may be lumpy. This reflects longer term investment lifecycles for foundation systems, as opposed to regular replacement and upgrades driven by technology and software obsolescence.

Figure 8.1 Historical IT and communications capital expenditure ($ million, 2015)



Source: CitiPower

[521] CitiPower and Powercor, *RIN reporting compliance*, December 2015.

[522] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6–103.

[523] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6–103.

[524] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6–103.

It should also be recognised that each business may propose different solutions to achieve compliance. For example, the AER cited Jemena as a business that had not proposed capital expenditure to comply with its RIN obligations.[525] Although Jemena did not forecast any capital expenditure, it proposed a corresponding operating expenditure step change of $19.7 million. In response to Jemena's forecast, the AER stated that RIN compliance is a new regulatory obligation that may give rise to a justifiable step change.[526]

Further, in its expenditure forecast assessment guideline, the AER acknowledged that distributors will face expenses as a consequence of business and operational changes required to comply with new data requirements and adjusted reporting standards.[527] These costs were expected to include (but were not limited to) training staff, adjusting IT systems, and reorganising data compliance procedures.[528] The AER considered the implementation of the new techniques and accompanying data requirements will be net benefit positive.[529] Consistent with these statements, in its final decision for SA Power Networks the AER made an allowance for forecast capital expenditure relating to RIN compliance totalling $8.6 million.[530] The AER also approved a related operating expenditure step change for SA Power Networks totalling $6.4 million.[531]

Given the AER's approach for SA Power Networks, and its statements regarding Jemena's proposed step change, it is inconsistent for the AER to reject the entirety of our RIN compliance expenditure on the basis of consistency across other distributors.

<u>Initial consultation on RIN impacts</u>

In its preliminary determination, the AER stated that because we did not provide an estimate of the costs of complying with the RIN obligations during its RIN consultation process, it is reasonable to assume that the cost would not be material.[532] In particular, the AER referenced its consultation process for the development of its category analysis and economic benchmarking RINs that were undertaken in 2013 and early 2014.

Our submission in response to the AER's draft RIN for the category analysis RIN, however, clearly indicated that we expect the cost impact to our business to be material:[533]

> *[T]he Businesses are committed to making the necessary business systems and operational changes in order to provide the AER its information requirements. However, given the high cost of implementing new business systems and making operational changes, the Businesses require a high level of certainty from the AER as to future information requirements.*

Moreover, contrary to the position set out in its preliminary determination, the AER acknowledged the views of distributors such as us in its explanatory statement for the final category analysis RIN:

> *During consultation we prompted NSPs to quantify the likely cost of compliance with the draft RINs, in terms of person-hours taken to provide certain information and expenditures. Many NSPs were unable to do this, however this does not detract from their view that the costs would be substantial.*

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525 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6–103.

526 AER, *Preliminary decision, Jemena distribution determination 2016-20*, October 2015, p. 7–81.

527 CP PUBLIC ATT 9.4 - AER, *Better Regulation, Explanatory statement, Expenditure forecast assessment guideline*, November 2013, p. 14.

528 CP PUBLIC ATT 9.4 - AER, *Better Regulation, Explanatory statement, Expenditure forecast assessment guideline*, November 2013, p. 14.

529 CP PUBLIC ATT 9.4 - AER, *Better Regulation, Explanatory statement, Expenditure forecast assessment guideline*, November 2013, p. 14.

530 AER, *Final decision, SA Power Networks determination 2015−16 to 2019−20*, October 2015, p. 6-124.

531 AER, *Final decision, SA Power Networks determination 2015−16 to 2019−20*, October 2015, p. 7-75.

532 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6–103.

533 CitiPower and Powercor Australia, *Submission to AER on draft regulatory information notice for category analysis benchmarking*, 17 January 2014, p. 1.

Notwithstanding that the AER's position in its preliminary determination draws a different conclusion to that it previously acknowledged, the Rules do not permit the AER to reject our proposed expenditure on the basis that we previously did not quantify forecast cost impacts. Notably, as we have now responded to multiple iterations of the AER's RINs, we have a much greater understanding of the content required by the AER and of the internal costs and process required to provide such information.

Our revised capital expenditure forecast for RIN compliance

Our revised capital expenditure forecast for RIN compliance is set out in detail in our attached business case.[534] This business case provides a summary of our RIN reporting journey to date, an outline of our existing asset management business model and how it delivers 'actual' data for many RIN elements, and the options considered to meet our RIN requirements. The benefits of the RIN reporting solution that accrue to the community, and indirectly to us, are also discussed.

Since lodging our regulatory proposal in April 2015, we have continued to understand the extent to which the data we currently report in the AER's economic benchmarking and category analysis RINs can already be considered 'actual' data. This analysis was informed by relevant comments made by the AER in its preliminary determinations, and subsequent discussions with our auditors (who are required to sign-off on our final RIN responses). Our revised forecast is based on amendments to our existing operating model (including system enhancements).[535] We consider this expenditure contributes to a total forecast capital expenditure for the 2016–2020 regulatory control period which is required to achieve each of the capital expenditure objectives.

Our review of our RIN compliance obligations also considered any incremental operating expenditure impacts. Consistent with the AER's approach for SA Power Networks, and its comments in response to Jemena's regulatory proposal, we have included a corresponding operating expenditure step change. This step change is discussed in our operating expenditure chapter.

Proportional reductions across all expenditure

In its preliminary determination, the AER applied a proportional reduction of 10 per cent to our IT and communications capital expenditure forecast on the basis of projects that it considered were not sufficiently justified, were speculative and cannot be accurately costed, and for projects where some of the expenditure was not justified.[536] After removing the RIN compliance expenditure, the AER applied this reduction to our entire remaining IT and communications capital expenditure forecast. This is despite the AER stating the business cases for our smarter networks expenditure and our new CRM and billing system demonstrated that these costs are prudent and efficient.

The AER only provided a high level discussion regarding the projects it considered were not sufficiently justified. We provided business cases for over 100 separate capital expenditure projects. The AER provided no indication as to how it assessed the majority of these business cases, nor did it specify which business cases it considered were not sufficiently justified. On this basis, our ability to respond to the AER's preliminary determination in any substantive detail is limited.

Should the AER maintain its view that a 10 per cent proportional reduction is appropriate, we consider the application of such a reduction should exclude our smarter networks and CRM and billing expenditure (given the AER's recognition that these costs are prudent and efficient). Our forecast IT capital expenditure for the 2016–

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534 CitiPower and Powercor, *RIN reporting compliance*, December 2015.

535 CP PUBLIC RRP MOD 1.56 – CitiPower, RIN compliance expenditure.xlsx.

536 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6–104.

2020 regulatory control period, as set out in our attached model, is based on this approach.[537] That is, it includes 100 per cent of our forecast smarter networks, CRM and billing and revised RIN compliance expenditure, plus 90 per cent of the residual from our regulatory proposal).[538]

8.2.4 Our revised regulatory proposal

Our forecast of the total IT and communications capital expenditure for the 2016–2020 regulatory control period included in our revised regulatory proposal is set out in table 8.2. This expenditure is supported by the analysis outlined in our regulatory proposal and section 8.2.3 above.

Table 8.2 IT and communications capital expenditure 2016–2020 ($ million, 2015)

Stream	Total (unescalated)	Total (escalated)
Compliance (including additional expenditure to comply with the Power of Choice initiatives)	16.3	16.8
Currency	16.5	17.0
Customer enablement	12.6	13.0
Security	9.2	9.5
Smarter network	17.5	18.1
Infrastructure	6.5	6.8
Device replacement	1.2	1.2
Total	**79.7**	**82.4**

Source: CitiPower

Our forecast of total IT and communications capital expenditure set out in table 8.2 differs from that included in our regulatory proposal due to reduced RIN compliance costs and the proportional reduction to specific expenditure streams. Our revised regulatory proposal also includes expenditure required to implement Power of Choice initiatives that have been finalised by the AEMC since our regulatory proposal was submitted. These Power of Choice initiatives are discussed below.

For clarity, our forecast of total IT and communications capital expenditure for the 2016–2020 regulatory control period does not include device replacement expenditure associated with mobile devices (such as phones and tablets). Instead, this expenditure is the subject of an operating expenditure step change. As outlined in our operating expenditure chapter, however, if the AER rejects this capital for operating expenditure trade-off, the AER should add the corresponding capital component back into our revised regulatory proposal capital expenditure forecast (totalling $2.1 million ($2015)).

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537 CP PUBLIC RRP MOD 1.20 – CitiPower, IT capex.xlsx.

538 For clarity, as set out in section 8.2.4, our revised regulatory proposal also includes our forecast of costs required to comply with the AEMC's finalised Power of Choice initiatives.

Expanding competition in metering and related services (including framework for open access and common communication standards, and implementation advice on the shared market protocol)

On 26 November 2015, the AEMC published its final rule in relation to expanding competition in metering and related services. This rule opens up the provision of metering services to more competition, with the aim to promote efficient investment and increased consumer choice in products and services. It includes a number of other features to support a competitive framework, including minimum requirements for new and replacement meters for small customers and new obligations so that security of, and access to, advanced meters and the services they provide are managed appropriately.[539]

This rule also gives effect to the related recommendations outlined in the AEMC's final report for the framework for open access and common communication standards, as well as the AEMC's implementation advice on the shared market protocol.

To determine the impact of the AEMC's final rule, we engaged Accenture to assist us in reviewing the changes required to our existing IT processes and associated systems to remain compliant in Victoria under the new rules.[540] Accenture's assessment is attached to our revised regulatory proposal, and is summarised below.[541]

<u>Accenture's assessment process: overview</u>

Accenture began its assessment by reviewing the relevant rule changes proposed by the AEMC. Accenture's forecast of the costs associated with the introduction of metering contestability included those required for complying with the AEMC's changes to the framework for open access and common communication standards, and its implementation advice on the shared market protocol. Accenture included these costs in its assessment of the impact of metering contestability due to the overlap between these industry changes, and the interdependencies between the functionality these separate initiatives will deliver.

Following its review of the proposed rule, Accenture assessed the functionality and operation of our existing process and systems to identify the changes required to remain compliant. This included multiple meetings with subject matter experts within the business. These meetings initially focused on ensuring Accenture understood our existing system landscape, and subsequently, to the test whether the proposed changes could be met by alternative and/or existing options.

Accenture then grouped the required changes into broad work packages, and formed an estimate on the effort required to achieve these (as opposed to individually costing each process and system change in isolation). This ensured Accenture's forecast incorporated efficiencies expected from a holistic approach to implementing process and system changes.

The final step in Accenture's assessment was to outline an implementation roadmap.

<u>Accenture's cost forecast: summary</u>

Accenture found that the introduction of metering contestability will require 125 system and 28 process changes in order for us to remain compliant in Victoria under the new rules, plus corresponding training and project management costs. Based on Accenture's modelling, implementing these changes equates to $16.3 million over the 2016–2020 regulatory control period (in total for CitiPower and Powercor).

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539 See, for example: AEMC, *Information sheet, Competition in metering services*, 26 November 2015.

540 CitiPower and Powercor, *Metering contestability - pre-gate approval*, December 2015.

541 Accenture, *Metering contestability - process and system impacts*, 23 October 2015.

As outlined previously, Accenture's forecast incorporated efficiencies expected from a holistic approach to implementing process and system changes. Accenture also incorporated sensitivity analysis through multiple internal reviews focused on identifying alternative preferable options.

Accenture noted that changes to our existing processes and systems will be required irrespective of the extent to which competition occurs. For example, based on our existing data, in excess of 134,000 meters will need to be replaced due to faults, abolishments or new connections throughout the 2016–2020 regulatory control period. These meters will automatically become contestable under the new rules, and the processes required to manage such churn can only be effectively managed through amending our IT processes and systems.

In order to comply with new rules by 1 December 2017 (i.e. the timeframe set out in the Rules), Accenture stated that work must commence as soon as possible. This is reflected in Accenture's modelling.

<u>Consideration of alternative options</u>

In addition to the work undertaken by Accenture, we considered the following alternative options to comply with the new rules:

- engage additional resources and implement manual processes to achieve compliance; and
- purchase new systems to achieve compliance.

These options were discounted, however, as they would be less effective and introduce greater risk than the changes set out in Accenture's report.

For example, based on actual monthly volumes during 2015, we would be required to process approximately 220,000 separate business-to-business (**B2B**) transactions per year as the default metering coordinator or local network service provider. For the following reasons, managing such volumes through a manual process is not considered a prudent or efficient approach:

- a manual process would compromise our ability to comply with AEMO's B2B procedures.[542] These procedures govern the complex interrelationships between market participants, and include mandated timeframes for both completing works and informing the market that works have been completed (e.g. as the meter data provider, we are required to update market settlement and transfer solutions (**MSATS**) within two days of an actual read where a retailer transfer is pending—based on existing level of transactions, this single process alone would require in excess of 390 manual transactions per day);
- a manual process would introduce significant data integrity issues due to the inherent risk of human error. Data integrity is critical to the efficient operation of market settlement procedures, and any manual process, therefore, would require rigorous data validation processes to identify and remediate erroneous data; and
- in any event, additional resources would limit, but not remove, the need for system and process changes.

An alternative option considered to ensure compliance with the new rules was to purchase entirely new systems. The purchase of new, off-the-shelf systems, however, would not remove the need for remediation to meet our Rules obligations—this is because new systems are typically generic, and still require amendments to meet business specific needs. The capital expenditure required for this option (including training, project management and risk management), therefore, would be additional to the remediation expenditure forecast by Accenture.

[542] AEMO, *B2B procedure, Service order process, version 2.2*, 15 May 2015.

Update for the final rule

Accenture's assessment of the impact of the introduction of metering contestability was substantively finalised in early November. Given the final rule was published in late November, we reviewed Accenture's model to assess whether any amendments were necessary to account for differences between Accenture's assumptions and the final rule.

The final rule published by the AEMC was reasonably consistent with its draft rule and its updated advice published in September 2015. Accordingly, we did not identify any reasons to amend Accenture's estimates.

Victorian Government response to the final rule

The inclusion of our forecast expenditure required as a result of the introduction of metering contestability is based on the assumption the Victorian Government will not extend its jurisdictional derogation regarding advanced metering infrastructure. This derogation is due to expire on 1 December 2017.

Consistent with the above assumption, we have applied zero growth in metering volumes when determining our metering charges. These charges are set out in our metering chapter.

The approach of the Victorian Government, however, remains unclear at this stage. Our metering chapter, therefore, also includes a forecast of expected meter volume growth that should be adopted by the AER if the Victorian Government extends its jurisdictional derogation to 2020.

Importantly, if the Victorian Government does extend its jurisdictional derogation to 2020, our forecast capital expenditure required for the introduction of metering contestability would be deferred, but not avoided—that is, it would still be required, albeit later in the 2016–2020 regulatory control period. In any event, the AER's final determination should adopt consistent assumptions regarding the introduction of metering contestability in Victoria.

8.3 Equity raising costs

Equity raising costs are transaction costs incurred when we raise new equity from outside our business. These costs are forecast separately in the post-tax revenue model (**PTRM**). We agree with the AER's decision to accept the approach to calculating equity raising costs proposed in our regulatory proposal. However, for the purpose of our revised regulatory proposal, we have calculated a revised total equity raising cost on the basis of our revised capital expenditure proposal and therefore reject the allowance for benchmark equity raising costs determined in the AER's preliminary determination.

8.3.1 Initial regulatory proposal

In our regulatory proposal, we proposed total equity raising costs of $2.3 million ($2015), calculated in accordance with the methodology set out in the AER's PTRM.[543]

8.3.2 AER's preliminary determination

In its preliminary determination, the AER accepted our proposed approach for the estimation of equity raising costs and determined an allowance for benchmark equity raising costs of $1.9 million ($2015).[544] The AER calculated our allowance on the basis of the unit inputs used in our regulatory proposal and the revised cash flows resulting from the AER's preliminary determination.[545] The AER noted the allowance for benchmark equity

543 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 96.

544 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-617.

545 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-617.

raising costs may be updated based on the final capital expenditure allowance to be determined by the AER in its final determination in April 2016.[546]

8.3.3 Our revised regulatory proposal

We agree with the AER's decision to accept the approach to calculating equity raising costs proposed in our regulatory proposal. However, for the purpose of our revised regulatory proposal, we have calculated revised total equity raising costs on the basis of our revised capital expenditure proposal (and hence, we reject the allowance for benchmark equity raising costs determined in the AER's preliminary determination).

We propose revised total equity raising costs of $4.9 million ($2015), calculated in accordance with the methodology set out in the AER's PTRM.

8.4 Other non-network

Our forecast of other non-network capital expenditure is split into the following streams:[547]

- motor vehicles—relates to the purchase, replacement or rebuild costs associated with its light and heavy fleet of vehicles;
- property—relates to the provision of office and depot accommodation, buildings and property; and
- other—includes general equipment such as miscellaneous tools and equipment.

8.4.1 Initial regulatory proposal

In our regulatory proposal, we included a forecast of total other non-network capital expenditure for the 2016–2020 regulatory control period equal to $22.9 million ($2015).

8.4.2 AER's preliminary determination

In its preliminary determination, the AER accepted our forecast of total other non-network capital expenditure for the 2016–2020 regulatory control period equal to $22.9 million ($2015).[548]

8.4.3 Our revised regulatory proposal

Consistent with the AER's preliminary determination, our revised regulatory proposal includes a forecast of total other non-network capital expenditure for the 2016–2020 regulatory control period equal to $23.6 million ($2015).[549]

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[546] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-617.

[547] Our regulatory proposal included Supervisory Cables and Data Acquisition (**SCADA**) in our forecast of non-network capital expenditure. The AER, however, assessed SCADA as replacement expenditure in its preliminary determination.

[548] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 6–96.

[549] This differs to our regulatory proposal due to the updated escalation factor.

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9 Opening asset base, depreciation and inflation

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9 Opening asset base, depreciation and inflation

This chapter sets out our revised regulatory proposal in respect of:

- the roll forward of our regulatory asset base (**RAB**) to 1 January 2016;
- the roll forward of our RAB over the 2016–2020 regulatory control period;
- regulatory depreciation; and
- the indexation of our RAB for inflation.

We accept most components of the AER's preliminary determination in relation to the roll forward of our RAB, regulatory depreciation and inflation. Significantly, we accept the AER's decision to adopt a new approach to calculating regulatory depreciation (described by the AER as the 'year-by-year tracking' approach), which we consider represents the most accurate workable method of estimating depreciation.

We do not accept the inflation used to roll forward the RAB to 1 January 2016 and we do not accept the standard life for Victorian Bushfire Royal Commission (**VBRC**) assets.

We also propose an approach for rolling forward the RAB to 1 January 2021 for the purpose of making our distribution determination for the 2021–2025 regulatory control period.

9.1 Rule requirements

The National Electricity Rules (**Rules**) require that the annual revenue requirement for each year of a regulatory control period must be determined using a building block approach. Under the building block approach, the building blocks to be included in a building block proposal relevantly include:

- the return on capital for each regulatory year (clause 6.4.3(a)(2) of the Rules);
- the depreciation for each regulatory year (clause 6.4.3(a)(3) of the Rules); and
- the indexation of the RAB for each regulatory year (clause 6.4.3(a)(1) of the Rules).

The value of the RAB for the relevant regulatory year is an input to the calculation of each of these building blocks (clauses 6.4.3(b)(1), (b)(2) and (b)(3), 6.5.2(a), 6.5.5(a)(1) and S6.2.3(c)(4) of the Rules).

Under the Rules, a distributor's building block proposal must:

- be prepared in accordance with the post-tax revenue model (**PTRM**) published by the Australian Energy Regulatory (**AER**) in accordance with clause 6.4.1 of the Rules (clause 6.3.1(c) of the Rules);
- contain the distributor's calculation of the RAB value for each regulatory year of the relevant regulatory control period using the AER's roll forward model (**RFM**) (clause 6.3.1(c) of the Rules), which is to be accompanied by:
  - details of all amounts, values and other inputs used by the distributor for that purpose (clause S6.1.3(7)(i) of the Rules);
  - a demonstration that any such amounts, values and other inputs comply with the relevant requirements of Part C of Chapter 6 of the Rules (clause S6.1.3(7)(ii) of the Rules); and
  - an explanation of the calculation of the RAB for each year of the relevant regulatory control period and of the amounts, values and inputs referred to above (clause S6.1.3(7)(iii) of the Rules); and
- contain the distributor's completed RFM (clause S6.1.3(10) of the Rules).

The rules and regulatory framework relating to the establishment of the value of the RAB, and the depreciation and RAB indexation building blocks are outlined in turn below.

9.1.1 Regulatory asset base

Clause 6.12.1(6) of the Rules provides that one of the constituent decisions upon which a distribution determination must be predicated is the AER's decision on the RAB as at the commencement of the regulatory control period (in this instance, as at 1 January 2016). The AER's decision is to be made in accordance with clause 6.5.1 and Schedule 6.2 of the Rules.

For a distribution system, the RAB is the value of those assets used by a distributor to provide standard control services, but only to the extent that they are used to provide such services (clause 6.5.1(a) of the Rules).

The AER is required to develop and publish a RFM, which must set out the method for determining the roll forward of the RAB for distribution systems:

- *first*, from the immediately preceding regulatory control period to the beginning of the first year of the subsequent regulatory control period, so as to establish the value of the RAB as at the beginning of the first regulatory year of that subsequent period. This roll forward involves an adjustment for actual inflation in a manner consistent with the method used for the indexation of the control mechanism(s) for standard control services during the preceding regulatory control period (clause 6.5.1(e)(1) and (3) of the Rules); and
- *secondly*, from one regulatory year in a regulatory control period to a subsequent regulatory year in that same regulatory control period, so as to establish the value of the RAB as at the beginning of that subsequent regulatory year (clause 6.5.1(e)(2) of the Rules).

Schedule 6.2 of the Rules sets out specific requirements regarding:

- the establishment of the opening RAB for a regulatory control period (clause S6.2.1 of the Rules); and
- the roll forward of the RAB within the same regulatory control period (clause S6.2.3 of the Rules).

9.1.2 Depreciation

In respect of the depreciation building block, clause 6.4.3(b)(3) of the Rules requires depreciation to be calculated in accordance with clause 6.5.5 of the Rules.

Clause 6.5.5(a) and (b) of the Rules require that:

- the depreciation for each regulatory year must be calculated on the value of the assets as included in the RAB, as at the beginning of that regulatory year, for the relevant distribution system;
- the depreciation for each regulatory year must be calculated using the depreciation schedules for each asset or category of assets nominated in our building block proposal, provided such depreciation schedules conform with clause 6.5.5(b) of the Rules;
- to the extent that the depreciation schedules nominated in our building block proposal do not conform with clause 6.5.5(b) of the Rules, the depreciation for each regulatory year must be calculated using the depreciation schedules determined for that purpose by the AER; and
- clause 6.5.5(b) of the Rules requires that the depreciation schedules must conform to the following requirements:
  - the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets (sub-clause (b)(1));
  - the sum of the real value of the depreciation that is attributable to any asset or category of asset over the economic life of that asset or category of assets (such real value being calculated as at the time the value of that asset or category of assets was first included in the RAB for the relevant distribution system) must

be equivalent to the value at which that asset or category of assets was first included in the RAB for the relevant distribution system (sub-clause (b)(2)); and

  – the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given regulatory control period must be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period (sub-clause (b)(3)).

The AER's PTRM for distributors dated 29 January 2015[550] has been developed on the assumption that straight-line depreciation will be used in developing the depreciation schedules.[551] This is made clear on page 12 of the AER's PTRM handbook (at Appendix D to the PTRM). If a distributor intends to propose other depreciation profiles, the PTRM handbook recommends that this matter be raised as part of pre-lodgement discussions, for example, during the framework and approach process for a determination. The PTRM calculates real straight-line depreciation for each regulatory year by taking the sum of:

- depreciation on the opening RAB, calculated as the opening asset value for the class of asset divided by the remaining life of that class of asset; and
- depreciation on the forecast capital expenditure for each prior regulatory year in the regulatory control period by reference to the standard life for the class of asset. For example:
  – in year 2, this element of depreciation is calculated as forecast capital expenditure in year 1 divided by the standard life for the class of asset; and
  – in year 3, it is calculated as the sum of forecast capital expenditure for years 1 and 2 divided by the standard life for the class of asset.

The remaining life and standard life values referred to above are inputs in the PTRM and the RFM. The RFM handbook (at Appendix C to the RFM) states that the remaining life and standard life values 'must accord with those used in the previous distribution determination'.[552] This is consistent with clause 6.5.5(b)(3) of the Rules. The PTRM handbook indicates that the remaining life of the asset classes is to be based on the economic life of the assets as at the start of the current regulatory control period, which can 'generally … be derived based on the weighted average remaining life of all individual assets in the class', whereas the standard life of the asset classes 'measures how long the infrastructure would physically last had it just been built'.[553]

Clause 6.12.1(18) of the Rules provides that the AER's distribution determination must be predicated on a constituent decision as to whether depreciation for establishing our RAB as at the commencement of the following regulatory control period (in this instance, 2021–2025) is to be based on actual or forecast capital expenditure. This constituent decision must be consistent with the capital expenditure incentive objective (clause S6.2.2B(b) of the Rules), which is 'to ensure that, where the value of a RAB is subject to adjustment in accordance with the Rules, then the only capital expenditure that is included in an adjustment that increases the value of that RAB is capital expenditure that reasonably reflects the capital expenditure criteria' (clause 6.4A(a) of the Rules). Further, clause S6.2.1(e)(5) of the Rules provides that the AER must reduce the previous value of the RAB by the amount of depreciation of the RAB during the previous regulatory control period, calculated in accordance with the distribution determination for that period. That is, in determining the value of the RAB as at

550 AER, *Final decision, Amendment, Electricity transmission and distribution network service providers, Post-tax revenue models (version 3)*, 29 January 2015.

551 AER, *Final decision, Amendment, Electricity distribution network service providers, Post-tax revenue model handbook*, 29 January 2015, p. 12.

552 AER, *Electricity distribution network service providers, Roll forward model handbook*, June 2008, p. 5.

553 AER, *Final decision, Amendment, Electricity distribution network service providers, Post-tax revenue model handbook*, 29 January 2015, p. 13.

1 January 2021, the AER will be bound to apply the approach to depreciation it decided upon in its constituent decision in the immediately previous regulatory control period (in this instance, the AER's 2016–2020 final determination).

9.1.3 Inflation

Clause 6.5.1(c)(3) of the Rules provides that the roll forward of the RAB from the immediately preceding regulatory control period to the beginning of the first regulatory year of a subsequent regulatory control period entails the value of the first mentioned RAB being adjusted for actual inflation, consistently with the method used for the indexation of the control mechanism(s) for standard control services during the preceding regulatory control period.

Clause S6.2.3(c)(4) of the Rules similarly requires that the value of the RAB as at the beginning of the second or a subsequent regulatory year in a regulatory control period must be calculated by adjusting the value of the RAB as at the beginning of the immediately preceding regulatory year in that same period for (amongst other things) inflation, by increasing it by an amount necessary to maintain the real value of the RAB as at the beginning of the first-mentioned regulatory year.

In respect of the RAB indexation building block, clause 6.4.3(b)(1) of the Rules provides that:

- the RAB is to be calculated in accordance with clause 6.5.1 and Schedule 6.2 of the Rules; and
- the RAB indexation building block comprises a negative adjustment to the annual revenue requirement for the relevant regulatory year equal to the amount referred to in clause S6.2.3(c)(4) of the Rules.

9.2 Regulatory asset base

In respect of the roll forward of our RAB to 1 January 2016, we have revised our opening RAB value to reflect:

- our acceptance of the AER’s preliminary decision on equity raising costs; and
- the maintenance of the positions adopted in our regulatory proposal on actual inflation inputs.

In respect of the roll forward of our RAB over 2016–2020, we have revised our opening RAB values for the years 2017 to 2020 (inclusive) and our closing RAB values for each year of the 2016–2020 regulatory control period to reflect:

- our revised 1 January 2016 opening RAB;
- our revised proposed forecast inflation rate for 2016–2020; and
- our revised proposed forecast capital expenditure and forecast regulatory depreciation for the 2016–2020 regulatory control period.

9.2.1 Initial regulatory proposal

Roll forward of the RAB to 1 January 2016

In our regulatory proposal, the estimated value of our RAB for standard control services as at 1 January 2016 was set out in table 13.1.[554] That table is excerpted, for convenience, below.

[554] CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 246.

Table 9.1 Roll forward of the RAB to 1 January 2016 ($ million, nominal)

RAB roll forward	Total
1 January 2010 opening RAB from previous determination	1,218.2
Add: correction for six months of inflation	17.6
Add: estimated/actual net capital expenditure for 2010-15	871.4
Add: difference between actual and estimated capital expenditure in 2010	-23.2
Add: return on difference between 2010 actual and estimated capital expenditure	-13.3
Less: actual straight line depreciation for 2011–2015	-472.0
Add: adjustment for actual inflation	206.1
1 January 2016 opening RAB	**1,804.7**

Source: CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 246

The 1 January 2016 opening RAB was calculated using the AER's RFM.[555] Importantly, in calculating the estimated value of the RAB:

- for the reasons, and in accordance with the method, set out in CP PUBLIC ATT 13.2 – CitiPower, *Six month inflation correction*, April 2015, we implemented a six-month inflation correction;
- depreciation based on actual capital expenditure was deducted in accordance with the AER's 2011–2015 final determination; and
- we made an adjustment for actual inflation, consistent with the method used for the indexation of the control mechanism applicable in the 2011–2015 regulatory control period.

Roll forward of the RAB over 2016–2020

The opening RAB was then rolled forward over the 2016–2020 regulatory control period in accordance with the Rules, using the AER's PTRM.[556]

In rolling forward the opening RAB, we separated out one new asset class from the classes used in the AER's 2011–15 Final Determination, namely supervisory cables, which will become redundant by December 2020. The reasons for separating out that asset class are set out in our regulatory proposal.[557]

In our regulatory proposal, the roll forward of the RAB over 2016–2020 was set out in table 13.2.[558] That table is excerpted, for convenience, below.

555 CitiPower, *CP PUBLIC MOD 1.9 – CP 2011-15 RFM*.

556 CitiPower, *CP PUBLIC MOD 1.10 – CP 2016-20 PTRM*.

557 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 246.

558 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 247.

Table 9.2 Roll forward of the RAB over 2016–2020 ($ million, nominal)

RAB roll forward	2016	2017	2018	2019	2020
Opening RAB	1,804.7	1,934.4	2,098.6	2,246.9	2,365.3
Forecast net capital expenditure	181.4	215.5	206.1	183.1	149.7
Depreciation	98.7	101.6	112.3	123.1	133.3
Inflation on opening RAB	46.9	50.3	54.6	58.4	61.5
Closing RAB	**1,934.4**	**2,098.6**	**2,246.9**	**2,365.3**	**2,443.2**

Source: CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 247

There were no forecast disposals for the purpose of clause S6.2.3(c)(3) of the Rules.

Forecast net capital expenditure included in the roll forward of the RAB over 2016–2020 replicated the forecasts of net capital expenditure set out in table 9.1 of our regulatory proposal,[559] with one noteworthy exception: the figures in the above tables are expressed in nominal terms, whereas the figures in table 9.1 of our regulatory proposal were expressed in real terms and did not include half a year's weighted average cost of capital.

Depreciation approach in roll forward of the RAB to 1 January 2021

In our regulatory proposal, we proposed to use depreciation based on forecast capital expenditure in establishing the RAB as at the commencement of the 2021–2025 regulatory control period.[560]

9.2.2 AER's preliminary determination

Roll forward of the RAB to 1 January 2016

In Attachment 2 to the preliminary determination, the AER did not accept our proposed opening RAB value of $1,804.7 million ($nominal).[561] Instead, the AER determined an opening RAB value of $1,795.1 million ($nominal), which represents a reduction of $9.7 million ($nominal) or 0.5 per cent.[562]

In reaching its decision, the AER reviewed the key inputs of our proposed RFM, such as asset lives, actual gross capital expenditure, capital contributions and rate of return, and found that they were correct and reconciled with relevant data.[563] However:

- the AER made adjustments to our proposed RFM inputs for actual inflation and equity raising costs; and
- having accepted that our proposed six-month inflation correction was appropriate, the AER nevertheless rejected our proposed approach to indexing the RAB for the additional half year of inflation.[564]

In respect of the AER's adjustment for equity raising costs, the AER rejected our proposed value of equity raising costs included in 2011 capital expenditure of $3.2 million ($nominal) on the basis that the AER's RFM requires the input of capital expenditure in nominal mid-year dollar terms.[565] In the AER's view, our proposed value of

559 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 96.

560 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 185.

561 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-6.

562 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-6.

563 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-13.

564 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-6.

565 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-14.

equity raising costs included an incorrect adjustment of inflation, which converted the value of equity raising costs capital expenditure from real 2010 to nominal 2011 dollar terms.[566] The AER determined that only six months of inflation was required to convert the equity raising costs to a nominal mid-year value as required by the RFM, which equated to revised equity raising costs of $2.8 million ($nominal).[567]

The AER's preliminary decision on the roll forward of our RAB to 1 January 2016 was set out in table 2.1 of the AER's preliminary determination.[568]

Roll forward of the RAB over 2016–2020

In Attachment 2 to the preliminary determination, the AER did not accept our proposed closing RAB value of $2,443.2 million ($nominal).[569] Instead, the AER determined a closing RAB value of $2,210.3 million ($nominal), which represents a reduction of $232.9 million ($nominal) or 9.5 per cent.[570]

In reaching its decision, the AER amended four inputs to the AER's PTRM:[571]

- our opening RAB value was reduced by 0.5 per cent;
- our proposed forecast inflation rate of 2.60 per cent per annum was reduced by 0.1 per cent, for the reasons set out in Attachment 3 to the AER's preliminary determination;
- our proposed forecast net capital expenditure for the 2016–2020 regulatory control period was reduced by $216.0 million ($nominal) or 23.1 per cent, for the reasons set out in Attachment 6 to the AER's preliminary determination (discussed in chapter 7). Included in that figure is an offset of $1.3 million ($nominal) for disposals; and
- our proposed forecast regulatory depreciation for the 2016–2020 regulatory control period was increased by $7.3 million ($nominal) or 2.6 per cent, for the reasons set out in Attachment 5 to the AER's preliminary determination.

As the above amendments make clear, the main driver of the reduction in our closing RAB value was the AER's reduction in our proposed forecast capital expenditure for the 2016–2020 regulatory control period.

The AER's preliminary decision on the roll forward of our RAB over 2016–2020 was set out in table 2.2 of the AER's preliminary determination.[572]

Depreciation approach in roll forward of the RAB to 1 January 2021

In Attachment 2 to the preliminary determination, the AER accepted our forecast depreciation approach to the roll forward of the RAB to 1 January 2021.[573] The AER was satisfied that the use of a forecast depreciation approach in combination with its application of the capital efficiency sharing scheme (**CESS**) in the 2016–2020 regulatory control period and other ex post capital expenditure measures will be sufficient to achieve the capital expenditure incentive objective.[574]

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566 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-14.

567 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, pp. 2-14 to 2-15.

568 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-7.

569 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-15.

570 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-15.

571 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, pp. 2-15 to 2-16.

572 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-7.

573 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-16.

574 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-16.

9.2.3 Our response to the AER's preliminary determination

We have amended the value of equity raising costs included in our 2011 capital expenditure to reflect the revised equity raising costs of $2.8 million ($nominal) set out in the AER's preliminary determination.

9.2.4 Our revised regulatory proposal

Roll forward of the RAB to 1 January 2016

We have amended the estimated value of our RAB for standard control services as at 1 January 2016 as set out in table 9.3 below.

Table 9.3 Roll forward of the RAB to 1 January 2016 ($ million, nominal)

RAB roll forward	Total
1 January 2010 opening RAB from previous determination	1,218.2
Add: estimated/actual net capital expenditure for 2010-2015	869.2
Add: difference between actual and estimated capital expenditure in 2010	-21.4
Add: return on difference between 2010 actual and estimated capital expenditure	-12.2
Less: actual straight line depreciation for 2011–2015	-470.1
Add: adjustment for actual inflation	203.3
Add: correction for six months of inflation	15.7
1 January 2016 opening RAB	**1,802.6**

Source: CitiPower

Roll forward of the RAB over 2016–2020

We have amended the roll forward of the RAB over 2016–2020 as set out in table 9.4 below.

Table 9.4 Roll forward of the RAB over 2016–2020 ($ million, nominal)

RAB roll forward	2016	2017	2018	2019	2020
Opening RAB	1,802.6	1,923.1	2,078.6	2,212.9	2,318.0
Forecast net capital expenditure	178.8	213.5	196.9	172.0	138.4
Depreciation	103.3	106.1	114.5	122.2	130.7
Inflation on opening RAB	45.1	48.1	52.0	55.3	58.0
Closing RAB	**1,923.1**	**2,078.6**	**2,212.9**	**2,318.0**	**2,383.6**

Source: CitiPower

9.3 Depreciation

We accept the preliminary decision to adopt, and hence propose in our revised regulatory proposal, the base-line method or 'year-by-year tracking' approach to calculating regulatory depreciation. In addition, we set out our proposed approach to determining forecast regulatory depreciation for the 2016–2020 regulatory control period for the purpose of rolling forward our RAB from 2016 to 2021 at the next reset.

9.3.1 Initial regulatory proposal

In our regulatory proposal, we calculated the depreciation of the RAB using the straight-line depreciation method. In accordance with that method:

- opening asset values as at 1 January 2016 were divided by the remaining lives; and
- new assets (forecast net capital expenditure for the 2016–2020 regulatory control period) were divided by standard lives.

In our regulatory proposal, our proposed standard asset lives and remaining asset lives were set out in table 13.3.[575] That table is excerpted, for convenience, below.

Table 9.5 Standard and remaining asset lives (years)

Asset	Standard life	Remaining life
Sub-transmission	50.0	30.5
Distribution system assets	49.0	20.8
Standard meeting	-	1.1
Public lighting	-	8.3
SCADA/Network control	13.0	7.7
Non-network general assets – IT	6.0	5.5
Non-network general assets – Other	10.0	7.4
Victorian Bushfires Royal Commission	20.8	-
Equity raising	43.0	42.6
Supervisory cables	-	5.0

Source: CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 248

Standard asset lives were set equivalent to the standard lives in the current regulatory control period, as determined by the AER.

In our regulatory proposal, our calculation of 1 January 2016 remaining asset lives was set out in CP PUBLIC MOD 1.9 – *CP 2011-15 RFM*. We departed from the AER's 'preferred' method for calculating remaining asset life values and, instead, proposed the 'direct method' of calculating the remaining life values to be input to the AER's PTRM.[576] Our proposed 'direct method' calculated the annual depreciation for the next period under a straight-line depreciation method directly by reference to asset and capital expenditure values, and remaining and standard life values respectively, in the current period.[577]

In respect of the new asset class that we separated out from the classes used in the AER's 2011–2015 final determination, supervisory cables, which will become redundant by December 2020, were fully depreciated in

[575] CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 248.

[576] CitiPower, *Regulatory proposal 2016–2020*, April 2015, appendix K, p. 9.

[577] CitiPower, *Regulatory proposal 2016–2020*, April 2015, appendix K, pp. 10 to 11.

2020. Our calculation of the depreciated value of supervisory cables was set out in CP PUBLIC MOD 1.41 – *Supervisory cables opening asset value*.[578]

In our regulatory proposal, regulatory depreciation for each year of the 2016–2020 regulatory control period was set out in table 13.4.[579] That table is excerpted, for convenience, below.

Table 9.6 Regulatory depreciation ($ million, nominal)

	2016	2017	2018	2019	2020
Straight-line depreciation	98.7	101.6	112.3	123.1	133.3
Inflation adjustment	46.9	50.3	54.6	58.4	61.5
Regulatory depreciation	**51.8**	**51.3**	**57.8**	**64.7**	**71.8**

Source: CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 248

9.3.2 AER's preliminary determination

In Attachment 5 to the AER's preliminary determination, the AER accepted our proposed straight-line depreciation method for calculating the regulatory depreciation allowance.[580]

The AER accepted our proposed asset classes, yet included an additional 'Land' asset class on the basis that land is generally considered to be a non-depreciable asset and should therefore not be assigned a standard asset life (i.e. a standard asset life of 'n/a' for modelling purposes).[581] The AER also accepted our proposed standard asset life values, with the exception of our proposed standard asset life for the 'VBRC' asset class. The AER set the standard asset life for the 'VBRC' asset class at 49 years, equal to the standard asset life of our 'Distribution system assets' class.[582]

The AER did not accept our proposed approach for calculating remaining asset lives at 1 January 2016.[583] Instead, the AER applied a new approach – the 'year-by-year tracking' approach – to determine the depreciation of existing assets that is consistent with our submission in response to the AER's issues paper dated 10 June 2015 and endorsed by Incenta Economic Consulting (**Incenta**).[584]

Under the year-by-year tracking approach, the capital expenditure for each year of a regulatory control period will be depreciated separately, with each asset class having an expanding list of sub-classes to reflect every regulatory year in which capital expenditure on those assets was incurred. In the AER's view, the year-by-year tracking approach:[585]

- produces depreciation schedules that reflect the nature of the assets and their economic life, in accordance with clause 6.5.5(b)(1) of the Rules; and

578 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 247.

579 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 248.

580 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 5-11.

581 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 5-11.

582 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, pp. 5-11 to 5-12.

583 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 5-14.

584 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, pp. 5-14 to 5-15. See also: AER, Issues Paper, Victorian electricity distribution pricing review, 2016 to 2020, June 2015 (**AER Issues Paper**); CitiPower and Powercor, *Submission in response to the issues paper, Depreciation*, 13 July 2015; and Incenta, *Calculation of straight line depreciation – review of the AER's approximate calculation: CitiPower, Powercor and Jemena Electricity Networks,* July 2015.

585 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 5-15.

- ensures that total depreciation (in real terms) equals the initial value of the assets, in accordance with clause 6.5.5(b)(2) of the Rules.

With a view to minimising issues arising from the change in approach to calculating remaining asset lives, the AER accepted our proposal for the remaining asset lives for existing assets as at 1 January 2011 to reflect those values approved in the AER's 2011–15 final determination.[586]

The AER also accepted our proposal to accelerate the depreciation of one specific asset class, namely 'supervisory cables'.[587]

9.3.3 Our response to the AER's preliminary determination

In respect of standard asset lives, we have amended our proposal such that:

- the 'VBRC' asset class has been divided into two types of assets, namely:
  - armour rods, vibration dampers and spacers, which will remain allocated to the 'VBRC' asset class and depreciated over 25.6 years, consistent with the depreciation period stipulated in Powercor's VBRC pass-through application;[588] and
  - remaining assets, which will be allocated to the 'Distribution system assets' asset class and depreciated over 49 years in accordance with the AER's preliminary determination; and
- capital expenditure relating to land has been allocated to an additional 'Land' asset class and has not been assigned a standard asset life (i.e. it has been assigned with the term 'n/a' for modelling purposes), in recognition of the fact that land is generally considered to be a non-depreciable asset.

In accordance with our response to the AER's Issues Paper, we endorse the AER's decision and now propose to calculate regulatory depreciation using the 'base-line' method (or 'year-by-year tracking' approach, as it is referred to in the AER's preliminary determination). We consider that this approach, by keeping track of depreciation on each year's capital expenditure for each asset class, represents the most accurate method of estimating depreciation. As outlined by Incenta,[589] and reiterated in our response to the AER's Issues Paper,[590] the base-line method is to be preferred to the AER's WARL method.

For the reasons set out in the AER's preliminary determination, and in the Incenta Report and our response to the AER's Issues Paper,[591] we agree with the AER that the base-line method is consistent with the requirements set out in clause 6.5.5(b) of the Rules. Further, by ensuring that assets are depreciated in a manner that reflects their economic life, the base-line method safeguards against the intergenerational equity issues previously acknowledged by the AER.[592]

It follows from our proposal of the base-line method for the calculation of depreciation for the 2016–2020 regulatory control period and the conformance of that method with the requirements of clause 6.5.5(b) of the

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[586] AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 5-16.

[587] AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 5-22.

[588] Powercor, *Pass through application: response to 2009 Victorian Bushfire Royal Commission as included in revised ESMS of 10 August 2011*, 12 December 2011, p. 4.

[589] Incenta, *Calculation of straight line depreciation – review of the AER's approximate calculation: CitiPower, Powercor and Jemena Electricity Networks*, July 2015.

[590] CitiPower and Powercor, *Submission in response to the issues paper, Depreciation*, 13 July 2015, pp. 5 to 6.

[591] CitiPower and Powercor, *Submission in response to the issues paper, Depreciation*, 13 July 2015, pp. 5 to 6.

[592] See, for example, the AER's discussion in *AER, Preliminary Decision, SA Power Networks determination 2015-16 to 2019-20*, Attachment 5 – Regulatory depreciation, April 2015, p. 5-13.

Rules (which conformance is accepted by the AER) that, in making the final decision, the AER is required by clause 6.5.5(a)(2)(i) of the Rules to use the base-line method in calculating depreciation.

In the context of discussing its acceptance of our year-by-year tracking approach to determine forecast depreciation for the 2016–2020 regulatory control period, the AER observed in its preliminary determination that:[593]

> *…with the adoption of forecast depreciation, we are proposing to extend the WARL to be calculated based on year-by-year tracking of remaining asset lives. This approach will still provide an average remaining asset life and therefore can still lead to different outcomes than separately depreciating asset sub-classes. However, it will improve the precision of the remaining asset lives over time as more asset sub-classes are added.*

In making these observations in its preliminary determination, the AER referred to the discussion in section 4.3 of its *Explanatory statement Proposed amendment Electricity transmission network service providers Roll forward model (version 3)*, July 2015, of the calculation of remaining asset lives using the WARL approach for the purposes of calculating forecast depreciation for use in rolling forward the RAB from one regulatory control period to the next.[594]

It is not clear to us from the AER's preliminary determination how the AER proposes to determine depreciation in the 2016–2020 regulatory control period for the purposes of rolling forward the RAB from 2016 to 2021 in making our distribution determination for the 2021–2025 regulatory control period. Accordingly, we discuss below our proposed approach to determining depreciation for 2016–2020 for the purposes of rolling forward the RAB to 2021.

Our proposed approach to the roll forward of the RAB from the start of 2016 to the end of 2020 applies forecast straight-line depreciation based on forecast capital expenditure (rather than actual capital expenditure) for 2016–2020 (consistent with our proposal, accepted by the AER in its preliminary determination, that forecast depreciation will be used to roll forward the RAB over the 2016–2020 regulatory control period).

Our proposed approach to the roll forward of the RAB from the start of 2016 to the end of 2020 is illustrated in CP PUBLIC RRP MOD 1.12 - *CP 2016-20 illustration of RAB roll forward.xlsm*. As that illustrative model demonstrates, our proposed approach contemplates that the real forecast straight-line depreciation (expressed in December 2015 dollar terms) for each year of that period and for each asset class set out in the 'Assets' worksheet in the AER's PTRM to accompany the final determination for 2016–2020, is input into the AER's RFM to accompany its final determination for 2021-2025. The 2016–2020 capital expenditure and inflation inputs into the illustrative model have been set equal to those in the PTRM to provide a check that the final 2020 closing RAB in the illustrative model is equal to that in the PTRM. These will need to be updated with actual capital expenditure and inflation.

We note that the check that the final 2020 closing RAB in the illustrative model is equal to that in the PTRM is only satisfied if the inflation error mentioned in this section is corrected in the RFM.

We agree with the AER's decision, consistent with our regulatory proposal, to accelerate the depreciation of the new 'Supervisory cables' asset class and accept our proposed value for that asset class as at 1 January 2016.

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593 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 5-20.

594 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 5-20, footnote 62.

9.3.4 Our revised regulatory proposal

We have amended the standard asset life values as set out in table 9.7 below.

Table 9.7 Standard asset lives (years)

Asset	Standard life
Sub-transmission	50.0
Distribution system assets	49.0
Standard meeting	n/a
Public lighting	n/a
SCADA/Network control	13.0
Non-network general assets – IT	6.0
Non-network general assets – Other	10.0
Victorian Bushfire Royal Commission	25.6
Equity raising	42.4
Supervisory cables	n/a
Old SWER ACRs	n/a

Source: CitiPower

We maintain our position, accepted by the AER in its preliminary determination, that remaining asset lives for existing assets as at 1 January 2011 reflect those values approved in the AER's 2011–15 final determination.

We have amended our proposed regulatory depreciation for each year of the 2016–2020 regulatory control period as shown in table 9.8 below.

Table 9.8 Regulatory depreciation ($ million, nominal)

	2016	2017	2018	2019	2020
Straight-line depreciation	103.3	106.1	114.5	122.2	130.7
Inflation adjustment	45.1	48.1	52.0	55.3	58.0
Regulatory depreciation	**58.2**	**58.0**	**62.6**	**66.9**	**72.8**

Source: CitiPower

9.4 Inflation

In respect of actual inflation inputs, we do not accept the AER's preliminary decision and maintain the position in our regulatory proposal. We accept the AER's approach to indexing our RAB for an additional half year of inflation, which is required to rectify the fundamental error made by the AER in approaching the indexation of our 2011 opening RAB for inflation. However, we maintain our approach to determining the forecast inflation input to the PTRM and accept the AER's updated estimate of that input.

9.4.1 Initial regulatory proposal

Actual inflation inputs to RFM

In our regulatory proposal, consistent with the method used for the indexation of the control mechanism applicable in the 2011–2015 regulatory control period, we adjusted the RAB for actual inflation in rolling forward the RAB to 1 January 2016.

Furthermore, in the attachment to our regulatory proposal titled CP PUBLIC ATT 13.2 – CitiPower, Six month inflation correct, April 2015, we set out why and how we calculated a six-month inflation correction, a correction designed to address a fundamental error made by the AER in approaching the indexation of the 2011 RAB for inflation (see the Tribunal's reasoning in *Application by United Energy Distribution Pty Limited (No 1)* [2012] ACompT 1 (**Application by UED**) at [338] to [386]). Specifically, we proposed that:[595]

- in determining the 1 January 2016 opening RAB value for the purpose of the 2016–2020 distribution determination, the AER must apply five and a half years of inflation to the 1 January 2011 RAB value determined by the AER in its 2011–15 final determination; and
- in order to index the 2011 opening RAB value for six months of inflation in rolling forward that value to 1 January 2016 (i.e. so that it is stated in 1 January 2011, rather than 1 July 2010, dollar terms), the inputs to the AER's opening RAB value be indexed as follows:
  - first, the 2010 opening RAB value be indexed for the six-month indexation period 1 July 2010 to 1 January 2011 prior to the roll forward of that 2010 opening RAB value in accordance with the AER's RFM;
  - secondly, prior to the adjustment of the forecast amounts for capital expenditure and depreciation in the final year of the preceding regulatory control period (i.e. 2010) for the difference between those forecast amounts and the actual amounts for capital expenditure and depreciation in 2010 being made in accordance with the AER's RFM:
    - the forecast amounts for 2010 in the AER's PTRM accompanying the AER's 2011–2015 final determination be indexed for 6 months of inflation, as those forecasts are otherwise assumed to be stated in mid-year dollars (i.e. 1 July 2010 dollars);
    - the actual amounts for 2010 to be input into the AER's RFM completed for 2016–2020 be indexed for 6 months inflation, rather than a half year's nominal WACC being applied to those amounts as would otherwise occur in the AER's RFM; and
  - thirdly, the roll forward of the 2011 opening RAB value be otherwise indexed in accordance with the AER's RFM.

We further proposed that the 1 January 2011 opening RAB value (stated in 1 July 2010 dollar terms) be indexed for five and a half years of inflation by reference to March 2009 to September 2014 Consumer Price Index (**CPI**).[596] That is:

- prior to the roll forward of that 2011 opening RAB value in accordance with the AER's RFM, the 2011 opening RAB value (presently stated in 1 July 2010 dollar terms) be indexed for the six-month indexation period from 1 July 2010 to 1 January 2011 by reference to March 2009 to September 2009 CPI; and

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595 CP PUBLIC ATT 13.2 – *CitiPower, Six month inflation correct,* April 2015, pp. 9 to 10 and 11.

596 CP PUBLIC ATT 13.2 – *CitiPower, Six month inflation correct,* April 2015, p. 12.

- in determining the 1 January 2016 opening RAB value by rolling forward the 1 January 2011 opening RAB value (now, after the previous step, stated in 1 January 2011 dollars terms) in accordance with the AER's RFM, the 1 January 2011 opening RAB value be indexed for inflation by reference to September 2009 to September 2014 CPI.

This proposed approach adopts a 15-month lagged proxy measure of inflation in indexing the 2011 opening RAB value for inflation, consistent with the requirements of clause 6.5.1(e)(3) of the Rules.

Forecast inflation rate input to PTRM

In summary, in our regulatory proposal, we proposed to adopt the AER's current approach to determining the expected rate of inflation input to the PTRM.[597] However, our proposal was caveated in that it acknowledged the apparent volatility in expectations concerning inflation in Australia and globally, and noted that the best approach to determining the expected rate of inflation may evolve during the period in which our proposal is considered by the AER.[598]

9.4.2 AER's preliminary determination

Actual inflation inputs to RFM

In the AER's preliminary determination, the AER determined that we did not apply the 'established approach' for recording actual CPI inflation rates in our proposed RFM. The established approach is to apply a one-year lagged inflation rate to net capital expenditure and straight-line depreciation consistent with the method of indexation used in the control mechanism. In the AER's view, each actual CPI inflation rate is to be recorded in the RFM in the year related to its measure (i.e. un-lagged) (with September quarter CPI used as the proxy for the calendar year for the 2011–2015 regulatory control period and June quarter CPI used as the proxy for the calendar year for the 2016–2020 regulatory control period) because the RFM itself converts the actual observations into a one-year lagged index for use in the RAB roll forward process.

On that basis, the AER applied the above approach to RAB indexation and, in doing so, replaced our one-year lagged CPI observations such that they are recorded in the RFM in the year related to their measure. The AER accepted our use of a CPI estimate for 2015, given that actual inflation for 2015 is presently unknown; however, the AER's final decision will update this estimate for actual 2015 inflation.

Indexation of the opening RAB at 1 January 2011

In the AER's preliminary determination, the AER:[599]

- acknowledged that the opening RAB value as at 1 January 2011 approved in our 2011–2015 final determination was obtained by escalating the opening RAB value as at 1 January 2006 (expressed in July 2004 dollar terms) using inflation data for six years; and
- accepted that it made an error in indexing the opening RAB value as at 1 January 2011, such that there remains a discrepancy requiring a six-month inflation correction as proposed in our regulatory proposal.

However, the AER rejected our proposed approach to implementing the required six-month inflation correction. Instead, the AER considered that the appropriate approach is to calculate the opening RAB value as at 1 January 2011 that would have resulted had the AER adjusted our RAB in the 2011–2015 distribution

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597 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 240.

598 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 240.

599 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-15.

determination process.[600] That adjustment to the RAB value is the difference between the new calculated RAB value as at 1 January 2011 and the value approved in our 2011–2015 final determination, which equates to $15.7 million ($nominal) and is added to the closing RAB value as at 31 December 2015.[601] The AER's alternative approach leads to a reduction of $1.9 million ($nominal) as compared our proposed adjustment of $17.6 million ($nominal).[602]

Forecast inflation rate input to PTRM

In summary, in the AER's preliminary determination, the AER accepted our proposed method for forecasting inflation for the 2016–2020 regulatory control period. However, the AER updated our proposed inflation estimate to reflect the most recent Reserve Bank of Australia (**RBA**) forecasts (i.e. as at October 2015), and stated that it would further update the forecast inflation rate with a more recent inflation forecast published by the RBA in making its final decision.[603]

The AER's reduction of the forecast inflation rate affects, amongst other things, the indexation of the RAB for inflation (in establishing the RAB value for the second or a subsequent regulatory year in the 2016–2020 regulatory control period by rolling forward the RAB to that regulatory year from the immediately preceding regulatory year in that period) and, thus, also the RAB indexation building block.

9.4.3 Our response to the AER's preliminary determination

Actual inflation inputs to RFM

We do not accept the AER's approach to the recording and use of actual inflation inputs in the RFM for use in RAB indexation. We maintain our proposal that the RFM should index the RAB for inflation in year t using the actual CPI inflation measure in year t-1 (i.e. the annual change in CPI from the September quarter in year t-2 to the September quarter in year t-1 for the 2011–2015 regulatory control period and the annual change in CPI from the June quarter in year t-2 to the June quarter in year t-1 for the 2016–2020 regulatory control period). We further maintain that the same measure of inflation should be used in performing real to year t nominal dollar conversions of net capital expenditure and depreciation in the RFM, and our revised proposal modifies the RFM to effect this result.

Whereas we proposed to input the actual CPI inflation rate for year t-1 in the RFM for year t (which the AER referred to in its preliminary determination as a 'one year lagged observation'), the AER instead maintained in its preliminary determination that the actual CPI inflation rate for year t should be input in the RFM for year t (referred to by the AER as an 'un-lagged' observation), with September quarter CPI used as a proxy for the calendar year in the 2011–2015 regulatory control period and June quarter CPI used as a proxy for the calendar year in the 2016–2020 regulatory control period (consistent with the CPI observations used in the indexation of the control mechanism in the respective periods). By way of explanation, the AER observed that:

> *… the RFM requires each actual CPI rate measured for a year to be recorded in that specific year (un-lagged). These actual observations are converted as part of coding within the RFM into a one year lagged index for use in the RAB roll forward process.*

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600 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-15.

601 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 2-15.

602 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 246.

The AER further asserted that, by contrast, our approach 'results in the RAB being adjusted by a two year lagged inflation index' and that this is not consistent with clause 6.5.1(e)(3) of the Rules.[604]

It is difficult to reconcile these observations by the AER with what occurs in the AER's published RFM. In that RFM, the actual CPI inflation rates input in the RFM for year t are used in indexing the RAB for inflation for year t. By contrast, as a consequence of the coding in the RFM that lags by one year the actual CPI inflation rates input used in the RFM for real to nominal year t dollar conversions, the actual CPI inflation rate input in the RFM for year t-1 is used in those conversions. It follows that, pursuant to the AER's approach, if actual CPI inflation rates for year t are input in the RFM for year t, the actual inflation rates used in indexing the RAB for inflation in year t will be those for year t.

This is problematic for three reasons:

- first, the AER's approach, being to input in the RFM for year t the actual CPI inflation rate for year t, renders the AER's indexation of the RAB for inflation non-compliant with clause 6.5.1(e)(3) of the Rules;
- secondly, the AER's approach results in a discontinuity in the indexation of our RAB for inflation, specifically our RAB is, under the AER's approach, never being indexed for the annual change in CPI from the September quarter in 2009 to the September quarter in 2010; and
- thirdly, the AER's published RFM results in an inconsistent treatment of inflation as between the indexation of the RAB and real to nominal dollar conversions of net capital expenditure and depreciation.

Clause 6.5.1(e)(3) of the Rules requires that the roll forward of the RAB to the commencement of a regulatory control period entail an adjustment for actual inflation in a manner consistent with the method used for the indexation of the control mechanism for standard control services during the preceding regulatory control period.

The control mechanism for standard control services applying in the 2011–2015 regulatory control period required that pricing for year t be indexed for inflation using the annual percentage change in CPI from the September quarter in year t-2 to the September quarter in year t-1.[605] Similarly, in Attachment 14 to its preliminary determination, the AER determined that the control mechanism for standard control services to be applied in the 2016–2020 regulatory control period will require pricing for year t to be indexed for inflation using the annual percentage change in CPI from the June quarter in year t-2 to the June quarter in year t-1.[606]

It is the consistency of the indexation of the RAB for inflation in rolling forward that RAB from one regulatory control period to the next (and not the consistency of real to nominal dollar conversions for net capital expenditure and depreciation) with the method used for indexation of the control mechanism in the preceding period with which clause 6.5.1(e)(3) of the Rules is concerned. Thus, compliance with clause 6.5.1(e)(3) of the Rules requires that the RAB be indexed for inflation in year t using:

- for the 2011–2015 regulatory control period, the annual percentage change in CPI from the September quarter in year t-2 to the September quarter in year t-1; and
- for the 2016–2020 regulatory control period, the annual percentage change in CPI from the June quarter in year t-2 to the June quarter in year t-1.

The AER appears to acknowledge as much in its preliminary determination in asserting that our approach is not consistent with that provision as it results in the RAB being adjusted by a *two-year lagged* inflation index. Yet, the

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[604] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 2-14, see footnotes 33 and 34.

[605] AER, *Final decision, Victorian distribution determination final decision 2011–2015*, 29 October 2015, p. 57.

[606] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 14-14.

result of its approach to inputting actual CPI inflation rates to the RFM is the application of the annual percentage change in CPI from the September quarter in year t-1 to the September quarter in year t.

It follows that, as we originally proposed, actual CPI inflation rates for year t-1 (that is, the annual change in CPI from the September quarter in year t-2 to the September quarter in year t-1) must be input to the RFM for year t, if, in rolling forward the RAB to 1 January 2016, that RAB is to be indexed for inflation consistently with the indexation of the control mechanism for inflation in 2011–2015 as is required by clause 6.5.1(e)(3) of the Rules.

Further, the AER's approach in the preliminary determination to indexation of the RAB in the roll forward to 2016 differs from the approach it adopted in indexing the RAB for inflation in the roll forward to 2011 in its 2011–2015 final determination (in which the AER did not use its published RFM but rather a Victorian Distribution Network Service Provider (**DNSP**) specific RFM published contemporaneously with that distribution determination). As a result, there is a discontinuity in the CPI inflation rate series applied in indexing our RAB for inflation.

Specifically, under the AER's approach, our RAB is never indexed for the annual change in inflation from the September quarter in 2009 to the September quarter in 2010, being 2.79 per cent. That is:

- in our distribution determination for the 2011–2015 regulatory control period, the last annual actual CPI rate used by the AER in indexing our RAB for inflation in rolling that RAB forward to 1 January 2011 was the change in CPI from the September quarter in 2008 to the September quarter in 2009, being 1.26 per cent;[607] but
- in the AER's preliminary determination, the first annual actual CPI rate used by the AER in indexing our RAB for inflation in rolling that RAB forward to 1 January 2016 (that is, in indexing the RAB for inflation in 2011) is the change in CPI from the September quarter in 2010 to the September quarter in 2011, being 3.52 per cent.

The difference between our approach and that of the AER to indexing the RAB for inflation in rolling forward the RAB to 1 January 2016 is illustrated in table 9.9.

[607] AER, *Final decision, CitiPower distribution determination 2011–2015*, October 2010, CitiPower RFM Final Decision, worksheet titled 'Actual Data Inputs', cell H10.

Table 9.9 RAB indexation – inflation rate applied to opening RAB

	Proposal		Preliminary determination	
	CPI	Rate	CPI	Rate
2009[608]	Sept 07 – Sept 08	4.98%	Sept 07 – Sept 08	4.98%
2010[609]	Sept 08 – Sept 09	1.26%	Sept 08 – Sept 09	1.26%
2011	Sept 09 – Sept 10	2.79%	Sept 10 – Sept 11	3.52%
2012	Sept 10 – Sept 11	3.52%	Sept 11 – Sept 12	2.00%
2013	Sept 11 – Sept 12	2.00%	Sept 12 – Sept 13	2.16%
2014	Sept 12 – Sept 13	2.16%	Sept 13 – Sept 14	2.31%
2015	Sept 13 – Sept 14	2.31%	Sept 14 – Sept 15	1.50%
2011–2015	-	**13.44%**	-	**12.03%**

Source: CitiPower

Finally, as a consequence of the coding in the RFM that lags actual inflation inputs used for the real to nominal conversion by one year, but does not lag the inflation inputs to inflate the opening RAB, the AER's 'established approach' treats actual inflation inputs inconsistently within the RFM. The AER's preliminary determination does not explain any clear rationale necessitating the internally inconsistent treatment of actual inflation inputs.

That the internally inconsistent treatment of actual inflation inputs involves error becomes evident upon examination of the depreciation model accompanying the AER's preliminary determination.[610] In the 'Inputs' worksheet in that model, the AER has adopted inflation rates and inflation escalators for the years 2010 to 2015 in cells I17:N17 and I18:N18 equivalent to those used in cells G177:L177 and G178:L178 in the 'Input' worksheet in the AER's RFM. Consequently, when the AER calculates the sum of depreciation for each asset class from 2016 to 2070, there is a resultant mismatch between the sum of depreciation for each asset class and the 2016 opening RAB value for that asset class. The AER's ad hoc solution to this mismatch is to implement a 'required' adjustment,[611] which serves to equate the sum of depreciation for each asset class with the corresponding closing RAB value of that asset class.[612]

We therefore consider that the AER's published RFM embodies a manifest error in that the inflation measure used in indexing the RAB for inflation in year t is lagged by one year when it is used for real to nominal year t dollar conversions. This issue cannot be remedied by means of the selection of actual CPI inflation rates inputs to the RFM, as it is a product of the RFM's coding. Rather, it must be remedied by modifying the AER's published RFM and, accordingly, we propose a modification to render consistent the inflation measures used in the RFM for each of the indexation of the RAB for inflation and the real to nominal dollar conversions of net capital expenditure and depreciation. As a result of our proposed modification:

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608 This shaded row reflects the AER's approach to indexation of the RAB for inflation in the AER's 2011–2015 final determination.

609 This shaded row reflects the AER's approach to indexation of the RAB for inflation in the AER's 2011–2015 final determination.

610 AER, *Preliminary decision CitiPower – Depreciation (baseline method),* October 2015.

611 AER, *Preliminary decision CitiPower – Depreciation (baseline method),* October 2015, 'PTRM_comparison' worksheet, cells M23:T35.

612 AER, *Preliminary decision CitiPower – Depreciation (baseline method),* October 2015, 'PTRM Inputs' worksheet, cells C23:H35.

- the inflation value used in the control mechanism for a particular year should be entered in the same year in the RFM (in row 177 of the 'Input' worksheet). As a consequence of the coding in the RFM, for a particular year, the same inflation value used in the control mechanism is used to inflate the RAB; and
- those inflation values are also used to calculate the inflation escalators in the RFM (in row 178 of the 'Input' worksheet), which are used to convert net capital expenditure and depreciation between real 2010 dollars and nominal dollars. The internally inconsistent treatment of actual inflation inputs in the AER's current RFM (i.e. the misalignment between inflation rates in row 177 and inflation escalators in row 178 of the 'Input' worksheet respectively) can be fixed by amending the formula in row 178 such that the inflation escalator for year t is equal to the inflation escalator for year t-1 multiplied by one plus the inflation for year t (instead of for year t-1).

When our proposed modification is implemented, the consistent treatment of actual inflation inputs automatically eliminates the mismatch encountered by the AER in its depreciation model, hence obviating the need to implement an ad hoc adjustment within that model.

We contend that, as the AER's published RFM embodies a manifest error, the AER has power to, and acting correctly and reasonably must, correct this error in making its final determination.

Indexation of the opening RAB at 1 January 2011

We agree with the AER's decision, consistent with our regulatory proposal, to accept that a proposed six-month inflation correction is necessary to rectify the fundamental error made by the AER in approaching the indexation of the 2011 RAB for inflation.

Forecast inflation rate input to PTRM

In summary, in response to the AER's preliminary determination:

- we agree with the AER's decision to accept our approach to determining the forecast inflation rate input to the PTRM;
- we accept the AER's updated estimate of the forecast inflation rate to reflect the most recent RBA forecasts at the time of publishing its preliminary determination; and
- we expect that the estimate in the preliminary determination, accepted for the purpose of this revised regulatory proposal, will be further updated to reflect the RBA's Statement of Monetary Policy to be published in February 2016.

9.4.4 Our revised regulatory proposal

Our revised proposal in respect of inflation, as it relates to both rolling forward the RAB to 1 January 2016 and rolling forward the RAB over the 2016–2020 regulatory control period, are reflected in tables 9.3, 9.4 and 9.8 of this chapter.

Rate of return, gamma and expected inflation 10

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10 Rate of return, gamma and expected inflation

This chapter responds to the Australian Energy Regulator's (**AER's**) preliminary determination on the allowed rate of return, gamma and expected inflation for the 2016–2020 regulatory control period.

For the reasons discussed in this chapter, we do not agree with the AER's approach to estimating the allowed rate of return, the value of imputation credits and forecast inflation. Notwithstanding that we do not agree with the AER's approach to forecasting inflation, for the purpose of this revised regulatory proposal we do not press this matter, rending our revised regulatory proposal conservative in the sense that it is likely to lead to under-estimation of efficient costs.

Our revised regulatory proposal in respect of the overall rate of return, return on equity and return on debt for the first regulatory year of the 2016–2020 regulatory control period (based on the last 20 business days in September 2015), and gamma and inflation for the 2016–2020 regulatory control period, is summarised in tables 10.1 to 10.4 below. Our position on the correct approach to estimating each parameter is set out in sections 10.4 to 10.9 below.

In light of the temporal constraints for the preparation of our response to the AER's preliminary determination, the fact that our accepted equity averaging period and 2016 debt averaging period have not yet occurred, and the uncertainty as to the timing of the Australian Competition Tribunal (**Tribunal**) decision in respect of the applications for merits review of the AER's distribution determinations for the NSW electricity distributors (Ausgrid, Endeavour Energy, Essential Energy), the ACT electricity distributor (**ActewAGL**) and the NSW gas distributor (Jemena Gas Networks (NSW) Ltd (**JGN**)) (**NSW and ACT merits reviews**) (which decision will impact on many of the issues dealt with in this chapter), we have used as a placeholder in the models submitted with this revised regulatory proposal the allowed rate of return estimates used for the purposes of the AER's preliminary determination. While we have used these estimates for convenience, we propose that, for the purpose of making the new distribution determination in substitution for the preliminary determination, the allowed rate of return for 2016 be estimated in accordance with the methodology outlined in this revised regulatory proposal by reference to our accepted equity averaging period and 2016 debt averaging period. We propose that the allowed rate of return then be updated annually for the second and each subsequent regulatory year of the 2016–2020 regulatory control period determined in accordance with the annual debt update process outlined in the AER's preliminary determination.

To assist the AER in making the new distribution determination in substitution for its preliminary determination, after the Tribunal decision in the NSW and ACT merits reviews is published and our annual equity and 2016 debt averaging periods have passed, we intend to submit to the AER a model that sets out the rate of return estimates determined by reference to our proposal and our actual averaging periods.

Table 10.1 Overall rate of return, gamma and inflation

Input	Value	Method
Overall return on equity (post tax)	9.89%	Foundation model approach; as summarised in table 10.2 below; indicative value based on the 20 business days ending 30 September 2015
Overall return on debt (pre tax)	7.76%	As summarised in table 10.3 below; value for 2016 (based on the 20 business days ending 30 September 2015)
Gearing ratio	60:40 debt to equity	
Rate of return (nominal vanilla)	8.61%	(9.89% x 40%) + (7.76% x 60%)

Gamma	0.25	Market value (not utilisation or before-personal-tax and before-personal-costs value) of imputation credits; as summarised in table 10.4 below
Inflation	2.50%	AER's method

Source: CitiPower

Table 10.2 Return on equity

Parameter	Value	Method
Equity beta	0.91	Adjusted for low beta bias and book-to-market bias
Risk free rate	2.75%	Based on the 20 business days ending 30 September 2015
Market risk premium	7.88%	Weighted average of historical, Wright, DGM and independent expert MRP estimates
Overall return on equity	9.89%	2.75% + (0.91 x 7.88%)

Source: CitiPower

Table 10.3 Return on debt

Issue	Revised proposal
Debt transition	No transition
Credit rating	BBB to BBB+
Benchmark term	10 years
Data sources	Simple average of RBA and BVAL for years up to and including 2015; weighted average of RBA, BVAL and Reuters for years 2016 and beyond
Extrapolation method and other adjustments	AER's method as per its preliminary determination
Averaging periods	For year 1, as set out in confidential appendix K to Attachment 3 to the AER's preliminary determination For years 2 to 5, we do not press the future nomination of averaging periods For years preceding the 2016–2020 regulatory control period used in estimating the trailing average, full calendar year averaging periods
Annual updating process	Annual updating process as per AER’s preliminary determination

Source: CitiPower

Table 10.4 Gamma

Parameter	Value	Method
Distribution rate	0.7	Distribution rate for all equity
Theta	0.35	SFG (2013) study
Gamma	0.25	0.7 x 0.35

Source: CitiPower

10.1 Overview

This chapter of our revised regulatory proposal addresses the allowed rate of return, the value of imputation credits (gamma) and the method for forecasting inflation. These topics are addressed together in this chapter because they each impact on the overall return to investors. Specifically:

- under the National Electricity Rules (**Rules**), the allowed rate of return is the post-tax return allowed to investors, calculated as a weighted average of the return on equity and return on debt;[613]
- gamma represents the value of imputation credits to investors associated with the payment of company tax. This value effectively forms part of the overall return to equity investors; and
- forecast inflation is used to adjust the cash flows to maintain a real rate of return framework.[614] It thus has an important interrelationship with the rate of return, and impacts on the overall return to investors. If inflation is not correctly forecasted, the adjustment to cashflows may be too large (or too small) and thus investors may receive an overall return that is too low (or too high).

In order to promote the national electricity objective (**NEO**) set out in section 7 of the National Electricity Law (**Law**), the overall return to investors must be sufficient to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers. Critical to the promotion of efficient investment is that businesses be provided with a reasonable opportunity to recover efficient costs (i.e. the costs that would be incurred by an efficient business in a workably competitive market). This means that:

- the return on debt allowance must be such as to provide a reasonable opportunity to recover at least the efficient debt financing costs of a benchmark efficient entity (**BEE**) with a similar degree of risk as that which applies to us in respect of the provision of standard control services;
- the return on equity allowance must reflect returns required by equity investors to invest in businesses facing a similar degree of risk;
- gamma must reflect the value that equity-holders place on imputation credits (not simply their face value or utilisation rate). If the value of imputation credits is over-estimated, the overall return to equity-holders will be less than what is required to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers; and
- the inflation forecast must reflect market expectations of inflation over the regulatory control period.

The AER's preliminary determination does not provide for an overall return that is consistent with the NEO. For reasons set out in this chapter:

- the allowed rate of return is not commensurate with the efficient financing costs of a BEE with a similar degree of risk as that which applies to us in respect of the provision of standard control services;
- the value of imputation credits is over-estimated, meaning that the reduction to the overall return to account for imputation credits is too large; and

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613 NER, clause 6.5.2(d).

614 While the PTRM is a nominal model in that it has nominal inputs including for the rate of return, the PTRM is properly understood as embodying a real rate of return framework in that it derives a real revenue path for the regulatory period, expressed in terms of the real X factor for each regulatory year of the regulatory period, that includes compensation for a real rate of return (effectively derived by the PTRM by taking a nominal input for the cost of debt and equity and deducting forecast inflation).

- the AER's forecast of inflation is also over-estimated, meaning that the reduction to the overall return to account for expected indexation of the regulatory asset base (**RAB**) is too large and otherwise does not reflect current market expectations.

Our revised regulatory proposal explains our specific concerns with the preliminary decision in relation to the rate of return, value of imputation credits and forecast inflation.

As explained below, in some areas (such as the benchmark gearing level and term of debt) we agree with the AER's position in the preliminary decision. To the extent that the AER proposes to change its position in any of these areas in its final decision, we would need to be informed of that, and provided with a reasonable opportunity to respond to any proposed change of approach.

10.1.1 Achieving the allowed rate of return objective

The allowed rate of return objective (**ARORO**) is the touchstone for estimating the allowed rate of return. The Rules require that:

- the return on equity for a regulatory control period be estimated such that it contributes to the achievement of the ARORO;[615] and
- the return on debt for a regulatory year be estimated such that it contributes to the achievement of the ARORO.[616]

The ARORO is that the rate of return for a distributor is to be commensurate with the efficient financing costs of a BEE with a similar degree of risk as that which applies to the distributor in respect of the provision of standard control services.[617]

As can be seen, the ARORO has two key elements:

- first, the ARORO requires identification of the level of risk that applies to the distributor in respect of the provision of standard control services; and
- secondly, the ARORO requires estimation of efficient financing costs for a BEE facing a similar degree of risk.

We consider that the relevant level of risk is that faced by entities operating in a workably competitive market providing services similar to electricity distribution services within Australia. Therefore, in constructing comparator datasets for the purposes of estimating a rate of return that is commensurate with efficient financing costs of a BEE, these datasets should include entities that face a similar degree of risk to that faced in the provision of electricity distribution services. That is, they should not be restricted to regulated entities.

If we are incorrect that the relevant level of risk is that faced by entities operating in a workably competitive market providing services similar to electricity distribution services within Australia, but rather, the relevant level of risk is that of a regulated energy network business, we submit that the reference to 'efficient financing costs' in the ARORO is to costs incurred (and therefore financing practices adopted) in a workably competitive market to finance an investment with that risk profile.

That is, regardless of what the relevant degree of risk is, once this risk benchmark is established, the assessment of efficient financing costs requires consideration of what financing practices would be engaged in by businesses operating in a workably competitive market, facing the relevant degree of risk. Such an interpretation of the term

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615 NER, clause 6.5.2(f).

616 NER, clause 6.5.2(h).

617 NER, clause 6.5.2(c).

'efficient financing costs' in the ARORO is consistent with the object of regulation itself, which is to simulate competitive market outcomes. This is because it is ultimately competition that drives efficient behaviour and is the benchmark that the Law seeks to replicate. The 'workably competitive market' concept is described in more detail below.

Many of the issues dealt with in this chapter are the subject of the NSW and ACT merits reviews. These issues include the approach taken by the AER to estimating the return on equity and the methodology to estimate the return on debt. The applications were heard in September and October 2015. Once the decision of the Tribunal has been published, we will review the decision and consider the implications, if any, of that decision for the determination the AER is required to make for us. To the extent we consider that the decision does have implications for its determination, we will make any submissions to the AER on those implications as soon as practicable after the Tribunal's decision has been published and considered by us.

10.1.2 Return on debt

As became clear from the detailed consideration of the return on debt issue in the NSW and ACT merits reviews, the method that the AER proposes to adopt in the AER's preliminary determination for estimating the return on debt will not deliver a return on debt estimate which contributes to the achievement of the ARORO and the NEO. The ARORO is concerned with the financing costs and practices that are efficient in the economic sense, that is, the financing costs incurred, and practices adopted, in a workably competitive market.

As set out below, we submit that the debt management practice that would be expected absent regulation is the holding of a staggered portfolio of fixed rate debt, the cost of which can be estimated by the trailing average approach. Given the intent of regulation is to replicate, insofar as possible, the outcomes that would be expected in workably competitive markets, the efficient financing costs to be estimated pursuant to clause 6.5.2 of the Rules are required to be estimated using the trailing average approach and this approach should be adopted without any transition (AER Option 4).

The AER's approach to transitioning to the trailing average estimation method will lead to a return on debt allowance for the 2016–2020 regulatory control period that is below the efficient financing costs of a BEE for that period. This is because:

- the AER's approach proceeds on the incorrect premise that the efficient financing costs of a BEE are those that would be incurred under the financing practices that would have emerged under the previous regulatory approach to estimating the return on debt. The correct approach is to identify the efficient financing costs of a BEE, which are the costs that would be incurred in a workably competitive market (or, put another way, the costs that would be incurred absent regulation);
- the AER considered that the trailing average approach may be more reflective of the actual debt management approaches of non-regulated businesses and therefore, more likely to represent efficient financing practice.[618] The AER found that the efficient financing practice under the trailing average approach is to hold a staggered portfolio of fixed rate debt.[619] The efficient financing costs of a BEE are thus the costs associated with a staggered portfolio of fixed rate debt;
- expert advice from Competition Economists Group (**CEG**) confirms that a 10 year trailing average approach would largely mimic the debt management strategy employed by unregulated infrastructure businesses;[620] and

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618 AER, *Better Regulation, Explanatory Statement, Rate of Return Guideline*, December 2013, pp. 108-111.

619 AER, *Better Regulation, Explanatory Statement, Rate of Return Guideline*, December 2013, pp. 108-110.

620 CEG, *Efficiency of Staggered Debt Issuance*, February 2013 at [92], [97], [101] and [102].

- given that the costs associated with a staggered portfolio of fixed rate debt are best approximated by a trailing average methodology, the immediate implementation of the trailing average approach to estimating the return on debt will provide an allowance that reflects efficient financing costs. Conversely, application of a transition that results in the return on debt being different from efficient financing costs will, by definition, lead to an allowance that is not commensurate with the efficient debt financing costs of a BEE.

For these reasons, we consider that the trailing average approach should be implemented immediately, with no transition.

Alternatively, even if the AER's approach of estimating efficient financing costs by reference to the financing practices that would emerge under regulation were correct, the appropriate approach would be to adopt a hybrid form of transition where only the hedged portion of the base rate component of the return on debt is subject to a transition (optimal hedge form of hybrid transition). This is because the AER has concluded that under the previous on-the-day approach to estimating the return on debt, an efficient financing practice would have been to engage in hedging of the base rate. By contrast, the AER has conceded that the debt risk premium (**DRP**) component of the return on debt cannot be (and could not have been) hedged, with the result that there is no reason for a transition to be applied to it.

If an optimal hedge form of hybrid transition is to be adopted, it would then be necessary to consider to what degree hedging would have been efficient. While the AER's reasoning assumes that the efficient level of hedging was 100 per cent, this is incorrect as a matter of fact and the evidence demonstrates that the efficient level of hedging of the base rate under an on the day approach to estimating the return on debt is significantly less than 100 per cent, at around one third.

On any view of what are efficient financing costs, the AER's transition cannot be justified. Even on the AER's view of the correct approach to estimating efficient financing costs, and assuming that the BEE hedged the base rate 100 per cent, application of the AER's transition would lead to a mismatch between efficient financing costs and the regulatory allowance on the DRP component as the DRP could not have been hedged by a BEE.

In respect of implementation issues, we submit that the AER should:

- adopt a benchmark credit rating of BBB to BBB+, as in the AER's preliminary determination;
- continue to adopt a benchmark term of 10 years;
- for the purposes of estimating the prevailing return on debt for each year included in the trailing average prior to 2016 (i.e. 2007 to 2015), use a simple average of the BBB Bloomberg and Reserve Bank of Australia (**RBA**) data series; and
- for the purposes of estimating the prevailing return on debt for the 2016 regulatory year and beyond, use a weighted average of the RBA, BBB Bloomberg Valuation Service (**BVAL**) and Reuters data series.

We note that the AER's proposed method for estimating the return on debt does not make any allowance for a new issue premium. We consider that, in light of the evidence of a positive and significant new issue premium, making no allowance for this premium (as we have made no allowance for it in this revised regulatory proposal) is highly conservative, in the sense that it is likely to lead to under-estimation of the efficient financing costs of a BEE.

10.1.3 Return on equity

The method adopted by the AER in its preliminary determination does not result in a return on equity that is consistent with the ARORO.

The evidence before the AER is that its estimate is too low. In particular:

- the AER's estimate fails a number of its own cross-checks; and

- it is below all available and relevant evidence as to the return on equity required by investors.

This outcome is the result of:

- the AER relying solely on the output of a model that is known to produce biased estimates, without the AER correcting for this bias;
- the AER applying this model in a way that does not reflect market practice and which results in the return on equity simply tracking movements in the risk-free rate; and
- errors in interpretation and use of key evidence, including empirical evidence relating to the estimation of the market risk premium (**MRP**) and equity beta.

We continue to believe that the ARORO is best achieved through an approach that properly has regard to estimates from all relevant return on equity models. In our regulatory proposal, we proposed that each of the Sharpe Lintner Capital Asset Pricing Model (**SL-CAPM**), the Black Capital Asset Pricing Model (**Black CAPM**), the Fama French Three Factor Model (**FFM**) and Dividend Growth Model (**DGM**) be estimated, and that these estimates each be given appropriate weight in deriving a return on equity estimate. We maintain our view that this approach would best achieve the ARORO.

However if the AER proposes to continue relying solely on the SL-CAPM to estimate the return on equity, it becomes even more important that the estimates of the MRP and equity beta are calculated in a manner that has proper regard to relevant material in order to ensure that its estimate of the return on equity is consistent with the ARORO and reflects prevailing market conditions. Of particular importance are the DGM estimates for the MRP and evidence from wider datasets for the equity beta.

This revised regulatory proposal outlines an alternative approach that involves properly adjusting SL-CAPM parameters to deliver a return on equity that contributes to the achievement of the ARORO and reflects prevailing market conditions. This involves:

- determining a robust ‘starting point’ equity beta estimate, based on a sufficiently large sample of comparable businesses;
- making a transparent and empirically based adjustment to the equity beta estimate to account for the known shortcomings of the SL-CAPM, particularly low beta bias and book-to-market bias; and
- deriving the MRP in a way that gives appropriate weight to measures of the prevailing market conditions (i.e. the prevailing MRP).

This alternative approach leads to an estimate of the prevailing return on equity of 9.9 per cent (based on the 20 business days ending 30 September 2015).

10.1.4 Gearing

We maintain our proposed gearing ratio of 60 per cent, accepted by the AER in its preliminary determination, for the reasons set out in our regulatory proposal, and the AER's preliminary determination. We note that this gearing assumption is broadly consistent with evidence of gearing ratios for businesses operating in a workably competitive market providing services similar to standard control services.

10.1.5 Gamma

The AER’s estimate of gamma does not reflect the value of imputation credits to investors. The AER has over-estimated gamma, meaning that the reduction to the overall return to account for imputation credits is too large.

The AER’s approach to estimating gamma is premised on an incorrect interpretation of the Rules. The AER seeks to estimate gamma on a 'pre-personal-costs' basis, which is equivalent to estimating gamma as the rate of utilisation (or assumed utilisation) of imputation credits, rather than their value to investors.

As a result, the AER has erred in its use of evidence in relation to gamma because:

- the AER uses equity ownership rates as direct evidence of the value of distributed credits (**theta**), when in fact equity ownership rates are no more than an upper bound (or maximum) for this value;
- the AER also uses redemption rates as direct evidence of the value of theta, when in fact redemption rates are no more than an upper bound (or maximum) for this value; and
- the AER has erred in concluding that market value studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the task of measuring theta. Market value studies are direct evidence of the value of imputation credits to investors.

Further, the AER has made errors in its interpretation and use of key evidence, including by proceeding on the incorrect footing that estimates of theta based on data for listed companies can only be combined with estimates of the 'listed equity' distribution rate.

On a proper interpretation of the empirical evidence:

- both tax statistics and equity ownership data indicate that theta can be no higher than 0.45, and that therefore the upper bound for gamma is 0.3; and
- the best evidence as to the value of imputation credits – from SFG's updated dividend drop-off study – indicates that theta is approximately 0.35 and that gamma is 0.25.

Even on the AER's interpretation of the Rules, its gamma estimate cannot be supported. The evidence demonstrates that if gamma is estimated on a 'pre personal costs' basis, the best estimate is approximately 0.3.

10.1.6 Forecast inflation

Recent market evidence demonstrates that the AER's forecasting method is currently over-estimating inflation.

The consequence of this is that:

- the inflation forecast used to make adjustments to cash flows is inconsistent with the forecast of inflation implied in the nominal rate of return; and
- the downward adjustment to the negative 'indexation of the regulatory asset base' building block will be too large, thus artificially depressing the overall return to investors.

We consider that an alternative forecasting method, based on market data, is to be preferred to the AER's method, as it would ensure consistency between the inflation forecast used to make adjustments to cash flows and the forecast of inflation implied in the nominal rate of return. Nonetheless, for the purpose of this revised regulatory proposal only, we do not press this matter and apply a forecast of inflation for the 2016–2020 regulatory control period dervied using the AER's forecasting method. This renders our revised regulatory proposal highly conservative, in the sense that it is likely to lead to under-estimation of efficient costs.

10.1.7 Interrelationships

There is a well-recognised interrelationship between the return on equity and the value of imputation credits – since the MRP needs to be grossed up for the value of imputation credits, a higher theta estimate implies a higher required return on equity.

- This interrelationship is accounted for in this revised regulatory proposal and the supporting expert evidence.

- If the AER were to reduce its estimate of theta to 0.35, while maintaining its current approach to estimating the MRP, no adjustment to the AER's MRP estimate would be necessary. This is because the top of the AER's range of estimates of the historical average MRP (used by the AER as its MRP point estimate) would remain at 6.5 per cent.[621]

There is also an interrelationship between the method for forecasting inflation and the amount that is deducted from the annual revenue requirement for indexation of the RAB, and between the allowed rate of return and the method for forecasting inflation. Due to these interrelationships, the forecast of inflation needs to be accurate (i.e. as close as possible to actual inflation, which is used to roll forward the RAB at the end of the regulatory period) and consistent with the implied forecast of inflation in the nominal rate of return. The best way to do this is to rely on the same dataset (i.e. market prices of securities) to estimate both. Nonetheless, as noted above, we have applied a forecast of inflation derived using the AER's forecasting method for the purpose of this revised regulatory proposal only.

We do not accept that there is an interrelationship between the method for transitioning to the trailing average approach to estimating the return on debt and the equity beta. As noted by Chairmont, the required return on equity is not affected by the DRP mismatch risk as it is a diversifiable specific risk rather than a component of market systematic risk.[622] Therefore any change in the AER's approach to estimation of the return on debt (including any change to the transition method) will not affect the equity beta.

Finally, we consider that the return on equity and return on debt need to be estimated on the basis of a consistent approach to the ARORO. As explained below, our proposed approaches to estimating the return on equity, return on debt and the overall rate of return, as set out in this chapter, are consistent with the approach to the ARORO described in section 10.1.1 above.

10.2 Rule requirements

10.2.1 Allowed rate of return

Clauses 6.12.1(5) and (5A) of the Rules provides that the constituent decisions on which a distribution determination is predicated include (amongst others):

- a decision on the allowed rate of return for each regulatory year of the regulatory control period in accordance with clause 6.5.2 of the Rules; and
- a decision on whether the return on debt is to be estimated using a methodology which results in the return on debt being different or potentially different for different regulatory years in the regulatory control period and, if so, on the formula to effect the resulting change to the annual revenue requirement.

The allowed rate of return for a regulatory year is applied to the value of the RAB at the beginning of that regulatory year to determine the return on capital building block for that regulatory year (clauses 6.4.3(a)(2) and (b)(2), and 6.5.2(a) of the Rules).

Clause 6.5.2(b) of the Rules provides that the allowed rate of return is to be determined such that it achieves the ARORO.

621 For reasons set out under the heading 'The AER's application of the SL-CAPM' in section 10.4.3, we do not agree with the AER's approach to estimating the MRP. However we note that if the AER were to maintain the same approach to estimating the MRP while lowering its estimate of theta, its estimate of the MRP would not need to change.

622 Chairmont, *Financing Practices Under Regulation: Past and Transitional*, 13 October 2015, p. 40.

The ARORO is set out in clause 6.5.2(c) of the Rules and is that the rate of return for a distributor is to be commensurate with the efficient financing costs of a BEE with a similar degree of risk as that which applies to the distributor in respect of the provision of standard control services.

Clause 6.5.2(e) of the Rules provides that, in determining the allowed rate of return, regard must be had to:

- relevant estimation methods, financial models, market data and other evidence;
- the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and
- any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.

Return on equity

Clause 6.5.2(f) of the Rules provides that the return on equity for a regulatory control period must be estimated such that it contributes to the achievement of the ARORO, and clause 6.5.2(g) of the Rules provides that, in estimating the return on equity, regard must be had to the prevailing conditions in the market for equity funds.

Return on debt

Clause 6.5.2(h) of the Rules states that the return on debt for a regulatory year must be estimated such that it contributes to the ARORO, and clause 6.5.2(k) of the Rules provides that, in estimating the return on debt, regard must be had to the following factors:

- the desirability of minimising any difference between the return on debt and the return on debt of a BEE referred to in the ARORO;
- the interrelationships between the return on equity and the return on debt;
- the incentives that the return on debt may provide in relation to capital expenditure over the regulatory control period, including as to the timing of any capital expenditure; and
- any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a BEE referred to in the ARORO that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory control period to the next.

Clause 6.5.2(i) of the Rules provides that the return on debt may be estimated using a methodology which results in the return on debt either being the same for each regulatory year in the regulatory control period or being different, or potentially being different, for different regulatory years in the regulatory control period. Clause 6.5.2(l) of the Rules states that if the return on debt is to be estimated using a methodology which results in the return on debt being different, or potentially being different, in different regulatory years, then a resulting change to the distributor's annual revenue requirement must be effected through the automatic application of a formula that is specified in the distribution determination.

10.2.2 Gamma

Clause 6.12.1(5B) of the Rules provides that the constituent decisions on which a distribution determination is predicated include (amongst others) a decision on the value of imputation credits as referred to in clause 6.5.3 of the Rules.

The value of imputation credits (referred to as Greek letter, *γ*, or 'gamma') is an input into the corporate income tax calculation, the formula for which is set out in clause 6.5.3 of the Rules (clauses 6.4.3(a)(4) and (b)(4), and 6.5.3 of the Rules). However, the value adopted for gamma ultimately plays a role in determining returns for equity-holders. For example, if the value ascribed to imputation credits is greater than the actual value of the imputation credits distributed to equity-holders, the overall return to equity-holders will be less than what is required to promote efficient investment in, and the efficient operation and use of, electricity services in the long term interest of consumers. We therefore address gamma in this chapter.

The relevant Rules relating to gamma are:

- clause 6.5.2(d)(2) of the Rules, which requires that the allowed rate of return for a regulatory year must be 'determined on a nominal vanilla basis that is consistent with the estimate of the value of imputation credits'; and
- clause 6.5.3 of the Rules, which defines 'γ' as 'the value of imputation credits'.

10.2.3 Inflation

Clause 6.12.1(10) of the Rules provides that the constituent decisions on which a distribution determination is predicated include (amongst others) a decision on appropriate amounts, values or inputs to be used in determining the annual revenue requirement for each regulatory year. One of these is necessarily a forecast of inflation in each regulatory year. Clause 6.3.2(a)(2) of the Rules further provides that a building block determination is to specify appropriate methods for indexation of the RAB.

The forecast of inflation for a regulatory control period is an input to the determination of all of the building blocks of the annual revenue requirement for each regulatory year. This includes, most obviously, the indexation of the RAB building block, being a negative adjustment equal to the amount by which the RAB must be increased for inflation in rolling forward that RAB to the second or a subsequent regulatory year to maintain the real value of that RAB (clause 6.4.3(a)(1) and (b)(1), and S6.2.3(c)(4) of the Rules).

10.3 Background

10.3.1 Recent changes to the rate of return rules

The rules relating to the allowed rate of return and gamma were amended in November 2012 (**2012 Rule Amendment**). A key aspect of the 2012 Rule Amendment was the removal of the requirement to estimate the return on equity using the SL-CAPM. This was replaced with a requirement to estimate the return on equity such that it contributes to the achievement of the ARORO, having regard to relevant estimation methods, financial models, market data and other evidence.

In making the 2012 Rule Amendment, the Australian Energy Market Commission (**AEMC**) stated that the Amendments provided the regulator with the flexibility to adopt the approach it considers appropriate to estimate the rate of return, 'provided it considers relevant estimation methods, financial models, market data and other information'. The AEMC noted that:[623]

> *This is so the best estimate of the rate of return can be obtained that reflects efficient financing costs of the service provider at the time of the regulatory determination.*
>
> *In this way, the regulator can better respond to changing financial market conditions, particularly where volatile market conditions impact on a service provider's ability to attract sufficient capital to finance the expenditure necessary to provide a reliable energy supply to consumers.*

[623] AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p. iii.

In relation to the return on equity, one of the key drivers of the Rule changes was a concern that estimation of the return on equity had become overly formulaic, and unduly bound to a single model (the SL-CAPM). Such a concern was expressed by the Expert Panel on Limited Merits Review:[624]

> *Put bluntly, at the moment the AER is required to proceed, as a matter of law, on the basis of a model that is known to abstract from a factor considered (in the Panel's view, rightly) to be a matter of such significance (i.e. regulatory risk or uncertainty) that it is afforded special mention in the revenue and pricing principles section of the NEL.*
>
> *That this is more than a theoretical point is indicated by the fact that the Financial Investors Group told us that they had been concerned about the narrow, CAPM focus of the regulatory approach to date, and had urged the AER to pay more attention to conditions in capital markets themselves (in contrast to models of those markets). Whilst the Panel believes that the AER has rather more discretion than the AER itself appears to believe it has, it does appear to be the case that there is an inconsistency in the current combination of laws and rules that is impeding a more realistic, market-focused approach to the determination of returns on capital.*
>
> *The practical relevance of the problem has also been illustrated by the ACT's recent ATCO decision, the detail of which the Panel has not yet had time to fully absorb. In the name of regulatory certainty, the decision appears to elevate the standing of the CAPM in the NGR to something akin to its standing in the NER. The Panel is concerned that binding regulatory decisions hand and foot to a financial model **with known defects** does not immediately commend itself as an approach that will advance the NEO and NGO.*

The AEMC echoed this concern in its rule determinations in relation to the 2012 Rule Amendments, and accordingly sought to devise a new framework for estimating the rate of return that would require consideration of a wider range of models and estimation techniques. In its draft rule determination, the AEMC stated:[625]

> *The rate of return estimation should not be formulaic and be driven by a single financial model or estimation method. The estimation approach to equity and debt components should include consideration of available estimation methods, financial models, market data and other evidence to produce a robust estimate that meets the overall rate of return objective. This means giving the regulator discretion on how it should estimate these components, rather than limiting the estimation process to a particular financial model or a particular data source. **In the context of estimating the return on equity, the estimation should not be limited to the standard CAPM, but should consider other relevant evidence**. [Emphasis added]*

The AEMC, like the Expert Panel on Limited Merits Review, clearly considered that an estimation approach that was limited to a single model would not best meet the NEO and the revenue and pricing principles. Rather the AEMC considered that estimates are likely to be more robust and reliable if they are based on a range of estimation methods. The AEMC explained:[626]

> *There are a number of other financial models that have varying degrees of weaknesses. Some of the financial models that have gained some prominence include the Fama-French three-factor model, the Black CAPM, and the dividend growth model. Weaknesses in a model do not necessarily invalidate the usefulness of the model.*

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624 Professor George Yarrow, The Hon Michael Egan, Dr John Tamblyn, *Review of the Limited Merits Review Regime: Stage One Report*, 29 June 2012, pp. 41 - 42.

625 AEMC, *Draft Rule Determinations: Draft National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; Draft National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 23 August 2012, p. 47.

626 AEMC, *Draft Rule Determinations: Draft National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; Draft National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 23 August 2012, p. 48.

> ***Ultimately, it is important to keep in mind that all these financial models are based on certain theoretical assumptions and no one model can be said to provide the right answer****. [Emphasis added]*
>
> *Given that there are other financial models and methods for estimating the cost of equity capital that vary in their acceptance academically and consequent usage by market practitioners, restricting consideration to the CAPM alone would preclude consideration of other relevant estimation methods.*
>
> ***The Commission is of the view that estimates are more robust and reliable if they are based on a range of estimation methods, financial models, market data and other evidence****. A framework that eliminates any relevant evidence from consideration is unlikely to produce robust and reliable estimates, and consequently is unlikely to best meet the NEO, the NGO and the RPP. [Emphasis added]*

The changes to the return on debt rules were at least partly driven by a concern that the 'on-the-day' approach to estimating the return on debt previously required by the Rules did not reflect efficient financing practices engaged in by businesses operating in competitive markets. The AEMC considered that the NEO would be advanced by an approach that better aligned with efficient financing and risk management practices that might be expected in the absence of regulation.

In the final determination in relation to the 2012 Rule Amendment, the AEMC indicates that one of its fundamental policy objectives in amending the allowed rate of return framework was to provide flexibility to take account of changing market conditions by making necessary adjustments to the method for estimating the return on debt.[627]

The AEMC emphasised the intention of the amended rule to align the return on debt estimate with the return required by investors of debt capital issued by a benchmark efficient service provider:[628]

> *The return on debt estimate represents the return that investors of debt capital would require from a benchmark efficient service provider. Aligning the return on debt estimate with the efficient expected cost of debt of a service provider is therefore an important element in determining the rate of return.*

The 2012 Rule Amendment amended clause 6.5.2 of the Rules to explicitly permit the return on debt methodology to be designed to reflect an average return that would have been required by debt investors in a BEE if it raised debt over an historical period. The AEMC considered that the amendment would permit the adoption of the trailing average approach to estimate the return on debt, which would better align efficient debt costs with the regulatory allowance.[629]

> *The Commission's rate of return framework draft rule proposal provides the flexibility for the regulator to consider alternative approaches to estimating the return on debt, including historical trailing average approaches that may better align the debt servicing costs of an efficiently run service provider with the regulatory estimate of the return on debt.*

While the amended Rules did not specify the methodology to be used to estimate the return on debt, the AEMC was clear in the guidance set out in its final rule determination that whatever methodology was used, it should

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627 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, pp. 44, 45 - 46, 49 and 55 - 56.

628 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p. 73.

629 AEMC, *Draft Rule Determinations, Draft National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; Draft National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 23 August 2012, p. 78.

result in a regulatory allowance for the return on debt that reflects financing practices (and ultimately costs) that, insofar as possible, would be expected absent regulation.[630]

> *In its draft rule determination, the Commission considered that the long-term interests of consumers would be best served by ensuring that the methodology used to estimate the return on debt reflects, to the extent possible, the efficient financing and risk management practices that might be expected in the absence of regulation.*

The AEMC went on to consider whether it should depart from this approach in the draft determination, and concluded that (relevantly) there should be no change. Further, the AEMC observed that the NEO and the revenue and pricing principles are more likely to be met by a methodology that allows the AER to more accurately match debt conditions in the market for funds.[631]

10.3.2 The ARORO

Under the Rules, as amended by the AEMC, the ARORO is the touchstone for estimating both the return on equity and the return on debt. The Rules require that:

- the return on equity for a regulatory control period be estimated such that it contributes to the achievement of the ARORO;[632] and
- the return on debt for a regulatory year be estimated such that it contributes to the achievement of the ARORO.[633]

The ARORO is that the rate of return for a distributor is to be commensurate with the efficient financing costs of a BEE with a similar degree of risk as that which applies to the distributor in respect of the provision of standard control services.[634]

As can be seen, the ARORO has two key elements:

- first, the ARORO requires identification of the level of risk that applies to the distributor in respect of the provision of standard control services; and
- secondly, the ARORO requires estimation of efficient financing costs for a BEE facing a similar degree of risk as that distributor.

We consider that the relevant level of risk is that faced by entities operating in a workably competitive market providing services similar to electricity distribution services within Australia. Therefore, in constructing comparator datasets for the purposes of estimating a rate of return that is commensurate with efficient financing costs of a BEE, these datasets should include entities that face a similar degree of risk to that faced in the provision of electricity distribution services. That is, they should not be restricted to regulated entities. For example, as will be discussed below:

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630 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p. 76.

631 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p. 86.

632 NER, clause 6.5.2(f).

633 NER, clause 6.5.2(h).

634 NER, clause 6.5.2(c).

- in estimating the equity beta for a BEE facing a similar degree of risk as that which applies to the distributor in respect of the provision of standard control services, businesses in other sectors and other countries facing a similar degree of risk should be included in the dataset; and
- in estimating the return on debt, yields are measured using benchmark indices for the relevant credit rating band, with those indices reflecting bond yields across a wide range of businesses within that credit rating band (i.e. a range of different businesses facing a similar degree of risk, including businesses operating in competitive markets).

If we are incorrect that the relevant level of risk is that faced by entities operating in a workably competitive market providing services similar to electricity distribution services within Australia, but rather, the relevant level of risk is that of a regulated energy network business subject to economic regulation under the Law, we submit that the reference to 'efficient financing costs' in the ARORO is to costs incurred (and therefore financing practices adopted) in a workably competitive market to finance an investment with that risk profile.

Moreover, even if the relevant level of risk is that of a regulated energy network business subject to economic regulation under the Rules, in many cases it will be necessary to look beyond just those businesses that supply regulated energy network services within Australia in order to produce sufficiently large datasets for the estimation of risk parameters. Specifically in the context of equity beta, given that the sample of Australian energy network businesses is too small, the dataset for estimating risk parameters needs to be enlarged by adding other businesses facing a *similar* degree of risk.

Once the relevant degree of risk is established, the task is then to estimate the efficient financing costs of a BEE facing a similar degree of risk. As noted above, regardless of what the relevant degree of risk is, once this risk benchmark is established, the assessment of efficient financing costs requires consideration of what financing practices would be engaged in by businesses operating in a workably competitive market, facing the relevant degree of risk. Such an interpretation of the term 'efficient financing costs' in the ARORO is consistent with the object of regulation itself—which is to simulate competitive market outcomes. This is because it is ultimately competition that drives efficient behaviour.

The rationale of economic regulation of network assets is to, insofar as possible, mimic the operation of, and replicate the outcomes in, a workably competitive market. This is because, by reason of the adjustments to quantity and pricing that occur in response to changes in these markets, it is in such markets that economic efficiency is achieved. For example, the Expert Panel on Energy Access Pricing has noted:[635]

> *The central objective of price control is to constrain the exercise of market power by firms that do not face effective competition for their services. Regulation and, specifically, the periodic determination of maximum prices or revenue is directed at achieving outcomes that could otherwise be expected from effective competition.*

The Expert Panel noted that regulatory regimes typically set prices by reference to costs because costs associated with supply are a central element of pricing outcomes in competitive markets.[636]

> *Virtually all regulatory regimes set controlled prices by reference to an assessment of costs. The reason is that the cost of supply – in conjunction with the role of consumer preferences in determining the appropriate service and product mix – is a primary driver of price outcomes in effectively competitive markets.*

The AEMC has commented on the objective of regulation in similar terms to the Expert Panel.[637]

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[635] Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p. 118.

[636] Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p. 98.

The role of incentives in regulation can be traced to the fundamental objective of regulation. That is, to reproduce, to the extent possible, the production and pricing outcomes that would occur in a workably competitive market in circumstances where the development of a competitive market is not economically feasible.

The AEMC has also noted that regulatory arrangements attempt to mimic competitive markets given that economic efficiency is achieved in those markets. In the context of electricity transmission, which is subject to a similar regulatory framework to electricity distribution, the AEMC stated:[638]

TNSPs, like most businesses, operate in an uncertain environment. Uncontrollable, external events as diverse as changes in economic growth, climate and regulatory obligations can alter the quantity and nature of the services required to be provided by TNSPs. In a normal competitive market, production and pricing behaviour adjusts in response these changes. In these markets, efficient producers are able to recover their costs and should generally earn at least a normal return on their investments. As highlighted above, the regulatory arrangements need to mimic the operation of a competitive market as closely as possible.

The term 'workably competitive market' refers to a market in which no firm has a substantial degree of market power and in which market forces increase efficiency beyond that which could be achieved in a non-competitive market, even if perfect competition is not attained. These concepts were explored by the Western Australian Supreme Court in the context of section 8.1 of the Gas Code that set out general principles applying to reference tariffs, which included that reference tariffs should be designed with a view to achieving the objective of replicating the outcome of a competitive market.[639]

Workable competition is said originally to have been developed over half a century ago by anti-trust economists. In simple terms it indicates a market in which no firm has a substantial degree of market power…I am left with the clear impression that in the field of competition policy, especially market regulation, the prevailing view and usage among economists is that a reference to a competitive market is to a workably competitive market. In the particular context of the promotion of a competitive market for natural gas it would be surprising if what was contemplated was a theoretical concept of perfect competition, as the subject matter involves very real-life commercial situations. Workable competition seems far more obviously to be what is contemplated. This is clearly consistent with the approach of the Hilmer Report…

The Court went on to set out its interpretation of the requirement to replicate the outcome of a competitive market in the context of a regulatory framework applying to monopoly infrastructure.[640]

What is in contemplation in s 8.1(b) is a competitive market in the field of gas transportation. The objective is to replicate what would be the outcome if there was competition for the transportation of gas by the pipeline in question, even though it is the premise of the Act and the Code that the pipeline is in a monopoly situation and it would be uneconomic to construct another. The objective seems to necessitate the application of economic methods and theory, albeit to replicate the outcome of a workably competitive market, because the achievement of competition in fact is not possible.

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637 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2006, p. 96.

638 See, for example: AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2006, p. 54; and AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p. 182.

639 *Re Dr Ken Michael AM; Ex parte Epic Energy (WA) Nominees Pty Ltd* [2002] WASCA 231 at [124].

640 *Re Dr Ken Michael AM; Ex parte Epic Energy (WA) Nominees Pty Ltd* [2002] WASCA 231 at [127].

The Court then discussed the relationship between efficiency and the outcomes of a workably competitive market, noting that the revenues earned from the provision of services in a workably competitive market would approximate efficient costs.[641]

> *Section 8.1(b) provides that a reference tariff should be designed with a view to replicating the outcome of a competitive market, ie as indicated earlier, a workably competitive market. The discussion of the concept of a competitive market earlier in these reasons, especially the close interrelationship recognised by economists between the role of a competitive market and the achievement of economic efficiency, suggests that s 8.1(b) and s 8.1(a) are more complementary than antithetical, although they need not always be in harmony. As far as the expert evidence discloses, a competitive market in the sense of a workably competitive market appears to be viewed by the general body of economic opinion as likely, over time, to lead to economic efficiency or at least to greater economic efficiency. As the Hilmer Report puts it, the promotion of effective competition is generally consistent with maximising economic efficiency. This would suggest that, over time, the revenue earned by a service provider from a reference service, if that service was provided in a workably competitive market, would approximate the efficient costs of delivering the service. That also helps to confirm that the concept of efficient costs, like the outcome of a workably competitive market, is not capable of precise or certain calculation and at best, can only be approximated. Both are based on many assumptions. How best to determine the efficient level of costs or the outcome of a competitive market are matters of economic theory and practice which, on the evidence, are in the course of constant revision, development and refinement.*

In the context of gas regulation by the National Gas Law and National Gas Rules, the objective of which is similar to electricity regulation, the AER has also drawn the connection between the efficiency objective and the recovery of costs that would be incurred in a workably competitive market.[642]

> *The AER submitted that rule 91 requires the AER to permit service providers a reasonable opportunity to recover what the AER considers "legitimate costs". Legitimacy, according to the AER is informed by the NGO [National Gas Objective] and, in particular, means costs that would be incurred in a "workably competitive market". The requirement for replication of a workably competitive market outcome is said to be derived from the intent of the regulatory framework.*

The Tribunal has confirmed that the Law and the Rules 'seek to ensure that an NSP operates and invests efficiently in the manner of a firm in a competitive environment'.[643] It is implicit in the Tribunal's observations that the Tribunal accepted the notion that 'efficient costs' are those that would be incurred by the hypothetical business in a workably competitive market.

The term 'efficient' in the ARORO is to be interpreted consistently with how that term is used elsewhere in the regulatory regime. Most relevantly the term 'efficient' appears in the NEO and the revenue and pricing principles.

The second reading speech made on the introduction of the Bill which contained the Law with the current NEO noted the following with respect to the NEO:[644]

> *The national electricity market objective in the new National Electricity Law is to promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to*

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641 *Re Dr Ken Michael AM; Ex parte Epic Energy (WA) Nominees Pty Ltd* [2002] WASCA 231 at [143]. Section 8.1(a) of the Code referred to the objective of providing the service provider with the opportunity to earn a stream of revenue that recovers the efficient costs of delivering the reference service over the expected life of the assets used in delivering that service.

642 *Application by Envestra Ltd (No 2)* [2012] ACompT 3 at [183].

643 *Application by EnergyAustralia and Others* [2009] ACompT 8 at [106].

644 House of Assembly Hansard, *Second reading speech for the National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005*, 9 February 2005, p. 1452.

price, quality, reliability and security of supply of electricity, and the safety, reliability and security of the national electricity system.

The market objective is an economic concept and should be interpreted as such. For example, investment in and use of electricity services will be efficient when services are supplied in the long run at least cost, resources including infrastructure are used to deliver the greatest possible benefit and there is innovation and investment in response to changes in consumer needs and productive opportunities.

The long term interest of consumers of electricity requires the economic welfare of consumers, over the long term, to be maximised. If the National Electricity Market is efficient in an economic sense the long term economic interests of consumers in respect of price, quality, reliability, safety and security of electricity services will be maximised.

…

It is important to note that all participating jurisdictions remain committed to the goals expressed in the current market objectives set out in the old Code, even though they are not expressly referred to in the new single market objectives. Applying an objective of economic efficiency recognises that, in a general sense, the national electricity market should be competitive…

The AER has previously referred to this text of the second reading speech, noting that the NEO is fundamentally an efficiency objective and that the NEO seeks to emulate effectively competitive market outcomes.[645]

In a competitive market, a firm has a continuous incentive to respond to consumer needs at the lowest cost (that is, operate efficiently) because competition may force it to exit the market if it does not. In addition, the firm has an incentive to improve its efficiency because it will enjoy greater market share if it can provide the best service at the lowest cost to the consumer. Essentially, the NEO imposes the pressures of competition on natural monopolies.

In its report on energy access pricing the Expert Panel also referred to the second reading speech text extracted above and noted that 'the elements of productive, allocative and dynamic efficiency, neatly encapsulated in the first paragraph of the extract, are at the core of the objective'.[646]

The term 'efficient' is also used in other provisions of the Rules, including clauses 6.5.6 and 6.5.7 relating to forecast operating and capital expenditure. The AER has interpreted 'efficient costs' in the context of the expenditure provisions of the Rules as being 'those expected costs based on outcomes in a workably competitive market'.[647]

It is a principle of statutory interpretation that where a word is used consistently in legislation it should be given the same meaning.[648] Further, the Law provides that words and expressions used in the Rules have the same meaning as they have in the Law.[649] Therefore, the term 'efficient' in the ARORO is to be given the same meaning as 'efficient' in the NEO. Further, in construing the term 'efficient costs' where it appears in the Rules, the interpretation that will best achieve the purpose of object of the Law is to be preferred to any other interpretation.[650] As such, the term 'efficient costs' is to be construed consistently with the economic concept of efficiency with which, as set out in detail above, it is well accepted the NEO is concerned.

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645 AER, *Better Regulation, Explanatory Statement, Expenditure Forecast Assessment Guideline*, November 2013, p. 17.

646 Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, April 2006, p. 37.

647 AER, *Better Regulation, Explanatory Statement, Expenditure Forecast Assessment Guideline*, November 2013, p. 47.

648 See discussion in Pearce and Geddes, *Statutory Interpretation in Australia* (LexisNexis Butterworths, 2014), pp. 150 - 151.

649 NEL, Schedule 2, clause 13(1). See also NEL, section 3, and clause 41 of Schedule 2.

650 NEL, Schedule 2, clause 7. See also NEL, section 3 and clause 41 of Schedule 2.

An interpretation of the term 'efficient costs' in the ARORO as being the costs that would be incurred in a workably competitive market is consistent with the intent of the AEMC, as stated in its final position paper accompanying the 2012 Rule Amendment. As noted above in the context of the return on debt, the AEMC made clear that the NEO would be best served by adoption of a return on debt estimation methodology that reflects the efficient financing and risk management practices that might be expected in the absence of regulation.[651]

In this connection it may also be observed that what is relevant to the estimation of the return on debt is the return required by debt investors. This return is largely (or wholly) unaffected by the methodology adopted by the regulator to estimate the return on debt allowance. As such, it should be clear that efficient financing costs are those that would be incurred absent regulation and cannot be defined by reference to how a regulated entity might respond to any particular methodology adopted by the regulator to estimate the return on debt.

It may also be observed from the AEMC material that the intention of the 2012 Rule Amendment is to align the regulatory estimate with the return that investors of debt capital would require from a benchmark efficient service provider.[652] The regulatory methodology does not determine those costs. Rather, it must be responsive to such costs – they have existence independent of the regulatory methodology and the regulatory methodology must be designed to capture them.

Consistent with the statements of the AEMC set out above, the long term interests of consumers are best served by ensuring that the methodology used to estimate the return on debt reflects, to the extent possible, the efficient financing and risk management practices that might be expected in the absence of regulation. Specifically with regard to the determination of the characteristics of the BEE, the AEMC stated that the most appropriate benchmark to use in the regulatory framework for all service providers is *the efficient private sector service provider*.[653]

The AER itself appears to recognise that in estimating the financing costs of a *regulated* business under the Rules, these should be consistent with what would be expected in the context of *unregulated* efficient businesses.[654]

> *The allowed rate of return objective requires us to set a rate of return commensurate with the efficient financing costs of the benchmark efficient entity. We do not consider this to be only a theoretical proposition. Rather, it should be consistent with observable good practice in efficient businesses. We consider that, in practice, businesses make financing and investment decisions using widely accepted economic and financial models of the efficient cost and allocation of capital. To the extent that we use models for estimating the rate of return that are consistent with those widely used in practice, we are more likely to achieve the allowed rate of return objective.*

Identifying efficient financing practices by reference to the incentives created by a particular regulatory approach avoids the very object of the regulatory regime—being to, insofar as possible, create an environment in which the costs incurred (and ultimately allowed to be recovered) are efficient costs. The correct enquiry starts with an identification of what are efficient costs, and then a methodology is designed that, insofar as possible, permits those efficient costs to be recovered.

A paper published by the ACCC and AER's Regulatory Development Branch summarises the point accurately:[655]

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651 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p. 76.

652 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p. 73.

653 AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p. 72.

654 AER, *Better Regulation, Explanatory Statement, Rate of Return Guideline*, December 2013, p. 28.

…when determining a new regulatory cost of debt approach, debt practices which are a product of the regulatory environment should be ignored. This is because these practices will change if the regulatory environment changes. If in setting a new regulatory framework, a regulator considers debt practices that are a result of businesses reacting to the existing regulatory framework, it may create a self fulfilling method that may not necessarily be efficient…

The use of swap contracts to lock in the cost of debt for the access arrangement is a consequence of the regulatory framework, and their use by regulated businesses would change if the regulatory framework were to change. Ideally the regulatory framework for the cost of debt should reflect the efficient debt practices that occur in a competitive market. This would align competitive incentives with regulatory incentives.

In short, the ARORO requires the formulation of methodologies to be used to estimate the rate of return, including the return on debt, that, insofar as possible, provide a return that is commensurate with forward-looking efficient costs, being the costs that would be incurred in a workably competitive market. Any other approach would lead to the absurd and circular result that any cost incurred is efficient where the regulatory approach provides an incentive for it to be incurred, even though it would not be incurred in a workably competitive market. Such an approach is inconsistent with the objective of the regulatory regime.

10.3.3 Matters that the AER must have regard to in estimating the rate of return

Regard must be had to several relevant matters in estimating the rate of return, including:[656]

- relevant estimation methods, financial models, market data and other evidence;
- the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and
- any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.

This requirement reflects the view of the AEMC, referred to above, that no one model or method can be said to provide the 'right' answer, and that estimates are more robust and reliable if they are based on a range of estimation methods, financial models, market data and other evidence.

In estimating the return on equity, regard must also be had to the prevailing conditions in the market for equity funds.[657]

In estimating the return on debt, the Rules also require that regard be had to the following four factors:[658]

- the desirability of minimising any difference between the allowed return on debt and the return on debt of a BEE referred to in the ARORO;
- any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt;
- the incentives that the return on debt may provide in relation to capital expenditure over the regulatory period, including as to the timing of any capital expenditure; and

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655 Regulatory Development Branch, Australian Competition and Consumer Commission (H Smyczynski and I Popovic), *Estimating the Cost of Debt: A Possible Way Forward*, April 2013, p. 11.

656 NER, clause 6.5.2(e).

657 NER, clause 6.5.2(g).

658 NER, clause 6.5.2(k).

- any impacts (including in relation to the costs of servicing debt across regulatory periods) on a BEE referred to in the ARORO that could arise as a result of changing the method that is used to estimate the return on debt from one regulatory control period to the next.

10.3.4 Gamma – the value of imputation credits

In relation to gamma, the Rules now require an estimate of 'the value of imputation credits'.

Importantly, clause 6.5.3 of the Rules was amended in November 2012 to change the definition of gamma from 'the assumed utilisation of imputation credits' to 'the value of imputation credits'. The change to the Rules was entirely appropriate, given that the estimate of gamma determines an amount to deduct from allowed revenue to reflect the value that investors obtain from imputation credits.[659]

It is important that gamma be accurately estimated, since if the value of imputation credits is over-estimated this deduction will be too large and the overall return will be too low.

10.3.5 The importance of an accurate inflation forecast

Forecast inflation impacts on the overall return through its inclusion in the annual revenue requirement building blocks of a negative building block for RAB indexation (which is applied in practice as a deduction to the depreciation building block).[660] This deduction is made in order to maintain a real rate of return framework (i.e. because under the Rules, a nominal rate of return[661] is applied to an inflation-adjusted asset base[662]). In order to ensure an appropriate overall return, the inflation forecast used to make this adjustment to cash flows needs to be as accurate as possible, and consistent with the forecast of inflation implied in the nominal rate of return.

10.3.6 Achieving the NEO

Providing for an overall return that is consistent with the ARORO is necessary to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers, consistent with the NEO.

If the level of return is set too low, we may not be able to attract sufficient funds to make the required investments in the network and reliability and service standards may decline.

10.4 Return on equity

10.4.1 Initial regulatory proposal

In our regulatory proposal, we proposed an estimate the return on equity component of the allowed rate of return having regard to the relevant estimation methods, financial models, market data and other evidence.[663] In particular, our proposed approach:[664]

- identified the relevant rate of return models, namely the SL-CAPM, the Black CAPM, the FFM and the Dividend Discount Model (or, as referred to by the AER, the DGM);

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659 NER, clause 6.5.3.

660 NER, clause 6.4.3(a)(1) and (b)(1).

661 NER, clause 6.5.2(d)(2).

662 NER, clause S6.2.3(c)(3).

663 CitiPower, *Regulatory proposal 2016–2020*, April 2015, chapter 12, p. 197.

664 CitiPower, *Regulatory proposal 2016–2020*, April 2015, chapter 12, p. 197.

- identified the relevant evidence that may be used to estimate the parameters within each of the relevant models;
- estimated model parameters for each relevant model, based on relevant market data and other evidence;
- separately estimated the required return on equity using each of the relevant models; and
- synthesised the results from our modelling as a weighted average of the individual estimates from each relevant model, using weights that avoided double-weighting of any of the key conceptual elements of the models.

In doing so, our proposed approach to estimating the return on equity component of the allowed rate of return represented a reasoned departure from the AER's *Better Regulation, Rate of Return Guideline* dated 17 December 2013 (**RoR Guideline**). The specific departures from the RoR Guideline that we proposed, and the rationale for such departures, were summarised in table 12.7 of our regulatory proposal.[665]

In accordance with our proposed approach, we proposed an estimate of the return on equity of 9.95 per cent (which rounded down to 9.90 per cent using the AER's post-tax revenue model (**PTRM**)).[666] In the alternative, employing the SL-CAPM as a 'foundation' model in accordance with the RoR Guideline, SFG Consulting corrected for two significant flaws in the SL-CAPM and determined an estimate of 9.95 per cent.[667]

10.4.2 AER's preliminary determination

In Attachment 3 to the AER's preliminary determination, the AER adopted its 'foundation model' approach to estimating the return on equity component of the rate of return, in accordance with the RoR Guideline.[668] That approach employed the SL-CAPM as the foundation model. In the AER's view:

- the foundation model approach has regard to relevant estimation methods, financial models, market data and other evidence in a way that contributes to the achievement of the ARORO; and
- on the evidence before it, it was not satisfied that the 'multi-model' approach proposed by various distributors would contribute to the achievement of the ARORO. In particular, the AER concluded that the multi-model approach does not adequately consider the relative merits of each model and introduces a high degree of complexity that reduces transparency and does not provide benefits.

Further, despite having expressly acknowledged that the SL-CAPM 'has weaknesses', the AER nonetheless concluded that:

- the SL-CAPM is superior to all other models for estimating the expected return on equity by reference to the BEE;
- the SL-CAPM was appropriate for use as the foundation model; and
- the use of the SL-CAPM as the foundation model will not result in a downward biased estimate of the return on equity (for the reasons set out in Appendix A of Attachment 3 to the AER's preliminary determination).

Applying the foundation model approach, the AER determined an estimate of the return on equity of 7.3 per cent, which represents a reduction of 2.65 per cent from our proposed estimate.[669] The AER's return on equity

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[665] CitiPower, *Regulatory proposal 2016–2020*, April 2015, pp. 224 - 226.
[666] CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 223.
[667] CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 224.
[668] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-12.
[669] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-12.

point estimate and the various parameter inputs are set out in table 3-2 of the AER's preliminary determination.[670]

The AER considers an equity beta of 0.7, when applied in the SL-CAPM, will deliver a return on equity that contributes to achievement of the ARORO. The AER considers that:[671]

- a reasonable range for the equity beta based on evidence from samples of domestic energy network businesses is 0.4 to 0.7; and
- additional information taken into account by the AER – specifically empirical estimates for international energy networks and the theoretical principles underpinning the Black CAPM – indicate that an equity beta at the top of this range is appropriate.

An MRP of 6.5 per cent reflects prevailing market conditions and contributes to achievement of the ARORO.[672]

The AER determines a 'baseline' estimate of the MRP of 6.0 per cent based on historical data, and then uses DGM analysis and other evidence to determine whether its estimate should be above or below that baseline. The AER considered that DGM evidence could justify a point estimate above the 6.0 per cent baseline, but did not support a point estimate above the top of the range implied by historical excess returns (6.5 per cent).

The AER adopts a different interpretation of some of the empirical evidence to us, including:

- the AER adopts a different interpretation of the historical excess returns data;
- the AER does not agree that the Wright approach should be used to estimate the MRP. This is because the AER considers that the Wright approach is an alternative implementation of the CAPM, designed to produce information at the return on equity level;
- the AER does not agree that independent valuation reports should inform MRP estimation (only the overall return on equity); and
- the AER does not agree with SFG’s construction of the DGM.

The return on equity estimate from the SL-CAPM is broadly supported by:[673]

- estimates using the Wright approach;
- estimates from other market participants, including practitioners and regulators, particularly estimates used in Grant Samuel’s recent report for Envestra;
- the fact that it is above the prevailing return on debt; and
- the fact that the regulatory regime to date has been supportive of investment.

10.4.3 Our response to the AER's preliminary determination

Introduction

The AER’s reasoning is based on a number of errors of fact and logic, which are described in detail below. As a consequence of these errors, the return on equity determined by the AER will not contribute to the achievement of the ARORO and does not reflect prevailing conditions in the market for equity funds. For reasons discussed

[670] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-12.

[671] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-36 to 3-37.

[672] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-35.

[673] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-39 to 3-40.

below, the return on equity derived from the AER's approach will be below what is required to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers.

We continue to believe that the ARORO is best achieved through an approach that properly has regard to estimates from all relevant return on equity models. In our regulatory proposal, we proposed that each of the SL-CAPM, the Black CAPM, the FFM and DGM be estimated, and that these estimates each be given equal weight in deriving a return on equity estimate. We maintain our view that this approach would best achieve the ARORO. This approach leads to an estimate of the prevailing return on equity of 9.8 per cent.

However, if the AER proposes to continue relying solely on the SL-CAPM to estimate the return on equity, the AER must change the way it implements this model. The way in which the SL-CAPM is applied in the AER's preliminary determination leads to a return on equity that is not consistent with the ARORO and does not reflect prevailing market conditions. The AER does not properly recognise the weaknesses of the SL-CAPM, nor does it account for these weaknesses in its application of the model. Further, the AER's practice of applying an effectively fixed risk premium to a variable risk-free rate is not appropriate in current market conditions, since it leads to the return on equity moving in lock-step with changes in the risk-free rate.

Our revised regulatory proposal outlines an alternative approach that involves properly adjusting SL-CAPM (adjusted SL-CAPM) parameters to deliver a return on equity that contributes to the achievement of the ARORO and reflects prevailing market conditions. This involves:

- making a transparent and empirically based adjustment to the equity beta estimate to account for the known shortcomings of the SL-CAPM, particularly low beta bias and book-to-market bias; and
- deriving the MRP in a way that gives appropriate weight to measures of the prevailing (current) MRP.

This leads to an estimate of the prevailing return on equity of 9.9 per cent (based on the 20 business days ending 30 September 2015).

The AER's return on equity estimate is below what is required by the market

The AER's preliminary determination does not point to any genuine consideration of whether the AER's estimate of the return on equity of 7.3 per cent contributes to the ARORO and is commensurate with prevailing market conditions. The AER has rigidly applied its foundation model without proper consideration of whether the output of this model is consistent with the requirements of the Rules.

This is despite evidence, including from the AER's own 'cross-checks', that its return on equity estimate is below the efficient equity financing costs of the BEE and not commensurate with prevailing market conditions.

In particular, the evidence presented in the AER's preliminary determination indicates that:

- the AER's estimate of the return on equity is below any comparable recent estimate from market practitioners. Specifically:
  - the AER's estimate is below the lower end of the range of imputation-adjusted estimates of the return on equity from independent expert reports surveyed by the AER (a range of 8.98 – 14.67 per cent);[674] and
  - the AER's estimate is at the bottom of the range of imputation-adjusted estimates of the return on equity from recent broker reports (a range of 7.3 – 9.3 per cent);[675]

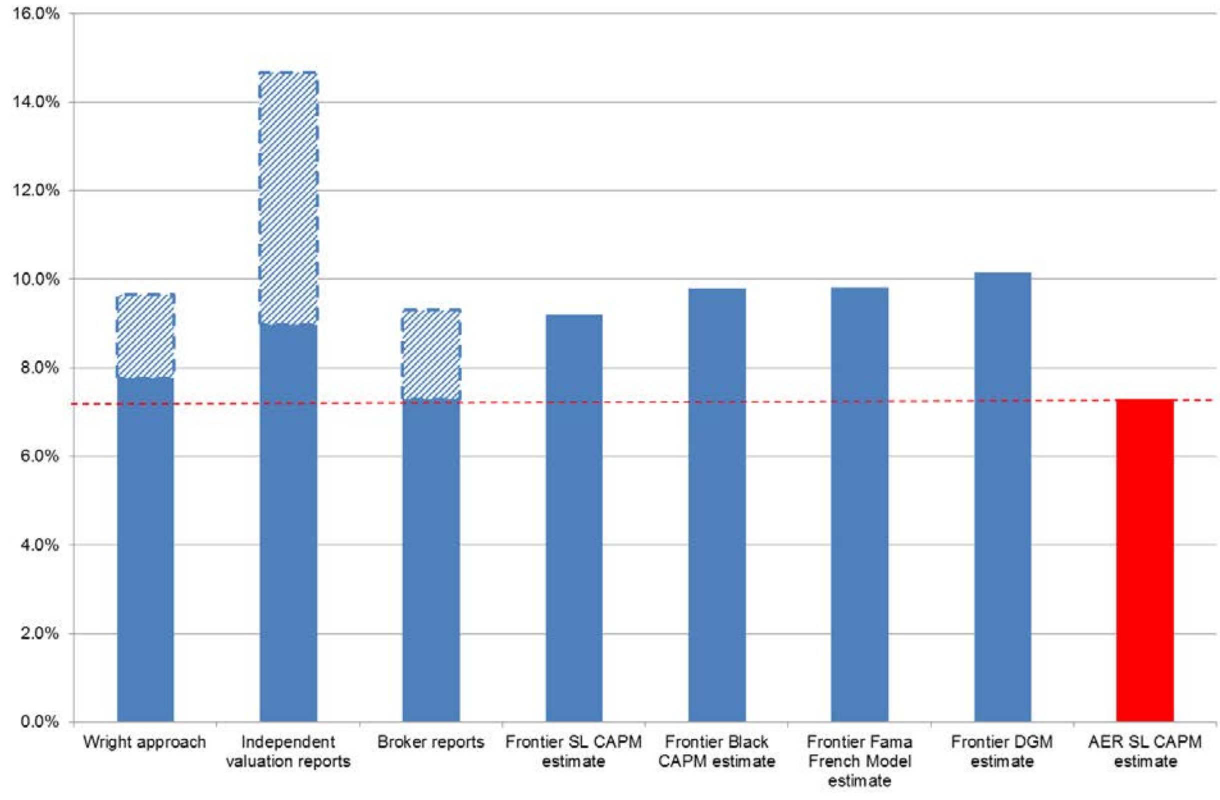
674 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-514.

675 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-517.

- the AER's estimate of the return on equity is below the range indicated by the 'Wright approach'. If properly applied (i.e. with an equity beta that reflects the AER's estimate of this parameter), the Wright approach indicates a range for the return on equity of 7.8 to 9.7 per cent;[676]
- the AER's estimate of the return on equity is below that indicated by current market prices for traded equities and the AER's DGM market-wide analysis. The AER's DGM-based estimates of the MRP implied a range for the market return of 10.26 to 11.36 per cent,[677] which is significantly higher than the AER's implied estimate of the market return of 9.26 per cent;[678] and
- the AER estimate based on its implementation of the SL-CAPM is below estimates from all other relevant return on equity models. Frontier Economics Pty Ltd (**Frontier Economics**) estimates a return on equity of 9.8 per cent using the Black CAPM, 9.8 per cent using the FFM and 10.2 per cent using the DGM, and 9.2 per cent based on its own parameters for the SL-CAPM[679].

The above evidence is summarised in the figure below.

Figure 10.1 Comparison of AER return on equity estimate with other available estimates



Source: CitiPower

676 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-509.

677 The AER's DGM estimates of the MRP range from 7.5 to 8.6 per cent: AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-359. These are added to the risk-free rate of 2.76 per cent to derive estimates of the market return from the AER's DGM.

678 This is calculated as the sum of the risk-free rate (2.76 per cent) and the AER's estimate of the MRP (6.5 per cent).

679 Frontier Economics, *The required return on equity for the benchmark efficient entity*, January 2016, p. 7.

Note: Shaded bars indicate ranges of estimates from broker reports, independent expert reports and the Wright approach.

The outcome observed above is due to the AER mechanistically applying the foundation model approach developed in the RoR Guideline, without any meaningful consideration of whether such an approach leads to an estimate of the return on equity that is consistent with the ARORO and commensurate with prevailing market conditions.

More specifically, this is the result of the AER:

- relying solely on the output of a model that is known to produce biased estimates, without properly correcting for that bias;
- applying this model in a way that does not reflect market practice and which results in the return on equity simply tracking movements in the risk-free rate; and
- making errors in the interpretation of key evidence.

Each of these errors in the AER's approach is addressed in the following sections.

The AER's reliance on the SL-CAPM

The AER concluded that the output of its application of the SL-CAPM should be used as its estimate of the cost of equity, including because:

- the SL-CAPM is the superior model;
- the SL-CAPM, at least as applied by the AER, does not produce biased estimates of the required return on equity; and
- other proposed models are not fit for purpose, including because these other models are focussed on explaining historical market outcomes, rather estimating the required return on equity, consistent with the ARORO.

We consider that each of these critical findings is not consistent with the evidence before the AER.

<u>The AER has erred in finding that the SL-CAPM is the clearly superior model</u>

The AER remains of the view that 'the SL-CAPM is the clearly superior model to use as the foundation model'.[680] However no evidence is cited in support of this statement, and we are not aware of any evidence that supports this view.

The evidence before the AER in fact shows that the SL-CAPM has known weaknesses. In particular, as discussed below, the SL-CAPM is known to produce downwardly biased estimates of the required return on equity for low-beta stocks.

We note that none of the expert reports commissioned by the AER state that the SL-CAPM is superior to other models. We are not aware of any expert report before the AER which expresses this view.

Indeed McKenzie & Partington observe:[681]

> *…the [SL-CAPM] has its weaknesses, but these are well documented and in many cases can either be diagnosed or perhaps compensated for in empirical practice.*

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680 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-529.

681 McKenzie and Partington, *Report to the AER*, *Part A*, *Return on Equity*, October 2014, p. 9.

As discussed below, it is not clear whether the AER has sought to compensate for the known weaknesses of the SL-CAPM, as suggested by McKenzie & Partington, or whether it has simply ignored them. To the extent that the AER has sought to compensate for these weaknesses, by taking the upper bound of its equity beta range, it cannot reasonably be satisfied it has adequately compensated for their effect, because it does not seek to analyse or quantify this effect or meaningfully cross check it against other evidence.

McKenzie & Partington also state:[682]

> *The final estimate of the expected return on equity may have regard to a broad range of relevant material including a range of multifactor models such as the Fama and French (1993) and the APT of Ross (1976), inter alia. Many of these competing models nest this foundation model and so potentially make more use of available information.*

Certainly McKenzie and Partington do not appear to view the SL-CAPM as superior to all other models. Rather they acknowledge the weaknesses of the model and recommend that any estimate of the return on equity may take into account a wider range of models, including the FFM.

Associate Professor Handley also acknowledges the critical weakness of the SL-CAPM, noting:[683]

> *An apparent weakness of the Sharpe-CAPM is the empirical finding, for example by Black, Jensen and Scholes (1972) and Fama and French (2004), that the relation between beta and average stock returns is too flat compared to what would otherwise be predicted by the Sharpe-CAPM – a result often referred to as the low beta bias.*

The weaknesses and limitations of the SL-CAPM were identified in our regulatory proposal and the supporting expert reports. In particular, SFG referred to the large body of empirical evidence which shows that the SL-CAPM will tend to produce biased estimates of the required return on a low-beta or value stock, and may not fully capture all factors affecting stock returns.[684] SFG's reports also explained how other models such as the Black CAPM and FFM were developed specifically to overcome these known weaknesses in the SL-CAPM design.[685]

Some of the key empirical evidence demonstrating weakness in the SL-CAPM is summarised in the table below.

Table 10.5 Summary of key empirical evidence in relation to SL-CAPM performance

Study	Key conclusions
Black, Jensen and Scholes (1972)686	Black, Jensen and Scholes (1972) tested the SL-CAPM theory against empirical data. Their results indicated that the empirical relationship between systematic risk exposure and returns was not consistent with SL-CAPM theory. The relationship in the empirical data indicated a higher intercept and flatter slope than that indicated by the SL-CAPM. The authors conclude that their results appeared to be strong evidence favouring rejection of the traditional form of the asset pricing model (i.e. the SL-CAPM).

682 McKenzie and Partington, *Report to the AER*, *Part A*, *Return on Equity*, October 2014, p. 9.

683 Handley, *Advice on the Return on Equity*, *Report prepared for the Australian Energy Regulator*, 16 October 2014, p. 5.

684 SFG, *The required return on equity for regulated gas and electricity network businesses*, June 2014 at [46] to [60].

685 See, for example: SFG, *The required return on equity for regulated gas and electricity network businesses*, June 2014; SFG, *The cost of equity in the Black Capital Asset Pricing Model*, 22 May 2014; SFG, *The Fama-French model*, 13 May 2014.

686 Black, Jensen, and Scholes, *The Capital Asset Pricing Model, Some empirical tests*, in Studies in the Theory of Capital Markets, Michael C. Jensen, ed., New York: Praeger, 1972, pp. 79 - 121, referred to in SFG, *The required return on equity for regulated gas and electricity network businesses*, 6 June 2014, pp. 20 - 22.

Study	Key conclusions
Friend and Blume (1970)[687]	The empirical analysis by Friend and Blume (1970) indicates that low-beta stocks generate higher returns than the SL-CAPM would suggest and high-beta stocks tend to generate lower returns than the SL-CAPM predicts.
Fama and Macbeth (1973)[688]	Fama and Macbeth (1973) empirically test the assumption of the SL-CAPM that the return on a zero-beta asset will be equal to the risk-free rate. Consistent with the earlier findings of Black, Jensen and Scholes (1972), they conclude that this assumption is not supported by the empirical data.
Rosenberg, Reid and Landstein (1985)[689]	The study by Rosenberg, Reid and Landstein, as well as other studies identified a number of SL-CAPM anomalies, where stock-specific characteristics seemed related to differences in returns. In particular, the book equity value divided by the market equity value (book-to-market ratio) appeared to be related to variation in returns.
Fama and French (1992)[690]	Fama and French (1992) demonstrated relationships between returns and book-to-market and size factors which are not accounted for in the SL-CAPM.
Brealey, Myers and Allen (2011)[691]	A recent study by Brealey, Myers and Allen confirms the findings of earlier studies, such as the study by Black, Jensen and Scholes (1972), that the pattern of empirical data is not consistent with what the SL-CAPM would predict.
Brailsford, Gaunt and O'Brien (2012)[692]	Brailsford, Gaunt and O'Brien (2012) provide evidence, using Australian data, that value stocks tend to earn higher returns than the SL-CAPM predicts should be the case and growth stocks tend to earn less than the SL-CAPM predicts should be the case. The evidence that Brailsford, Gaunt and O'Brien (2012) provide indicates that the SL-CAPM underestimates the returns required on value stocks and overestimates the returns to growth stocks.
NERA (2015)[693]	Based on Australian data, and using both in-sample and out-of-sample tests, NERA conclude that there is evidence of bias in the SL-CAPM. NERA states that the evidence indicates that the SL-CAPM significantly underestimates the returns generated by low-beta portfolios and overestimates the returns generated by high-beta portfolios. In other words, the model has a low-beta bias. The extent to which the SL-CAPM underestimates the returns to low-beta portfolios is both statistically and economically significant.

Source: CitiPower

[687] Friend and Blume, 'Measurement of Portfolio Performance under Uncertainty', American Economic Review, 60, 1970, pp. 561-75, referred to in SFG, *The required return on equity for regulated gas and electricity network businesses*, 6 June 2014, pp. 22-23.

[688] Fama and MacBeth, 'Risk, return, and equilibrium, Empirical tests', Journal of Political Economy, 81, 1973, pp. 607-636, referred to in SFG, *The required return on equity for regulated gas and electricity network businesses*, 6 June 2014, pp. 23-24.

[689] Rosenberg, Reid, and Lanstein, 'Persuasive evidence of market inefficiency', Journal of Portfolio Management 11, 1985, pp. 9 to 17, referred to in SFG, *The Fama-French model: Report for Jemena Gas Networks, ActewAGL, Transend, TransGrid, and SA PowerNetworks*, 13 May 2014, p. 15.

[690] Fama and French, 'The cross-section of expected stock returns', Journal of Finance 47, 1992, pp. 427-466, referred to in SFG, *The Fama-French model: Report for Jemena Gas Networks, ActewAGL, Transend, TransGrid, and SA PowerNetworks*, 13 May 2014.

[691] Brealey, Myers, and Allen, *Principles of Corporate Finance*, 10th ed., McGraw-Hill Irwin, New York, NY, USA, 2011, referred to in SFG, *The required return on equity for regulated gas and electricity network businesses*, 6 June 2014, p. 24.

[692] Brailsford, Gaunt and O'Brien, 'Size and book-to-market factors in Australia', Australian Journal of Management, 2012, pp. 261-281, referred to in NERA, *Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama-French Three-Factor Model*, March 2015.

[693] NERA, *Empirical Performance of Sharpe-Lintner and Black CAPMs*, February 2015.

The body of empirical literature relating to identified weaknesses in the SL-CAPM, and the development of alternative models to overcome the well-recognised deficiencies in this model, is discussed at some length by the Nobel Prize Committee, in the explanatory material accompanying the award of the Nobel Prize for contributions to this field.[694] The Committee observes that by the end of the 1970s, the empirical support for the SL-CAPM was increasingly being questioned in a number of studies, including those referred to above.

In light of the above evidence, the AER cannot rationally conclude that the SL-CAPM is superior to all other models. The evidence clearly shows that the SL-CAPM has weaknesses and that there are alternative models available, some of which have been designed to address such weaknesses.

<u>The AER has erred in finding that its implementation of the SL-CAPM will produce unbiased estimates</u>

The AER considers the issue of potential bias in the SL-CAPM in the AER's preliminary determination, but concludes:[695]

> *We do not consider the use of the SLCAPM as the foundation model will result in a downward biased estimate of the cost of equity capital.*

Elsewhere in the AER's preliminary determination, the AER states that:[696]

> *There is no compelling evidence that the return on equity estimate from the SLCAPM will be downward biased given our selection of input parameters.*

It is not entirely clear from these statements whether the AER has found that:

- in general, the SL-CAPM will produced unbiased estimates of the required return on equity (Finding 1); or
- to the extent that the SL-CAPM may produce biased estimates, the AER's selection of input parameters adequately corrects for any bias (Finding 2).

It must be that the AER has made either Finding 1 or Finding 2, in order for it to be satisfied that its approach will deliver a return on equity which contributes to achievement of the ARORO.

Empirical evidence does not support Finding 1

We consider that Finding 1 would involve a critical error of fact. Empirical evidence clearly demonstrates that the SL-CAPM will lead to downwardly biased estimates of the return on equity for low-beta stocks. This empirical evidence is referred to in a number of the expert reports supporting our regulatory proposal, including:

- expert reports from SFG, referring to the early empirical analysis of SL-CAPM performance which laid the foundations for the development of alternative models such as the Black CAPM and FFM. This included the work of Black, Jensen and Scholes (1972), Friend and Blume (1970) and Fama and Macbeth (1973) referred to above;[697] and
- NERA's comprehensive review of the empirical literature on the performance of the SL-CAPM and alternative models. NERA concludes from its review of the SL-CAPM literature:[698]

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[694] Economic Sciences Prize Committee of the Royal Swedish Academy of Sciences, *Understanding Asset Prices: Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013*, 14 October 2013, section 7.

[695] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-130.

[696] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-62.

[697] SFG, *The required return on equity for regulated gas and electricity network businesses*, June 2014 at [46] to [60].

[698] NERA, *Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama-French Three-Factor Model,* March 2015, p. iii.

It has been known for well over 40 years that empirical versions of the SL-CAPM tend to underestimate the returns to low-beta assets and overestimate the returns to high-beta assets…

These early results have been confirmed in many, more recent studies. These studies have also shown that the SL-CAPM tends to underestimate the returns to value stocks and low-cap stocks.

Further evidence of bias in SL-CAPM estimates of the return on equity is provided by the recent analysis of NERA, using Australian data.[699] NERA concludes that the evidence indicates that the SL-CAPM significantly underestimates the returns generated by low-beta portfolios and overestimates the returns generated by high-beta portfolios. In other words, the model has a low-beta bias. The extent to which the SL-CAPM underestimates the returns to low-beta portfolios is both statistically and economically significant.

The AER's only response to this in its preliminary determination was to observe that the results of NERA's analysis 'appear counterintuitive'.[700] This is not a proper basis for simply dismissing this very important piece of analysis. The fact that NERA's results were contrary to the AER's prior intuition is unsurprising, given that the AER may have expected the empirical relationship between beta and stock returns to reflect what is predicted by the SL-CAPM. The fact that the empirical results were not consistent with the predictions of the SL-CAPM is not a reason to dismiss the empirical analysis. Rather, this ought to have confirmed for the AER what the previous studies had indicated – that there is a significant weakness in the SL-CAPM, in terms of its performance against the empirical data – or at least put the AER on notice that further genuine investigation is needed.

In dismissing the NERA analysis and earlier studies, the AER also refers to advice from Partington, which it considers supports a finding that the SL-CAPM will not produce downwardly biased estimates. However the Partington advice referred to by the AER does not address the empirical evidence of low-beta bias in the SL-CAPM (i.e. evidence that the SL-CAPM underestimates the return on equity for stocks with a beta below one). Rather, in the passage referred to by the AER, Partington addresses an entirely separate issue of whether there may be a theoretical or statistical justification for adjusting equity beta estimates to account for statistical bias. The AER has misinterpreted the advice of its expert on this point.

There is no basis for Finding 2

The AER has not sought to advance any reasoned or principled basis for Finding 2 and, in any event there can be no reasonable basis for such a finding. The AER does not seek to quantify the effect of such bias, nor does it make any transparent adjustment to its SL-CAPM parameter estimates to correct for bias.

The AER does make an adjustment to its equity beta estimate, from what it refers to as 'the best empirical estimate' of this parameter. However it is not clear whether this adjustment is intended to correct for bias in the SL-CAPM. In any event, given that the AER does not seek to quantify the effect of SL-CAPM bias, it cannot reasonably be satisfied that this adjustment adequately corrects for such bias.

Indeed, the AER appears to acknowledge that its equity beta estimate should be adjusted upwards to correct for bias in the SL-CAPM, but says it cannot ascertain by how much it needs to adjust its estimate because it does not empirically estimate the Black CAPM. The AER does not calculate a specific uplift to its beta to correct for SL-CAPM bias, but instead makes an arbitrary upward adjustment in the hope that this will adequately account for the issue that it has identified. The AER states:[701]

We consider the theoretical principles underpinning the Black CAPM demonstrate that market imperfections could cause the true (unobservable) expected return on equity to vary from the SLCAPM estimate. For firms

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699 NERA, *Empirical Performance of Sharpe-Lintner and Black CAPMs*, February 2015.

700 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-284.

701 AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 3-493.

with an equity beta below 1.0, the Black CAPM may predict a higher expected return on equity than the SLCAPM. We use this theory to inform our equity beta point estimate, and consider it supports an equity beta above the best empirical estimate implied from Henry's 2014 report. However, while the direction of this effect may be known, the magnitude is much more difficult to ascertain. We do not consider this theory can be used to calculate a specific uplift to the equity beta estimate to be used in the SLCAPM. This would require an empirical implementation of the Black CAPM, and we do not give empirical evidence from the Black CAPM a role in determining the equity beta for a benchmark efficient entity.

Ultimately, the AER adopts the top of its selected range for the SL-CAPM equity beta – in effect, the AER makes an upward adjustment to the equity beta, from what it refers to as the 'best empirical estimate' to the upper limit of its range. However given that the AER has not sought to quantify the effect of SL-CAPM bias, it cannot reasonably be satisfied that choosing the top of its equity beta range will adequately correct for such bias.

We consider that selecting the top of the AER's equity beta range will not adequately correct for the bias in the SL-CAPM indicated by Black CAPM theory. If the AER's parameter estimates are used in the Black CAPM along with the best available estimate of the zero-beta premium, the return on equity estimated by the Black CAPM is above the return on equity estimated by the AER using the SL-CAPM (and adopting the upper limit of its equity beta range).[702]

The following table shows that even if the AER's lower bound beta value is used in the Black CAPM, the resulting return on equity estimate is still above the AER's SL-CAPM estimate using the upper bound beta value. If the AER's 'best empirical estimate' of beta is used in the Black CAPM, the resulting return on equity estimate is significantly above the AER's SL-CAPM estimate. This indicates that if the AER were to properly adjust its SL-CAPM beta estimate to account for the bias in the SL-CAPM indicated by Black CAPM theory, the resulting beta would need to be higher than 0.7.

Table 10.6 Comparison of SL-CAPM and Black CAPM return on equity estimates[703]

Model	Return on equity estimate
SL-CAPM – equity beta 0.7; MRP 6.5%	7.3%
Black CAPM – equity beta 0.4 (AER lower bound); MRP 6.5%	7.4%
Black CAPM – equity beta 0.5 (AER 'best estimate'); MRP 6.5%	7.7%
Black CAPM – equity beta 0.7 (AER upper bound); MRP 6.5%	8.3%

Source: CitiPower

If the SL-CAPM is to be used alone to estimate the return on equity, some adjustment needs to be made to its input parameters to account for the known weaknesses of the model. If the SL-CAPM is used without any adjustment, the empirical evidence shows that the return on equity for low-beta stocks will be significantly under-estimated.

Our concern is that the AER's adjustment to the equity beta is not sufficient to account for the known weaknesses of the SL-CAPM. As shown above, even if the AER's view as to the 'best empirical estimate' of equity beta were to be accepted (noting we do not agree with this, for reasons set out under the heading 'Equity beta

702 Zero-beta premium of 3.34 per cent, as estimated by SFG (SFG, *Cost of equity in the Black Capital Asset Pricing Model*, 22 May 2014, section 4).

703 All calculations are based on a risk-free rate of 2.76 per cent (as used in the AER's preliminary determination) and a Black CAPM zero-beta premium of 3.34 per cent (as estimated by SFG – see: SFG, *Cost of equity in the Black Capital Asset Pricing Model*, 22 May 2014, section 4).

estimate' below), it is clear that adjusting the equity beta upwards to 0.7 does not account for the bias in the SL-CAPM.

For our revised regulatory proposal, we put forward an alternative method for estimating the return on equity using the SL-CAPM alone, with an empirically based adjustment to account for the known weaknesses of this model. This alternative method is explained under the heading 'An alternative implementation of the foundation model approach' below and the accompanying expert report from Frontier Economics.

<u>The AER has erred in its findings in relation to other available models</u>

The AER raises a number of concerns with the other available return on equity models. Given these concerns, the AER decides to give these alternative models either no role in its determination of the return on equity, or a very limited role.

The key concerns raised by the AER are:

- alternative models are sensitive to input assumptions and choices around estimation periods and methodologies;
- some alternative models are not empirically reliable;
- some alternative models are not designed to estimate ex ante returns;
- some alternative models (particularly the FFM) lack theoretical foundation;
- some alternative models (particularly the Black CAPM) are not widely used by market practitioners, academics or regulators; and
- some alternative models produce return on equity estimates that appear 'very high'.

For reasons discussed below, we consider that each of these concerns is unfounded. In several cases, the AER's method and reasons for rejecting this other evidence (or relegating it to an indirect role) are illogical and unreasonable and/or apply equally to the SL-CAPM.

Complexity and sensitivity of models to assumptions

A key concern raised by the AER in relation to alternative return on equity models is that they are sensitive to inputs assumptions and methodological choices. For example the AER considers that the DGM is highly sensitive to assumptions around the growth rate of dividends.[704] In relation to the FFM, the AER identifies a range of different methodological choices which might lead to different results.[705]

Simply observing that a return on equity model is sensitive to input assumptions and methodological choices does not provide a basis for rejecting that model or giving it a very limited role. All return on equity models—including the SL-CAPM—are sensitive to input assumptions. This is why it is important to estimate all model parameters as accurately as possible.

The same concern could be expressed in relation to the SL-CAPM. Clearly the results produced by the SL-CAPM could vary widely depending on one's choice of input parameters and the methodologies used to estimate those parameters. Just based on the AER's ranges for the equity beta and MRP set out in the AER's preliminary determination (and holding the risk-free rate constant), the return on equity produced by the SL-CAPM could range from 4.8 per cent to 11.4 per cent.[706] This wide range of values arises due to different approaches that

[704] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-79.

[705] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-73.

[706] That is, adopting a range for the MRP of 5.0 per cent - 8.6 per cent and a range for the equity beta of 0.4 – 0.7.

could be taken to estimating the MRP, and different methodological and data choices which could be made in estimating the MRP or beta.

Grant Samuel, in its submission in response to the NSW draft decisions, expressed concern at the AER's unbalanced treatment of the DGM and SL-CAPM in this regard. Grant Samuel notes:[707]

> *The DGM, in its simplest form, has only two components to estimate – current dividend yield and the long term growth rate for dividends. The current yield is a parameter that can be estimated with a reasonably high level of accuracy, particularly in industries such as infrastructure and utilities. We accept that the question of the long term dividend growth rate becomes the central issue and is subject to a much higher level of uncertainty (including potential bias from sources such as analysts) and we do not dispute the comments by Handley on page 3-61.*
>
> *However, there is no way in which the issues, uncertainties and sensitivity of outcome are any greater for the DGM than they are with the CAPM which involves two variables subject to significant measurement issues (beta and MRP).*

Dr Robert Malko, a regulatory expert in the United States of America (where the DGM is frequently used) similarly notes:[708]

> *Certainly the DGM is sensitive to its input assumptions and if it would be inappropriately implemented, it could deliver implausible results. In this regard, I see no difference between this and other models. If inappropriate inputs are used, any of the models can produce implausible results.*
>
> *It is common in United States regulatory determination processes for there to be debate between businesses, customers and the regulators concerning which inputs to use but these debates occur with a context in which expert testimony has regard to whether the inputs used deliver plausible results and decision making is guided by a body of court and regulatory precedent.*
>
> *Over-all, the wide acceptance and use of the DGM in the United States demonstrates that this model is sufficiently robust for it to be useful in economic regulatory decision making.*

For the reasons expressed by Dr Malko, we consider that the sensitivity of a model to input assumptions should not be a reason for dismissing it.

Reliability of empirical estimates

A particular concern raised by the AER in relation to the Black CAPM is that estimates of the return on equity will be unreliable, because there is no reliable method to obtain an estimate of the zero-beta premium.

The AER's concern appears to be that, because different estimation techniques have produced varying estimates of the zero-beta premium, it cannot rely on any empirical estimates of this parameter. The AER states:[709]

> *We consider SFG's latest estimate of the zero beta premium appears more plausible. However, we remain of the view that the large range of zero beta estimates by consultants indicates that the model is unsuitable for estimating the return on equity for the benchmark efficient entity.*

Besides noting that it is 'plausible', the AER has not sought to test the robustness or reliability of SFG's proposed value for the zero-beta premium. Instead, the AER has dismissed SFG's estimate on the basis that there are other differing estimates, some of which are 'implausible'.

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707 Samuel, *Grant Samuel response to AER draft decision*, 12 January 2015, p. 3.

708 Statement of Dr J Robert Malko, 16 June 2015, p. 5.

709 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-310.

We consider that this is an illogical and unreasonable approach to assessment of the proposed Black CAPM parameter values and return on equity estimate. The AER cannot reasonably conclude that all estimates of the zero-beta premium are unreliable, just because some estimates of this parameter appear implausible. The same logic could be used to dismiss just about any return on equity model, including the SL-CAPM, to the extent that some estimates of the MRP or equity beta are considered unreliable.

This is particularly so given that detailed and compelling explanations have been provided as to why SFG's estimate differs from other estimates of the zero-beta premium. As explained by SFG, recent empirical studies have demonstrated the significance of the book-to-market factor in explaining variation in stock returns in Australia. It is for this reason that the SFG study, unlike earlier studies of the zero-beta premium, controls for this factor in the estimates. SFG controls for this by forming portfolios that have approximately the same composition in terms of book-to-market ratio and other relevant firm characteristics.[710] As is clear from SFG's explanations, the difference between their estimates of the Black CAPM zero-beta premium and earlier estimates does not indicate that the model is empirically unreliable – rather, it reflects a development in the methodology for estimating this parameter.

We propose to use SFG's estimates of the zero-beta premium and required return on equity from the Black CAPM in estimating the return on equity. If the AER is to reject this proposal, it must first consider SFG's estimates and assess whether adopting these estimates would (either alone or in combination with other models or methods) contribute to the achievement of the ARORO. The AER cannot simply reject our proposal on the basis that there are other estimates of Black CAPM parameters (which we have not sought to rely on) which the AER considers to be implausible.

Instead of seeking a reliable estimate of the Black CAPM zero-beta premium, the AER has effectively assumed this to be zero (by relying solely on the SL-CAPM to estimate the return on equity). We consider that this is an unreasonable approach, in circumstances where the AER has identified the Black CAPM to be a relevant model. Given that the Black CAPM is clearly a relevant model, a proper examination should be undertaken of what the best estimate for the zero-beta premium is and this value should be used.

Lack of theoretical foundation

The AER has again raised a concern in relation to the theoretical foundation for the FFM.

This concern has been addressed in our regulatory proposal and the supporting expert reports of SFG and NERA.[711]

As explained by SFG, the basis for development of the FFM was in studies documenting the empirical failings of the SL-CAPM.[712] These studies documented that when the stock market index is used as the only factor (as in the SL-CAPM), the model does not fit the data, but when the additional FFM factors (size and book-to-market ratio) are included the model does fit the data better. These early findings have been confirmed by more recent

[710] SFG, *Beta and the Black Capital Asset Pricing Model*, February 2015 at [65]; SFG, *Cost of equity in the Black Capital Asset Pricing Model,* 22 May 2014, section 4.

[711] SFG, *The Fama-French model*, 13 May 2014, pp. 27 to 30; SFG, *Using the Fama-French model to estimate the required return on equity,* February 2015; NERA, *Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama-French Three-Factor Model*, March 2015, section 2.3.

[712] SFG, *The Fama-French model*, 13 May 2014, pp. 27 - 30; SFG, *Using the Fama-French model to estimate the required return on equity,* 13 February 2015.

analysis using Australian data. A recent study shows that while the size factor in not significant in the Australian data, the book-to-market factor is.[713]

The general theoretical foundation for the FFM is the same as for the SL-CAPM, in that both models posit that there is a linear relationship between the expected return of a particular stock and the expected return of a mean-variance efficient portfolio.[714]

Where the theory of the FFM differs from SL-CAPM theory is that in the FFM non-diversifiable risk is proxied by three factors, rather than one factor as implied by SL-CAPM theory. The three factors posited by FFM theory are:[715]

- the excess return to the market portfolio;
- the difference between the return to a portfolio of high book-to-market stocks and the return to a portfolio of low book-to-market stocks (HML); and
- the difference between the return to a portfolio of small-cap stocks and the return to a portfolio of large-cap stocks (SMB).

The theoretical and empirical foundation for the FFM is discussed at some length by the Nobel Prize Committee, in the explanatory material accompanying the award of the Nobel Prize to Eugene Fama for contributions to this field.[716]

Models not designed to estimate ex ante returns

The AER expresses a concern in relation to the FFM that the model 'is not clearly estimating ex ante required returns'.[717]

It is curious that this criticism is only levelled at the FFM, given that theoretical foundation for the FFM is the same as for other asset pricing models, including the SL-CAPM and Black CAPM. The key objective of all asset pricing models is to explain the cross section of stock returns, based on explanatory factors (such as market risk in the case of the SL-CAPM) that have been observed to correlate with stock returns in the past. The basis for development of the FFM (and also the Black CAPM) was in studies documenting the failure of the SL-CAPM to adequately explain variations in returns.

The reason for using any asset pricing model is that the historically observed relationships between returns, risk and other factors may be expected to continue in future. In this regard, the rationale for using the FFM is no different to the rationale for using the SL-CAPM or Black CAPM.

As noted above, empirical analysis using Australian data shows that there is a statistically and economically significant relationship between returns and book-to-market ratios. Given the significance of this relationship in the historic data, and thus its explanatory power, there is no reason to expect that it would not continue in future. The AER's position on this topic is akin to saying that a prediction that the sun will rise tomorrow is not an

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713 Brailsford, T., C. Gaunt, and M. O'Brien (2012), 'Size and book-to-market factors in Australia', *Australian Journal of Management*, 37, pp. 261 - 281.

714 SFG, *The Fama-French model*, 13 May 2014, p. 27.

715 NERA, *Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama-French Three-Factor Model*, March 2015, p. 17.

716 Economic Sciences Prize Committee of the Royal Swedish Academy of Sciences, *Understanding Asset Prices: Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013*, 14 October 2013, section 7.

717 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-70.

'ex ante analysis of expected behaviour' if it is based on observations that the sun has always risen in the past. Inductive reasoning is neither weak nor, of itself, lacking in predictive power.

Models not widely used

The AER's concern that alternative models are not widely used was also addressed in our regulatory proposal and supporting expert reports. We observe that while some of these models are yet to gain acceptance among Australian regulators, it is clear that they are widely used by academics, market practitioners and overseas regulators and that they are market respected.

Our position on this issue is further reinforced by recent evidence, including evidence of the use of models other than the SL-CAPM in the United States of America (US).

Dr Robert Malko states, in relation to regulatory practice in the US:[718]

> *I have observed that in the United States regulators and expert financial witnesses generally use multiple methods, at least two, when determining a reasonable range and reasonable point estimate for the cost of common equity for a regulated energy utility.*

Specifically in relation to the Black CAPM, Dr Malko states:[719]

> *… although there is little explicit reference to the Black CAPM, in practice the use in the U.S. of the Empirical CAPM by financial analysts both within and outside energy regulatory processes is essentially to the same effect.*

Dr Malko explains that the 'Empirical CAPM', as referred to in US practice, involves a higher intercept and flatter relationship between returns and beta than under the SL-CAPM.[720] Thus, the Empirical CAPM as used in US practice is consistent with the theory of the Black CAPM.

This is consistent with evidence from SFG that both the Black CAPM and DGM are commonly used in rate of return regulation cases in other jurisdictions.[721] SFG also notes that the FFM, while not as widely used in regulatory practice, is widely used by market practitioners and is well recognised in academic literature.[722]

'Very high' return on equity estimates

A further concern raised by the AER in relation to the DGM is that:[723]

> *The very high return on equity estimates from SFG's DGM model, equating to an equity beta of 0.94 in the SLCAPM, appear inconsistent with the results in Professor Olan Henry's 2014 report.*

The AER appears to be suggesting that, because the return on equity estimates produced by the DGM are higher than those produced by the SL-CAPM (with the AER's preferred parameter values), the DGM estimates cannot be relied on.

This is an irrational and illogical approach to assessing the reliability of DGM estimates of the return on equity. This approach assumes that the SL-CAPM estimates are accurate and reliable, and thus can be used as the benchmark to test the plausibility or reliability of estimates from other models. Adopting similar logic, one could

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718 Statement of Dr J Robert Malko, 16 June 2015, p. 10.

719 Statement of Dr J Robert Malko, 16 June 2015, p. 8.

720 Statement of Dr J Robert Malko, 16 June 2015, p. 8.

721 SFG, *The required return on equity for regulated gas and electricity network businesses*, 6 June 2014, p. 40.

722 SFG, *The Fama-French model*, 13 May 2014, pp. 17 - 22.

723 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-319 to 3-320.

conclude that the SL-CAPM is unreliable because it produces estimates that are 'very low' when compared to the DGM and any other models that produce higher estimates.

Alternatively, it may be that the AER considers that an implied equity beta of 0.94 would be 'too high', because it is above its own estimate of that parameter. However there are two problems with such reasoning:

- first, this assumes that the AER's equity beta analysis is correct, and that any estimate which differs from its estimate of 0.7 (or falls outside its determined range of 0.4 – 0.7) must be incorrect. The AER appears to consider that its estimate is more likely to be correct, because it accords with its assumption that energy businesses are in general 'low risk'.

  However, simply asserting that energy businesses are generally 'low risk' does not provide a basis for preferring one equity beta estimate over another, particularly where both of these estimates are less than one. If the AER believes that energy network businesses are 'low risk', all this would indicate is that the equity beta is likely to be less than one.

  In any event, we do not agree that low elasticity of demand for energy services indicates that network businesses are 'low risk'—which is the AER's key reason for arguing that they are. It is well recognised that the relevant risks to a business include both operating and financial risks. Even if the AER considers the operating risk of energy networks to be relatively low (compared to the average firm), it must be recognised that financial risk is relatively high, due to high leverage when compared to the average firm in the market. Therefore the AER cannot reasonably conclude that overall, energy network businesses are 'low risk'.[724] One would need to test empirically the relative importance of operating and financial risks when assessing overall risk.

- second and more fundamentally, there is an implicit assumption that the SL-CAPM will deliver unbiased estimates of the return on equity. If the SL-CAPM is in fact delivering downwardly biased estimates (as indicated by the empirical evidence referred to above) then the implied equity beta needed to deliver a DGM-equivalent result must include an uplift to account for this bias. In other words, if there is a bias in the SL-CAPM that is not accounted for in the AER's equity beta of 0.7, this will contribute to a higher equity beta being needed to deliver a DGM-equivalent result.

The AER is required to have regard to all relevant estimation methods, financial models, market data and other evidence.[725] The AER cannot reject relevant financial models simply on the basis that the results they produce are inconsistent with the results of the AER's preferred model. Where two or more relevant models produce conflicting results, it is incumbent on the AER to assess each of the models on their merits and on that basis decide how their results are to be taken into account in determining the return on equity.

When faced with two models which produce differing results there are three possible hypotheses:

- the model producing the lower estimate is accurate and unbiased, while the other model is upwardly biased or has been incorrectly applied;
- the model producing the higher estimate is accurate and unbiased, while the other model is downwardly biased or has been incorrectly applied; or

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724 This issue is discussed further in the ENA's submission to the AER equity beta issues paper (ENA, *Response to the Equity Beta Issues Paper of the Australian Energy Regulator*, 28 October 2013, pp. 14 - 20) and in a recent report from Frontier Economics (Frontier, *Review of the AER's conceptual analysis for equity beta*, June 2015).

725 NER, clause 6.5.2(e)(1).

- there is a degree of error or imperfection in both models, and the correct outcome lies somewhere between or outside the two.

The AER has clearly not tested these possible hypotheses. Rather, the AER appears to have assumed that the first hypothesis is correct – i.e. that the SL-CAPM is reliable and the DGM is not – without any rational basis. This is despite other evidence that suggests that either the second or third hypothesis is more likely to be correct. As noted above, there is empirical evidence that the SL-CAPM will produce downwardly biased estimates of the SL-CAPM for low-beta stocks.

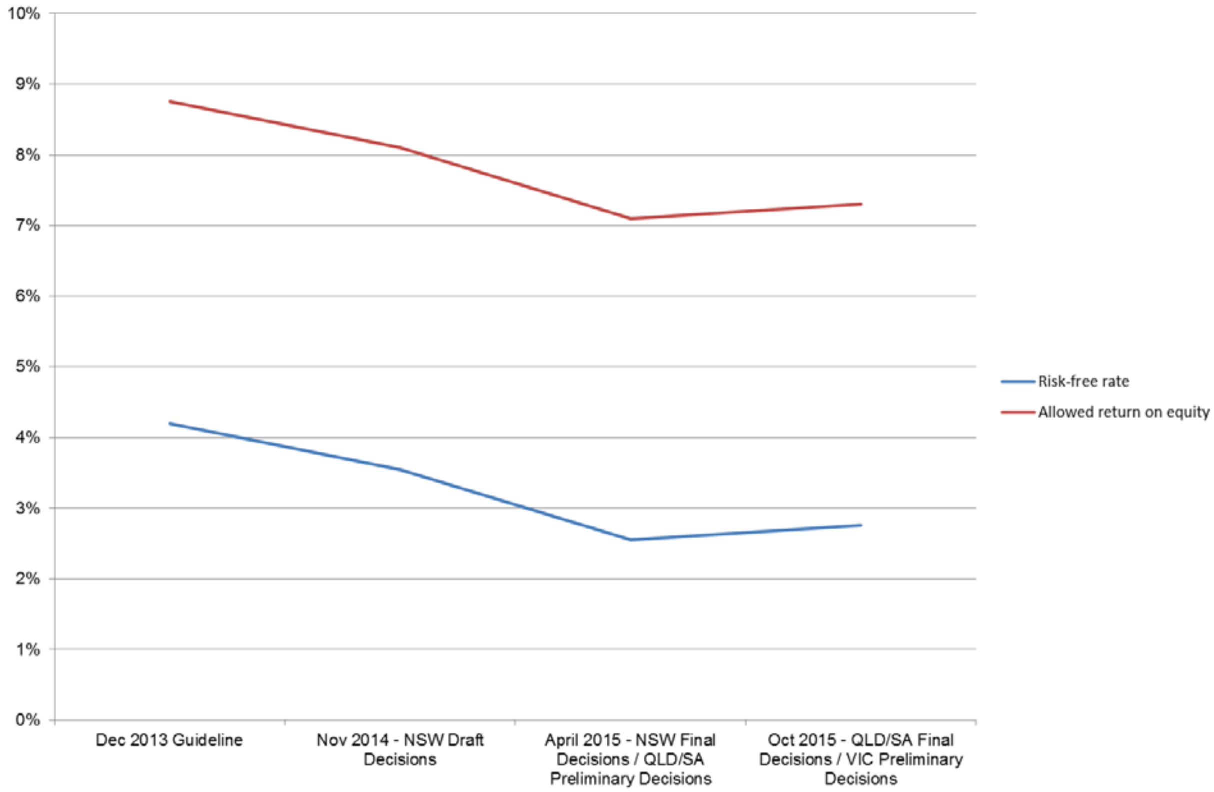
In any event, it is not clear that the DGM return on equity estimate is 'very high', when compared to the results of other relevant models and the AER's cross-checks. When comparing the outputs of the four relevant models, it could rather be said that the SL-CAPM estimate appears 'very low' when compared to the results of the other three models (see under heading 'The AER's return on equity estimate is below what is required by the market' above).

The AER's application of the SL-CAPM

The AER's mechanistic application of the SL-CAPM

The AER continues to apply the SL-CAPM in a largely mechanistic manner, by adding an effectively fixed equity risk premium (**ERP**) to a variable risk-free rate. The result is that over the past two years the AER's return on equity estimate has moved in lock-step with the risk-free rate, as shown in the figure below.

Figure 10.2 Movement in the allowed return on equity under AER application of the SL-CAPM



Source: AER

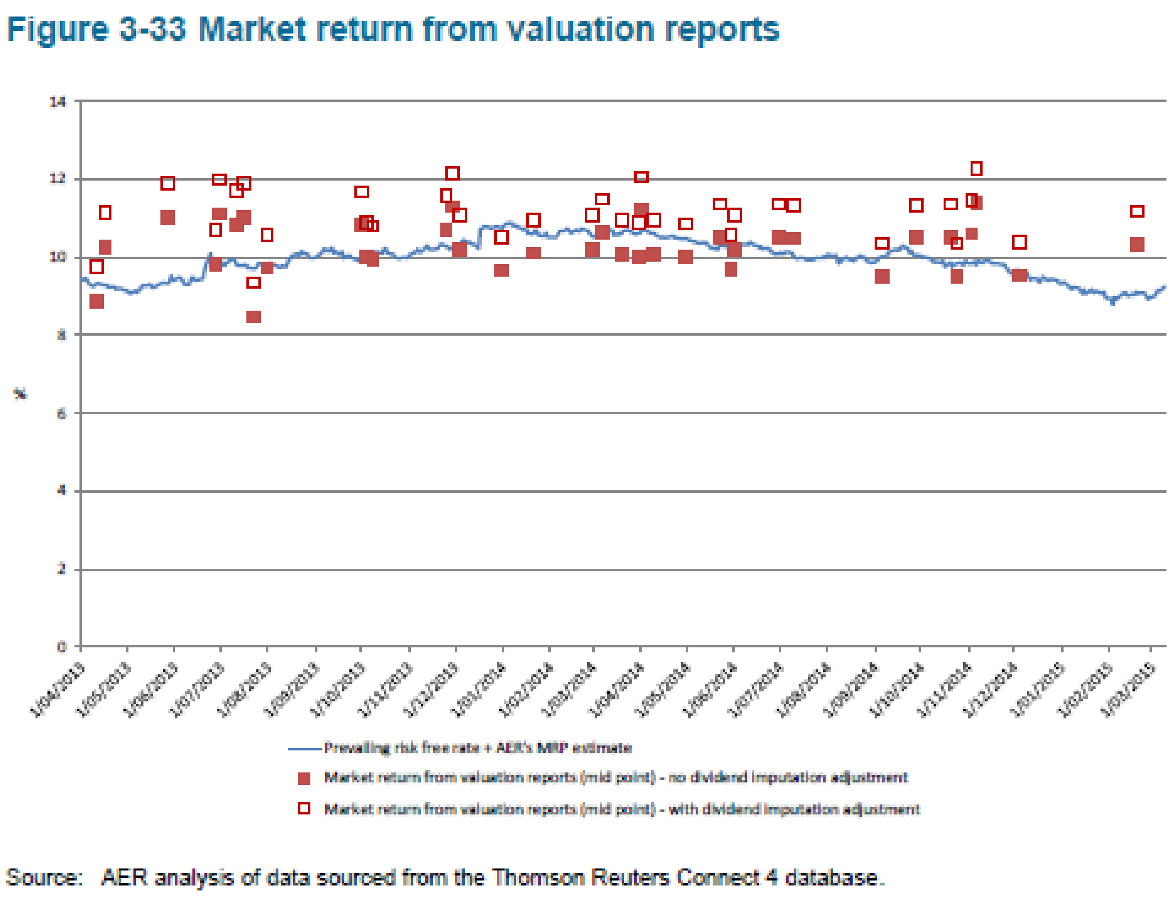
This approach is at odds with evidence that the MRP has increased as the risk-free rate has fallen, including the evidence from the AER's own DGM. This evidence is discussed further below.

It is also at odds with how the SL-CAPM is applied by market practitioners.

In an expert report that was submitted with our regulatory proposal, Incenta Consulting Group (**Incenta**) explained that as the risk-free rate has fallen over the past 18 months, the vast majority of independent expert reports have adjusted either the risk-free rate and/or MRP upwards.[726] The AER's approach of maintaining the same MRP estimate and combining this with a falling risk free rate is inconsistent with this observed market practice.

This market evidence is consistent with that presented by the AER in its preliminary determination.[727] The AER's analysis of independent expert reports (figure 3-33 of the AER's preliminary determination) indicates that as the risk-free rate has fallen over the past two years, estimates of the market return in independent expert reports have remained relatively steady. This can be contrasted with the AER's assumption (as illustrated by the blue line in figure 3-33) that over this period the market return has fallen in lock-step with the risk-free rate.

Figure 10.3 Market return from valuation reports



Source: AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-351 (Figure 3-33)

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726 Incenta, *Further update on the required return on equity from independent expert reports*, February 2015.

727 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-531.

The AER's analysis also indicates that independent experts have tended to increase their estimates of the ERP when the risk-free rate is low. Figure 3-32 in the AER's preliminary determination indicates that, based on the AER's review of independent expert reports:[728]

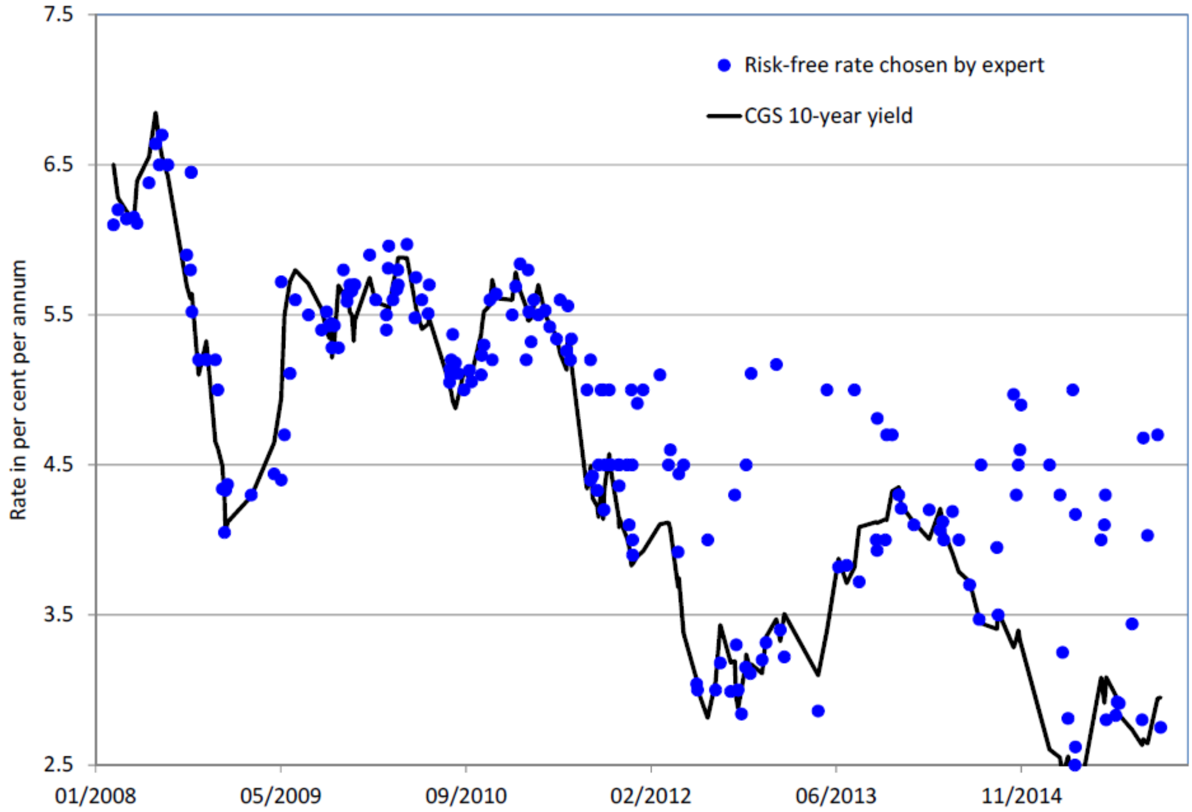
- independent experts estimated the ERP to be in the range of 4 – 6 per cent (not adjusted for imputation credits) when the risk-free rate is in excess of 5 per cent; and
- independent experts estimated the ERP to be in the range of 9.5 – 11.5 per cent (not adjusted for imputation credits) when the risk-free rate is below 3 per cent.

The AER's analysis of independent expert reports is confirmed by more recent analysis from HoustonKemp. As noted above, HoustonKemp observes that in recent times a number of independent experts have used risk-free rates above the prevailing CGS yield, leading to more stability in their estimates of the prevailing market return (and implicitly higher MRP assumptions) than under the AER's approach.[729] This is shown in the figure below. This evidence suggests that market practitioners do not believe that the return on equity has simply been moving in lock-step with the risk free rate in recent years.

[728] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-530 (Figure 3-32).

[729] HoustonKemp, *The Cost of Equity: Response to the AER's draft decisions for the Victorian Electricity Distributors*, *ActewAGL Distribution and Australian Gas Networks*, January 2016, p 43 and Figure 7.

Figure 10.4 Risk-free rates chosen by independent experts and 10-year CGS yield over time[730]



Note: Data are from the Connect-4 database, the ASX and the RBA. The 10-year CGS yields are interpolated from the RBA files f16.xls, f16hist.xls and f16hist2013.xls.

Source: HoustonKemp, *The Cost of Equity: Response to the AER's draft decisions for the Victorian Electricity Distributors, ActewAGL Distribution and Australian Gas Networks*, January 2016.

An assumption that the return on equity moves in lock step with CGS yields is inappropriate in current market conditions. Further evidence provided with this revised regulatory proposal demonstrates that the recent decline in CGS yields has been driven by factors which would not be expected to affect the return on equity to the same extent. Frontier Economics notes that declines in CGS yields have been attributed to unprecedented monetary easing by central banks and a shortage of risk-free assets as demand for these assets has increased. Frontier Economics notes that at least some of these factors appear to be unique to the government bond market and therefore would not be expected to affect the return on private equity – for example, tighter banking regulations have increased the demand for government bonds but not equity, and the demand from foreign investors has been much more pronounced in the government bond market than the equity market.[731] Further, Frontier Economics points to empirical evidence that the return on equity has not fallen in lockstep with the decline in government bond yields.[732]

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[730] HoustonKemp, *The Cost of Equity: Response to the AER's draft decisions for the Victorian Electricity Distributors, ActewAGL Distribution and Australian Gas Networks*, January 2016.

[731] Frontier Economics, *The relationship between government bond yields and the market risk premium*, January 2016, pp 28-29.

[732] Frontier Economics, *The relationship between government bond yields and the market risk premium*, January 2016, pp 30-31.

CEG points to evidence from numerous Australian and international authorities that yields on AAA rated sovereign government debt (including CGS) have been forced down in recent years by global forces, including:[733]

- shrinking supply of AAA rated Sovereign debt globally and shrinking supply of substitutes in the form of safe private sector debt;
- heightened relative risk aversion and increased levels of perceived relative risk for equity vis-à-vis government debt; and
- heightened demand for liquid assets post Global Financial Crisis (**GFC**) - including due to changes to banking regulations.

CEG explains that none of these factors that have lowered CGS yields would be expected to also lower the return on equity. CEG concludes:[734]

> *None of these factors can be expected to lower the cost of equity for private corporations. Consequently, to the extent that these factors do explain, at least in part, unprecedented low government bond yields then it follows that the cost of equity will not have fallen in line with falling government bond yields. This is just another way of saying that the risk premium, measured relative to government bond yields, will have risen.*

Determination of the MRP

The AER's decision on the MRP

In the AER's preliminary determination, the AER adopted a three-step approach to estimating the MRP:[735]

- in step one, the AER determined a 'baseline' estimate for the MRP, based on estimates of historical excess returns. The AER considered that the information on historical excess returns indicated a baseline estimate for the MRP of 6.0 per cent. This baseline estimate was taken from a range of estimates of historical excess returns of 5.0 per cent to 6.5 per cent;[736]
- in step two, the AER had regard to DGM evidence in order to determine whether it should select an MRP point estimate above or below the baseline estimate of 6.0 per cent. The AER's DGM estimates of the MRP ranged from 7.5 to 8.6 per cent and its preferred three-stage estimates ranged from 7.7 to 8.6 per cent.[737] The AER considered that this information could justify a point estimate above the 6.0 per cent baseline, but did not support a point estimate above the top of the range implied by historical excess returns (6.5 per cent);[738] and
- in step three, the AER placed some reliance on survey evidence and conditioning variables. The AER considered that this information, in conjunction with DGM evidence, helps to indicate how far above or below the baseline estimate the MRP point estimate should be.

The effect of adopting this three-step approach is that critical evidence as to the prevailing MRP, from the AER's DGM model, has very little influence on the determination of the point estimate. This evidence is only used to indicate whether the prevailing MRP is likely to lie above or below the AER's 'baseline' estimate of 6.0 per cent, which reflects the AER's view of the historical average MRP. The estimates from the AER's DGM model do not

733 CEG, *Measuring risk free rates and expected inflation*, April 2015, p. 1.

734 CEG, *Measuring risk free rates and expected inflation*, April 2015, p. 2.

735 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-428.

736 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-425.

737 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-359.

738 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-430.

appear to otherwise influence the AER's determination of the MRP. Ultimately, the AER's estimate of the prevailing MRP is based on historical average measures, and evidence as to the prevailing MRP is only used to determine which of the historical average measures is used.

We are concerned that the MRP estimate resulting from this approach will not reflect prevailing market conditions. The evidence before the AER (including from the AER's own DGM analysis) indicates that the prevailing MRP is not in line with the historical average. Despite this, the AER has tied its estimate of the MRP to the range of historical average measures. Measures of the prevailing MRP are only used to determine which historical average measure is to be used.

The AER's DGM estimates do not merely indicate that the MRP is somewhere above 6.0 per cent. Rather, the AER's DGM estimates indicate that the current MRP is somewhere in the range of 7.5 to 8.6 per cent. This evidence in no way confirms or supports the AER's estimate of 6.5 per cent.

It appears that the AER has incorrectly analysed the range for the historical average MRP as suggesting that the prevailing MRP could be found in this range, whereas all that this range indicates is that the MRP in average market conditions (i.e., the average of the market conditions over the historical period that was used) had a range of somewhere between 5.0 to 6.5 per cent. Consequently, the AER fails to appreciate that the best estimate of the prevailing MRP need not fall within the statistical range of estimates for the historical average excess return – for example, if the contemporaneous market conditions differed from the historical average conditions because the risk-free rate was at unprecedented lows.

The AER also appears to have constrained its consideration of the appropriate MRP through its three-step approach. Through its consideration of historical excess return estimates in step one, the AER appears to have constrained the range of possible MRP outcomes to that indicated by its range of estimates for the historical average excess returns (5.0 to 6.5 per cent). Consequently, the evidence considered under step two (the AER's DGM estimates) could only have an effect on the determination of the MRP to the extent that it confirmed an estimate within the range determined under step one. To the extent that this evidence indicated an estimate outside this range, it was given no weight, or its role was limited to taking the AER to the top of the range defined by step one.

Rigidity of the AER's MRP estimate, despite evidence of changes in market conditions

We note that the AER's estimate of the MRP has not changed since publication of its RoR Guideline, despite apparent changes in prevailing market conditions. The AER adopted an estimate for the MRP of 6.5 per cent in its ROR Guideline, and has maintained the same MRP estimate in the draft and final decisions for the NSW electricity distributors (November 2014 and April 2015) and in its preliminary determination (October 2015). The AER's view appears to be that there has been no change to the MRP between December 2013 and October 2015.

However the evidence before the AER indicates that there has been a significant change in market conditions over the past two years. In particular indicators of the forward-looking MRP – including the AER's own DGM results – indicate that the MRP has increased significantly. Whereas at the time of the RoR Guideline the AER's MRP estimate sat within the AER's range of DGM estimates, by the time of the AER's preliminary determination, the AER's MRP estimate was well outside its range of DGM estimates. In December 2013, the AER estimated a range for the MRP of 6.1 – 7.5 per cent from its DGM.[739] However, in the AER's preliminary determination, this range is 7.5 to 8.6 per cent.[740]

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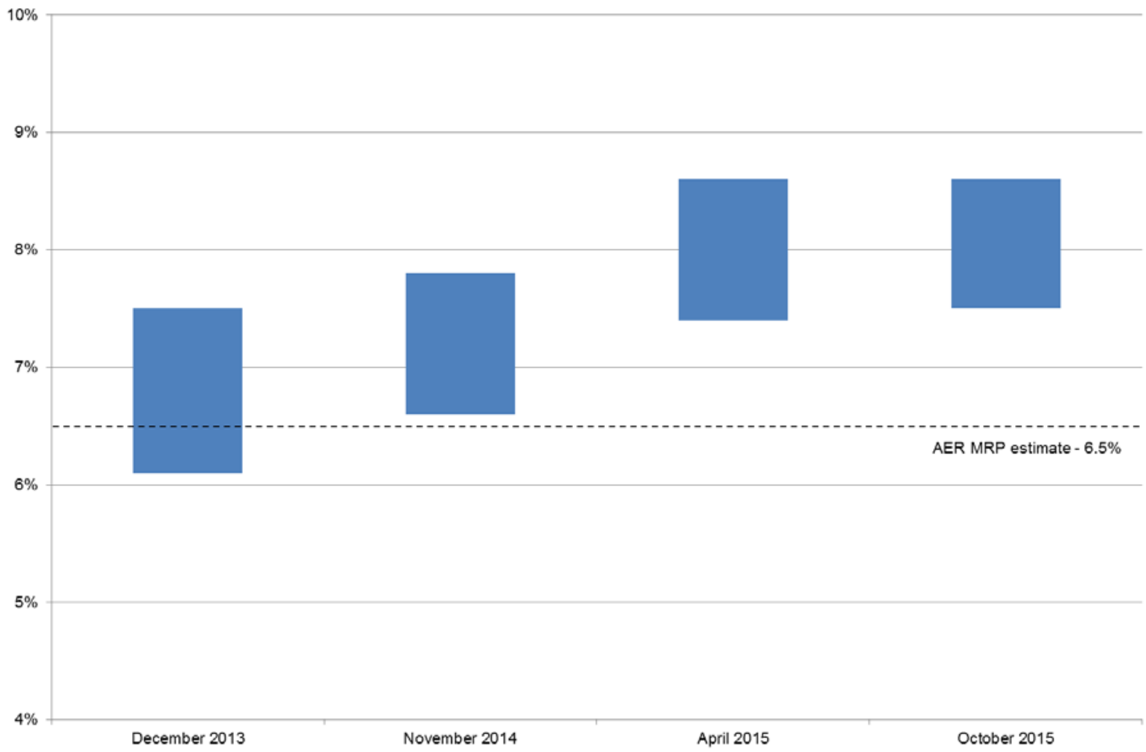
[739] AER, *Better Regulation, Explanatory Statement, Rate of Return Guideline*, December 2013, p. 93.

[740] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-359.

Figure 10.5 Movement in AER DGM estimates since RoR Guideline



Source: AER

The fact that the AER's MRP has not changed despite significant increases in its DGM estimates suggests that either the AER is placing no real weight on DGM results, or the AER has placed declining weight on these results as the MRP estimate has increased. Giving either no weight or declining weight to DGM results would be unreasonable in circumstances where DGM results provide the best indicator of the current (prevailing) MRP. This implies that the AER is giving increasing weight to historical average measures of the MRP, which will not reflect prevailing market conditions except perhaps by chance (i.e. if, by chance, current market conditions reflect historical average conditions).

Further, there has been a precipitous fall in the risk-free rate – from around 4.2 per cent at the time of the RoR Guideline, to around 2.76 per cent at the time of the AER's preliminary determination. By holding the MRP constant, the AER implicitly assumes that the market conditions driving this reduction in CGS yields are:

– not affecting the MRP at all; and

– leading to a corresponding one-for-one reduction in the return on equity.

As noted above, the evidence does not support such an assumption. Rather, the evidence from the AER's own DGM analysis indicates that the MRP has been increasing as the risk-free rate has been falling, and that as a result, the return on equity has not fallen in lock-step with the risk-free rate.

- As discussed below (under the heading 'Reasonableness of the overall outcome'), evidence from the AER's cross check analysis and conditioning variables points to an increase in the MRP.
- It has been recognised by market practitioners and regulatory authorities that current market conditions are not average market conditions, and that the MRP is likely deviating from a fixed range based on historical average measures.

For example, as noted in our regulatory proposal, the United States Federal Energy Regulatory Commission has noted:[741]

Given the recent trends of near-historic low yields for long-term U.S. Treasury bond rates, the CAPM's input for the "risk-free" rate, we find that it is a reasonable assumption that the current equity risk premium (which is added to the risk-free rate to calculate the cost of equity data point that determines the slope of the CAPM curve) exceeds the 86-year historical average used as the consultants' CAPM input. The current low treasury bond rate environment creates a need to adjust the CAPM results, consistent with the financial theory that the equity risk premium exceeds the long-term average when long-term U.S. Treasury bond rates are lower than average, and vice-versa.

Similarly in the UK, Ofgem has recognised that as the risk-free rate has fallen to historic lows, it is not appropriate to simply add a prevailing risk-free rate measure to a fixed ERP. Ofgem has instead used a risk-free rate range above the prevailing rate, resulting in more stability in estimates of the overall return on equity. Ofgem explains its approach as follows:[742]

Market measures of the real risk-free rate, such as the yield on ILGs, have risen slightly since the data cut-off point for EE's December report. However, they remain near historical lows, partly due to the Bank of England's official interest rate being held at 0.5 per cent and the impact of Quantitative Easing. We, therefore, do not consider it appropriate to rely on spot rates or short-term averages to set the risk-free rate.

Our revised range for the risk-free rate is, therefore, 1.7-2.0 per cent. The lower bound matches the 10-year average yield on 10-year ILGs, while the upper bound corresponds to regulatory precedent in the UK.

The RBA has observed that the ERP appears to have risen as the risk-free has fallen in recent years. The RBA Governor observed in a recent speech:[743]

…another feature that catches one's eye is that, post-crisis, the earnings yield on listed companies seems to have remained where it has historically been for a long time, even as the return on safe assets has collapsed to be close to zero... This seems to imply that the equity risk premium observed ex post has risen even as the risk-free rate has fallen and by about an offsetting amount.

In an Australian regulatory context, the Economic Regulation Authority in Western Australia (**ERA**) has recognised that the MRP will fluctuate over time, and that it is therefore not appropriate to fix a range for the MRP. The ERA noted in a recent decision:[744]

…the Authority has now concluded that it is not reasonable to constrain the MRP to a fixed range over time. The erratic behaviour of the risk free rate in Australia to date, and more particularly, its pronounced decline in the current economic environment, leads to a situation where the combination of a fixed range for the MRP and prevailing risk free rate may not result in an outcome which is consistent with the achievement of the average market return on equity over the long run.

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741 Federal Energy Regulatory Commission, Order accepting tariff filing subject to condition and denying waiver, Docket No. ER14-500-000, 28 January 2014, p. 36.

742 Ofgem, *RIIO-T1: Final proposals for National Grid Electricity Transmission and National Grid Gas Transmission*, 17 December 2012, p. 33. See also: Oxera, *Agenda – Advancing economics in business - What WACC for a crisis?*, February 2013, for a review of recent UK regulatory decisions on this issue.

743 Stevens, 'The World Economy and Australia', Address to The American Australian Association luncheon, hosted by Goldman Sachs, New York, USA, 21 April 2015.

744 ERA, *Final Decision on Proposed Revisions to the Access Arrangement for the Mid-West and South-West Gas Distribution Systems submitted by ATCO Gas Australia Pty Ltd*, 30 June 2015 (as amended on 10 September 2015), p. 251.

Specifically, the estimate of the upper bound for the forward looking MRP of 7.5 per cent that was based on the DGM will fluctuate in line with the risk free rate. So for example, at times when the risk free rate is low, as it currently is, the upper bound for the MRP should be higher. There will be times – such as during the GFC – when the Authority would be more likely to select a point estimate of the MRP which is close to the upper bound. The resulting required return on the market in that type of situation could possibly exceed the long run average return on equity indicated by the historical data.

For this reason the Authority considers it appropriate to determine a range for the MRP at the time of each decision.

The approach taken in our proposal to estimating the MRP takes into account changes in prevailing market conditions. Each of the estimation methodologies can be updated for recent data in order to derive a current estimate of the MRP.

However, we are concerned that the AER's methodology is not similarly responsive to changes in market conditions. This is likely to be due to the fact that, as discussed below, the AER's approach fails to take into account a number of relevant estimation methodologies which will provide an indication of current market conditions, such as the Wright approach and evidence from independent expert reports.

Errors in interpretation of key evidence

The AER's conclusion on the MRP is also affected by errors in the interpretation of key evidence.

(A) *Historical excess returns*

The AER refers to a range for the historical average MRP of 5.0 – 6.5 per cent, based on a combination of geometric and arithmetic average measures.

There are two problems with the AER's interpretation of the historical data:

- first, the AER has mixed geometric average measures with arithmetic averages, in addition to mixing estimates for different time periods. Expert advice, including advice from NERA and Lally, explains why geometric averages are not an appropriate measure in this case. As explained by NERA, since estimates of the MRP are not compounded, arithmetic mean measures should be used;[745]
- secondly, the AER has relied on estimates from Brailsford, Handley and Maheswaran which rely on an historical dataset that has been inappropriately adjusted to take account of perceived deficiencies in the original dataset. These adjustments have been investigated by NERA and the adjustments to the original dataset corrected. This issue was addressed at length in our regulatory proposal, and in the accompanying expert reports from NERA. The key issue is that the adjustment originally made to the historical data appears to have had no logical basis. It follows that an examination of earlier data extracted from original sources (as has been done by NERA) will almost surely lead to an adjustment that is more accurate than the one contained in the data that Brailsford, Handley and Maheswaran employ.[746]

Based on a correct interpretation of the historical data and with appropriate adjustments for imputation, the historical average MRP based on the longest available dataset is 6.56 per cent (based on a theta of 0.35).[747] We

745 NERA, *Historical Estimates of the Market Risk Premium*, February 2015, section 2.

746 NERA, *Historical Estimates of the Market Risk Premium*, February 2015; NERA, *Further Assessment of the Historical MRP: Response to the AER's Final Decisions for the NSW and ACT Electricity Distributors*, June 2015.

747 NERA, *Historical Estimates of the Market Risk Premium*, February 2015, p. 42.

note that, if the AER's theta estimate of approximately 0.6 were to be used, this MRP estimate would increase slightly, to 6.65 per cent.[748]

(B) *The AER has incorrectly used the Wright approach*

The AER does not take into account the Wright approach when estimating the MRP, because it considers that the Wright approach should inform the overall return on equity only. The AER refers to the Wright approach as an alternative implementation of the SL-CAPM designed to provide information at the return on equity level.[749]

This is an incorrect interpretation of Wright's work. Wright did not develop an alternative implementation of the SL-CAPM. Wright simply proposed an alternative method of estimating the MRP for use in the SL-CAPM – as the difference between the historical average market return and the current risk free rate – on the basis that market returns may be more stable over time than excess returns.[750]

Associate Professor Handley, in a passage referred to in the AER's preliminary determination, clearly describes the Wright approach as an alternative method of estimating the MRP, rather than as an alternative return on equity model. Handley describes the Wright approach as follows:[751]

> *Wright adopts an alternative non-standard approach to estimating the MRP. Rather than treating the MRP as a distinct variable he suggests estimating the return on the market – by estimating the real return on equity and combining this with a current forecast of inflation to give an estimated nominal return on equity – and the risk free rate separately.*

In the AER's preliminary determination, the AER sets out a formula, which it says represents the Wright approach to implementing the SL-CAPM (referred to by the AER as the 'Wright SLCAPM').[752] However, the formula set out by the AER is simply the standard SL-CAPM, as originally specified by Sharpe and Lintner[753] It is clear from this that the Wright approach does not involve an alternative model for estimating the overall return on equity. Rather, the Wright approach represents an alternative method for estimating the MRP parameter.

In fact, the Wright approach to estimating the MRP would appear to be more aligned with the conventional SL-CAPM specification, because it seeks to estimate the MRP as the difference between two distinct parameters (the market return and risk-free rate). This is in contrast to other methods which seek to estimate the MRP as a parameter in its own right.

It is therefore incorrect for the AER to reject the Wright approach on the basis that it is not a measure of the MRP. The Wright approach clearly provides relevant information in relation to the required market return and the MRP, and it would be an error for the AER to disregard it when estimating the MRP.

(C) *Use of independent valuation reports*

The AER considers independent valuation reports to be relevant, but only to assessing the overall return on equity. Further, due to perceived limitations, the AER considers that only 'limited reliance' should be placed on this material, and that it should be used in a 'directional role' only.[754]

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748 NERA, *Historical Estimates of the Market Risk Premium*, February 2015, p. 43.

749 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-33.

750 Wright, *Review of Risk Free Rate and Cost of Equity Estimates: A Comparison of U.K. Approaches with the AER*, 25 October 2012.

751 Handley, Advice on the Return on Equity, 16 October 2014, p. 17; AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-88.

752 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-84 to 3-85.

753 Sharpe, 'Capital asset prices: A theory of market equilibrium under conditions of risk', Journal of Finance, 19, 1964, pp. 425 - 442.

754 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-95.

Ultimately it is not clear what practical effect, if any, independent valuation reports have on the AER’s decision on the return on equity. As a consequence of their relegation to an overall return on equity 'check' role, they appear to have little or no practical impact on the final estimate. The AER retains its original parameter estimates and model choice once it completes its cross-check against the results of independent expert reports.

We consider that independent valuation reports provide relevant evidence of the required market return and MRP applied by market practitioners. Therefore, evidence from these reports as to the MRP applied by market practitioners should be given a direct role in estimating the MRP.

Incenta’s February 2015 analysis of independent expert reports indicates that the market rate of return estimated by independent experts has remained relatively constant in recent times, notwithstanding declines in the ‘spot’ risk free rate.[755] This implies that the MRP used in these reports, and/or the uplifts used by independent experts, has increased as the risk-free rate has declined.

This is consistent with evidence presented by the AER in its preliminary determination.[756] As noted above, the AER’s analysis of independent expert reports (figure 3-33 of the AER's preliminary determination) indicates that as the risk-free rate has fallen over the past two years, estimates of the market return in independent expert reports has remained relatively steady at around 11 per cent (adjusted for imputation). This can be contrasted with the AER’s estimate of the market return, which has declined to around 9 per cent, moving in lock-step with changes in the risk-free rate.

These findings are supported by more recent analysis from HoustonKemp. As noted above, HoustonKemp observes that in recent times a number of independent experts have used risk-free rates above the prevailing CGS yield, leading to more stability in their estimates of the prevailing market return (and implicitly higher MRP assumptions) than under the AER’s approach.[757]

HoustonKemp identifies a statistically significant negative relationship between the implied MRP estimated by experts (their implied estimate of the market return, less the prevailing CGS yield) and the prevailing CGS yield.

Based on their analysis of recent independent expert reports, HoustonKemp estimates an implied MRP from these reports of 7.58 per cent.[758]

(D) *Use of DGM estimates*

The AER adopts a different construction of the DGM to that used by SFG and Frontier Economics, and as a result derives a wider range of estimates for the market return and MRP.

SFG and Frontier Economics have clearly explained each of the points of difference between its approach and the AER’s, and explains why it has taken the approach that it has.[759] In particular, SFG and Frontier Economics clearly explain the reasons for their choice of long term growth assumption, estimation approach and dataset. For the

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755 Incenta, *Further update on the required return on equity from independent expert reports*, February 2015.

756 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-531.

757 HoustonKemp, *The Cost of Equity: Response to the AER's draft decisions for the Victorian Electricity Distributors*, *ActewAGL Distribution and Australian Gas Networks*, January 2016.

758 HoustonKemp, T*he Cost of Equity: Response to the AER’s Draft Decisions for the Victorian Electricity Distributors, ActewAGL Distribution and Australian Gas Networks*, January 2016, p 48. This estimate is inclusive of a value assigned to imputation credits distributed, where it is assumed that theta is 0.35. HoustonKemp notes that if a higher theta value were to be assumed, its estimate of the MRP based on this analysis would be higher (assuming theta of 0.6 leads to an estimate of 8.02%). HoustonKemp’s estimate of 7.58% is exclusive of any final revisions or adjustments made by independent experts. If revisions / adjustments are included, the estimate would be higher (HoustonKemp’s estimate increases to 7.94%, if these revisions / adjustments are included0.

759 SFG, *Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network*, February 2015.

reasons set out in SFG's report, we consider that the SFG and Frontier Economics approach to implementing the DGM is clearly preferable to the AER's.

However even adopting the AER's preferred construction of the DGM, it is clear that the MRP has increased significantly over the past two years. The table below shows the change in the MRP from the AER's DGM between the RoR Guideline and the AER's preliminary determination (October 2015).

Table 10.7 AER dividend growth model estimates of the required return on the market

	Growth rate (%)	Two stage model (%)	Three stage model (%)
RoR Guideline	4.0	6.1	6.7
	4.6	6.7	7.1
	5.1	7.1	7.5
AER's preliminary determination	4.0	7.5	7.7
	4.6	8.1	8.2
	5.1	8.5	8.6

Source: RoR Guideline, Appendices, p. 87; AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-359.

Frontier Economics' estimate of the prevailing MRP (discussed below) uses the AER's DGM estimate based on its preferred three-stage model and the mid-point of its range of growth rate assumptions. This estimate is currently 8.2 per cent, as shown in the table above.

<u>Conclusion on the MRP</u>

For the above reasons, we do not agree with the AER's estimate for the MRP of 6.5 per cent. This estimate does not reflect prevailing conditions in the market for equity funds and will not contribute to the achievement of the ARORO. The AER's decision on the MRP is affected by a number of errors, as described above.

We consider that a preferable approach is that set out by Frontier Economics. This approach takes into account all relevant evidence on the MRP and applies a transparent weighting to each estimate based on the relative strengths and weaknesses of each estimation approach. The reasons for Frontier Economics' weighting approach are set out in an expert report by SFG submitted with our regulatory proposal.[760]

Importantly, Frontier Economics' approach gives greatest weight to measures of the prevailing (current) MRP. This is in contrast to the AER's approach which leads to an MRP estimate that reflects an historical average measure.

Frontier Economics has now updated its estimate of the MRP based on current data. Frontier Economics' revised estimate is set out in the following table.

[760] SFG, *The required return on equity for regulated gas and electricity network businesses*, June 2014.

Table 10.8 Frontier Economics' estimates of MRP (per cent)

Estimation method	Market return	MRP	Weighting
Historical excess returns (Ibbotson)	9.3	6,5	20
Historical real market returns (Wright)	11.4	8.6	20
Dividend discount model	11.0	8.2	50
Independent expert reports	10.3	7.6	10
Weighted average	10.6	7.9	100

Source: Frontier Economics, *The required return on equity under a foundation model approach*, January 2016, Table 4. The risk-free rate assumed in these calculations is a placeholder estimate, based on a September averaging period.

Equity beta estimate

The AER concludes that an equity beta of 0.7, when applied in the SL-CAPM, will deliver a return on equity that contributes to achievement of the ARORO. The AER finds that:

- the primary range for the equity beta should be based on analysis of Australian regulated energy businesses only;
- based on analysis of this sample, a reasonable range for the equity beta is 0.4 to 0.7;
- 'the best empirical estimate' of the equity beta is 0.5; and
- additional information taken into account by the AER – specifically empirical estimates for international energy networks and the theoretical principles underpinning the Black CAPM – indicate that an equity beta at the top of this range is appropriate, and will overcome any bias in the SL-CAPM.

This section addresses each of these findings.

The AER has erred in confining the sample to Australian regulated businesses

The AER's primary range for the equity beta is based on analysis of a very small data sample comprising listed Australian energy network businesses only. This sample includes nine businesses, of which just four are currently trading.

It is neither necessary nor appropriate to confine the sample used for estimating equity beta to regulated energy network businesses only. As discussed in the overview, the relevant degree of risk under the ARORO is that faced by entities operating in a workably competitive market providing services similar to electricity distribution services within Australia. Therefore, in constructing comparator datasets for the purposes of estimating a return on equity that is commensurate with efficient financing costs of a BEE, these datasets should include entities operating in workably competitive markets that face a similar degree of risk to that faced in the provision of electricity distribution services. That is, they should not be restricted to regulated entities.

Even if the relevant level of risk is that of a regulated energy network business subject to economic regulation under the Rules, in many cases it will be necessary to look beyond just those businesses that supply regulated energy network services within Australia in order to produce sufficiently large datasets for robust estimation of risk parameters. For reasons discussed below, this is most clearly the case in relation to the equity beta.

A sample of nine regulated energy network businesses is very small. However the fact that five of these businesses are no longer trading creates further problems, since the data for these non-trading businesses becomes 'stale' over time. The equity beta estimates for these non-trading businesses will reflect the risks faced by those businesses in the past, not the risks currently faced by a BEE. As noted in our regulatory proposal, the level of risk faced in the supply of energy network services is changing, with businesses facing new operational risks arising from disruptive technologies. This change in risk profile is discussed in the accompanying expert report of Frontier Economics.[761]

The expert evidence before the AER demonstrates that the sample used by the AER is too small to provide statistically reliable estimates. Analysis by SFG demonstrates that:[762]

- Professor Henry's estimates based exclusively on the small sample of domestic energy network businesses are statistically unreliable.[763] SFG and Frontier Economics note that the estimates are imprecise with wide standard errors, the estimates span a wide range, and the results were sensitive to the choices of estimation method, sampling frequency and time period.[764] The figure below shows the wide confidence intervals around Professor Henry's estimates, and the wide range of individual company estimates based on just one methodology and sampling technique. Professor Henry reports some evidence of instability in his study based on Australian data only, possibly due to the small sample size;[765] and
- increasing sample size significantly reduces the dispersion of estimates. Previous analysis by SFG (2013) and Brooks, Diamond, Gray and Hall (2013) demonstrated that increasing sample size from nine to 18 firms is likely to reduce the dispersion of risk estimates by about one-third, and increasing sample size further to 27 firms is likely to reduce this estimation error by half.[766]

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761 Frontier, *Review of the AER's conceptual analysis for equity beta*, June 2015, section 3.

762 SFG, *Regression-based estimates of risk parameters for the benchmark firm*, 24 June 2013.

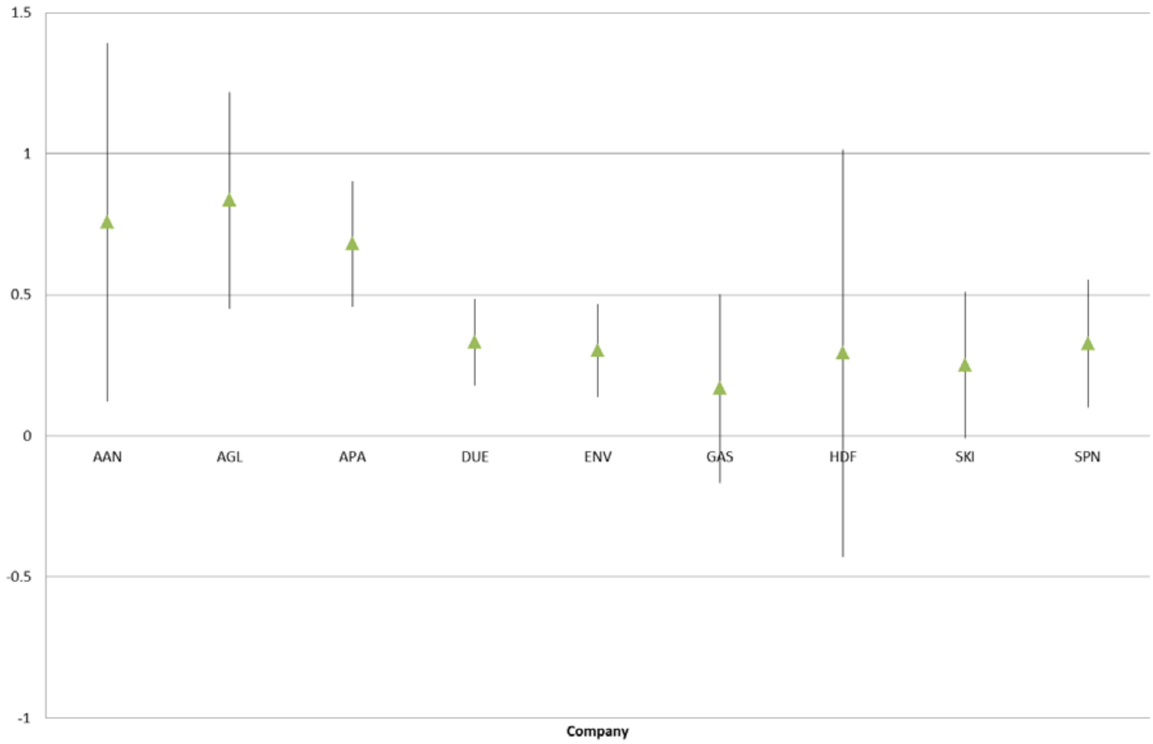
763 SFG, *Beta and the Black Capital Asset Pricing Model*, February 2015 at [31].

764 SFG, *Beta and the Black Capital Asset Pricing Model*, February 2015 at [31], Frontier Economics, *Estimating the equity beta for the benchmark efficient entity*, January 2016, p. 12-15.

765 Olan T Henry, *Estimating β: An update*, April 2014, p. 62.

766 SFG, *Regression-based estimates of risk parameters for the benchmark firm*, 24 June 2013, p. 9; Brooks, Diamond, and Hall, *Assessing the reliability of regression-based estimates of risk*, 17 June 2013.

Figure 10.6 Confidence intervals around Henry (2014) estimates (OLS estimates based on monthly sampling over the longest available time period)



Source: Olan T Henry, *Estimating β: An update*, April 2014

We note that there is no expert evidence recommending or supporting the use of such a limited sample. Professor Henry does not recommend use of the limited sample, but rather was instructed by the AER to use it.[767] The only expert evidence on this point is that of SFG and Frontier Economics recommending a broader sample.[768]

We have previously urged the AER to adopt a broader sample for estimating equity beta, based on expert advice from SFG. In our regulatory proposal, we adopted an equity beta estimate based on a sample including both Australian and US energy network businesses. In compiling this broader sample, due consideration had been given by CEG[769] (who constructed the international sample used by SFG) and SFG to the comparability of international businesses. SFG concluded that the businesses included in its sample are sufficiently comparable to the BEE such that they can be appropriately used as part of the dataset to estimate the equity beta range.[770] Further analysis by Frontier Economics, in a report accompanying this proposal, shows that the Australian and US samples are sufficiently similar that they can be grouped together for the purposes of statistical analysis.[771] Frontier Economics also shows that, due to the larger size of the US sample and greater stability in its

767 Olan T Henry, *Estimating β: An update*, April 2014, p. 4.

768 SFG, *Regression-based estimates of risk parameters for the benchmark firm*, 24 June 2013; SFG, *Beta and the Black Capital Asset Pricing Model*, February 2015; Frontier Economics, *Estimating the equity beta for the benchmark efficient entity*, January 2016, p. 17-18.

769 CEG, *Information on equity beta from US companies*, June 2013.

770 SFG, *Regression-based estimates of risk parameters for the benchmark firm*, 24 June 2013, p. 10.

771 Frontier Economics, *Estimating the equity beta for the benchmark efficient entity*, January 2016, p. 30.

composition, there is greater congruency between mean and portfolio estimates from this sample, as well as lower standard errors and tighter confidence intervals.[772]

An alternative (or additional) way to expand the data sample would be to include other comparable Australian businesses outside the energy network sector. The sample could be expanded to include businesses operating in other sectors that face a similar degree of risk to energy network businesses, such as telecommunications and transport businesses.

Expanding the sample to include businesses outside the energy sector would be consistent with our interpretation of the ARORO, as set out above. Inclusion of businesses from the telecommunications and transport sectors would ensure that the equity beta reflects the degree of risk faced by entities operating in a workably competitive market providing services similar to electricity distribution services within Australia.

Such an approach would also be consistent with a narrower definition of the BEE, such as that adopted by the AER. Even if the relevant level of risk is that of a regulated energy network business subject to economic regulation under the Law, it remains necessary to look beyond just those businesses that supply regulated energy network services within Australia in order to produce a sufficiently large datasets for robust estimation of the equity beta. Thus, it is necessary to expand the data sample to include businesses in other sectors that face a similar degree of risk to that faced by energy network businesses subject to economic regulation under the Law.

In the accompanying expert report from Frontier Economics, analysis in conducted on a broader sample of listed Australian infrastructure businesses. The businesses included by Frontier Economics include listed transport and logistics businesses (e.g. Aurizon, Asciano and Sydney Airport) and telecommunications businesses (e.g. Telstra). Frontier Economics' statistical tests confirm that these listed infrastructure businesses are sufficiently comparable to the AER's sample of energy network businesses, such that it is appropriate to group this broader set of Australian infrastructure firms together.[773]

Frontier Economics notes that expanding the sample to include other listed Australian infrastructure businesses improves the statistical properties of the resulting equity beta estimates – the estimates based on the broader domestic sample are more stable and more precise.[774] However, Frontier Economics conclude that the expanded set of domestic firms should not be relied upon alone, given the ready availability of international comparators. It is Frontier Economic's recommendation that the equity beta estimate be based on a broader dataset that includes both relevant domestic comparators and international businesses.[775]

It is common practice for regulators to use samples that include businesses outside of the sector and/or country that the regulated business operates in, in recognition of the fact that samples confined to that business' sector and/or country may be too small. For example:

- in estimating the equity beta for Telstra, the Australian Competition & Consumer Commission (**ACCC**) uses a sample of 22 international telecommunications businesses, including US, European and Asian businesses;[776]
- in estimating the equity beta for rail operator Aurizon Network, the Queensland Competition Authority (**QCA**) relies on analysis of a sample of 70 energy and water businesses, including a large number of international businesses;[777] and

[772] Frontier Economics, *Estimating the equity beta for the benchmark efficient entity*, January 2016, p. 31.

[773] Frontier Economics, *Estimating the equity beta for the benchmark efficient entity*, January 2016, p. 3-24.

[774] Frontier Economics, *Estimating the equity beta for the benchmark efficient entity*, January 2016, p 34.

[775] Frontier Economics, *Estimating the equity beta for the benchmark efficient entity*, January 2016, p 34.

[776] ACCC, *Public inquiry into final access determinations for fixed line services: Final Decision*, October 2015, pp. 80 - 83.

- in estimating the equity beta for electricity distribution businesses the Commerce Commission in New Zealand relies on a sample of firm that includes a number of international utilities.[778]

In this case, given the paucity of data for Australian energy network businesses, the sample must be expanded to include US energy network businesses and/or other Australian infrastructure businesses. Without the inclusion of these additional comparators, estimates of the equity beta for the BEE will be statistically unreliable.

The AER has erred in its determination of the equity beta range

The AER considers that 'the equity beta estimates presented in Professor Henry's empirical analysis support a range of 0.4 to 0.7' and that other empirical studies show 'an extensive pattern of support' for an equity beta within a range of 0.4 to 0.7.[779]

However Professor Henry, in his report for the AER, does not recommend a range for the equity beta of 0.4 to 0.7. Rather, Professor Henry concludes, based on his analysis of Australian energy network data only, that the point estimate for beta is likely to lie in the range of 0.3 to 0.8.[780]

The AER's conclusion is based on the fixed weight portfolio estimates and the average of individual firm estimates in Professor Henry's report.[781] However relying on these measures alone is likely to be misleading as to the precision of Professor Henry's estimates, including because:

- first, the AER's conclusion from the individual firm estimates is based on a simple average of the estimates for each firm, with the AER's range from this measure (0.46 – 0.56) simply reflecting the dispersion of average measures based on different time periods.[782] Thus, what the AER relies on is not an empirical estimate, but rather an average of estimates for individual firms. These individual firm estimates vary widely, from 0.2 to 1.0[783], and thus a simple average is largely meaningless; and
- secondly, the AER places significant weight on Professor Henry's portfolio estimates. However Professor Henry was not asked to provide expert advice on the rationale for preparing the portfolios, and it is not clear what the basis for formation of these portfolios was.[784]

Professor Henry's report in fact produces a very wide range of estimates for the equity beta, with some individual firm estimates in the range of 0.8 – 1.0 and confidence intervals around these estimates even wider, from -0.4 to 1.4 (at the 95 pe cent confidence level). As noted by SFG, the estimates vary widely depending on the chosen estimation method, sampling frequency and time period.[785]

Further, as explained above, the sample used by Professor Henry to estimate equity beta is too small to provide reliable estimates. As a result, a reliable equity beta range cannot be derived from this sample alone.

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777 QCA, *Draft Decision: Aurizon Network 2014 Draft Access Undertaking – Maximum Allowable Revenue*, September 2014, pp. 248 - 249; Incenta, *Review of Regulatory Capital Structure and Asset / Equity Beta for Aurizon Network: Report to the Queensland Competition Authority*, 9 December 2013.

778 See, for example, Commerce Commission, *Input Methodologies (Electricity Distribution and Gas Pipeline Services): Reasons Paper*, December 2010, section 6.5 and Appendix H8.

779 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-475 and 3-481.

780 Henry, *Estimating β: An update*, April 2014, p. 63.

781 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-475.

782 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-475.

783 Henry, *Estimating β: An update*, April 2014, Tables 2 and 5.

784 Henry, *Estimating β: An update*, April 2014, p. 36.

785 SFG, *Beta and the Black Capital Asset Pricing Model*, February 2015 at [31].

Evidence from wider samples supports an equity beta higher than 0.7. The evidence from Frontier Economics, SFG and CEG, based on a larger sample including international businesses indicates an equity beta of at least 0.82.

The AER's view as to the 'best empirical estimate' is not supported by evidence

There does not appear to be any evidence for the AER's statement that *'*the best empirical estimate*'* of the equity beta is 0.5.

Professor Henry does not recommend that a value of 0.5 be adopted, nor does his report refer to 0.5 as the *'*best empirical estimate*'*. Rather, as noted above, Professor Henry recommends a range of 0.3 to 0.8, based on his analysis of Australian data only.[786]

Indeed, no expert concluded that the best empirical estimate of the equity beta is 0.5. Rather, the expert evidence supported an equity beta of at least 0.8.[787]

As noted above, the AER's conclusion as to the range and 'best empirical estimate' for beta are based on its analysis of the fixed weight portfolio estimates and the average of individual firm estimates in Professor Henry's report.[788] However, for reasons set out above, the analysis underpinning these conclusions is unsound.

The only experts that have been asked to opine as to the best estimate of the equity beta are SFG and Frontier Economics. SFG's and Frontier Economics' advice is that in order to arrive at a reliable estimate of the equity beta, a sample broader than that given to Professor Henry must be used. SFG and Frontier Economics recommend an equity beta estimate of 0.82 based on a broader sample including both Australian and international businesses.[789]

The AER's adjustment to the 'best empirical estimate' is arbitrary

The AER states that the theory of the Black CAPM points to an estimate of the SL-CAPM beta that is above the best estimate indicated by Professor Henry's analysis. This appears to be the reason for the AER's adjustment from the *'*best empirical estimate*'* of 0.5 to a final point estimate of 0.7.

We understand that what the AER is seeking to make is an adjustment to the equity beta to account for is the SL-CAPM bias that is indicated by Black CAPM theory. That is, while Black CAPM theory does not say anything about adjusting the equity beta to account for SL-CAPM bias, this parameter is being used by the AER as the adjustment tool to account for this bias.

However in this case the adjustment made to the AER's *'*best empirical estimate*'* of beta is highly arbitrary. The AER cannot reasonably be satisfied that adjusting the equity beta estimate from 0.5 to 0.7 will adequately account for bias in the SL-CAPM, because it has not sought to quantify the effect of this bias.

We agree that, if the SL-CAPM is to be used alone to estimate the return on equity, some adjustment needs to be made to its input parameters to account for the known weaknesses of the model. If the SL-CAPM is used without any adjustment, the empirical evidence shows that the return on equity for low-beta stocks will be significantly under-estimated.

Our concern is that the AER's adjustment to the equity beta is not sufficient to account for the shortcomings in the AER's implementation of the SL-CAPM. In particular, it is clear that choosing the top of the AER's equity beta

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786 Henry, *Estimating β: An update*, April 2014, p. 63.

787 SFG, *Beta and the Black Capital Asset Pricing Model*, February 2015, section 4.

788 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-475.

789 Frontier Economics, *Estimating the equity beta for the benchmark efficient entity*, January 2016, p 34.

range is not sufficient to address the SL-CAPM's low-beta bias, nor does it address the statistical reliability issues associated with the small sample used by the AER to estimate the equity beta. As shown above under the heading 'The AER has erred in finding that its implementation of the SL-CAPM will produce unbiased estimates', it is clear that choosing the top of the AER's equity beta range will not correct for the low-beta bias in the SL-CAPM indicated by Black CAPM theory – if the AER's parameter estimates are used in the Black CAPM along with the best available estimate of the zero-beta premium, the return on equity estimated by the Black CAPM is above the return on equity estimated by the AER using the SL-CAPM (see the table above).

Indeed the AER acknowledges that it does not know by how much it needs to adjust its equity beta estimate to account for the issues indicated by Black CAPM theory – i.e. the effects of low-beta bias in the SL-CAPM. The AER notes that *'while the direction of this effect may be known, the magnitude is much more difficult to ascertain'*.[790] Since the AER does not estimate the Black CAPM, it cannot make a proper adjustment.

The size of the AER's adjustment is ultimately driven by the width of its equity beta range, rather than by an empirical analysis of the adjustment required to address the SL-CAPM's weaknesses. Since the AER caps its range at 0.7, the adjustment to the equity beta can take the point estimate no higher than 0.7. Of course, if the AER had adopted the recommendation of its consultant for an equity beta range of 0.3 to 0.8, its adjustment to account for Black CAPM theory and international evidence would have taken the point estimate to 0.8. Thus, the problem of arbitrariness in the AER's adjustment is compounded by the error in its construction of the equity beta range.

In this revised regulatory proposal, we put forward an alternative method for estimating the return on equity using the SL-CAPM alone, with an empirically based adjustment to account for the known weaknesses of this model. This alternative method is explained under the heading 'An alternative implementation of the foundation model approach' below and the accompanying expert report from Frontier Economics.

Reasonableness of the overall outcome

<u>The AER's cross-check analysis</u>

The AER considers that its return on equity estimate is broadly supported by:

- estimates using the Wright approach;
- estimates of the return on equity and ERP from independent valuation reports;
- the ERP range from the recent Grant Samuel valuation report for Envestra;
- estimates of the return on equity and ERP from recent broker reports; and
- estimates from other regulators.

In fact, when properly interpreted, these cross-checks do not support the AER's return equity estimate. These cross-checks actually demonstrate that the AER's estimate of the return on equity is below that required to promote efficient investment in, and efficient use of electricity services for the long-term interests of consumers.

Use of the Wright approach to support the AER's ERP estimate

As noted above, we consider that the AER has misinterpreted and misapplied the work of Professor Wright. Wright did not develop an alternative implementation of the SL-CAPM for checking of the overall return on equity. Rather, Wright developed an alternative method for estimating the MRP.

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790 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-493.

Further, the way in which the AER has developed its ERP range from the Wright approach means that this 'cross-check' will almost certainly support the AER's ERP estimate. The AER derives a wide range of estimates from the Wright approach by using an equity beta range of 0.4 to 0.7 and a market return range of 10.0 per cent to 12.7 percent.[791] The AER then checks the reasonableness of its ERP estimate by confirming that it falls within the broad range of estimates derived from the Wright approach.

Clearly if the AER had used its chosen point estimate of beta in applying the Wright approach, this cross-check would not support the AER's return on equity and ERP estimates (see the table below). Even if the AER's lower bound value for the market return from the Wright approach were to be adopted, the resulting return on equity would be above that allowed by the AER (7.8 per cent, compared to 7.3 per cent allowed by the AER). If a midpoint or upper bound value for the market return were to be taken from the Wright approach, the resulting return on equity and ERP would be significantly higher than that allowed by the AER.

Table 10.9 Estimates of the return on equity and ERP using the Wright approach[792]

Approach to estimating the ERP	ERP estimate	Return on equity estimate
AER approach (equity beta 0.7; MRP 6.5%)	4.55%	7.3%
Wright approach with lower bound Re estimate (equity beta 0.7; Rm 10.0%)	5.07%	7.8%
Wright approach with midpoint Re estimate (equity beta 0.7; Rm 11.35%)	6.01%	8.8%
Wright approach with upper bound Re estimate (equity beta 0.7; Rm 12.7%)	6.96%	9.7%

Source: CitiPower

Independent valuation reports

The AER refers to estimates of the return on equity and ERP from independent valuation reports.

We agree that evidence from independent valuation reports provides an important reasonableness check on the AER's estimate of the required return on equity. These reports provide market evidence of the return on equity required by investors.

However, for reasons set out below, we consider that this important market evidence has been misinterpreted by the AER. When properly interpreted, this evidence demonstrates that the AER's estimate of the return on equity is below that required by the market to promote efficient investment.

Most obviously, the independent valuation reports surveyed by the AER do not support the reasonableness of the AER's overall return on equity estimate. As noted by the AER, the range of imputation-adjusted estimates of the return on equity set out in these reports is 8.98 to 14.67 per cent.[793] This compares to the AER's estimate of 7.3 per cent.

This evidence also does not support the AER's ERP estimate, contrary to the conclusion of the AER in its preliminary determination. The AER states that its range of imputation-adjusted estimates for the ERP (a range of

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[791] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-507.

[792] Estimates of the market return are the AER's estimates, as set out at AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-507 to 3-508. All calculations are based on a risk-free rate of 2.76 per cent.

[793] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-514.

3.72 to 11.67 per cent) is based on the 18 independent valuation reports identified in table 3-20 of the TransGrid draft decision.[794] However after reviewing table 3-20 of the TransGrid draft decision, it is unclear to us how the AER has arrived at its ERP range.

An abridged version of table 3-20 from the TransGrid draft decision is set out in the following table. What this shows is that:

- the imputation-adjusted ERP in all but two of the surveyed reports is at least 5 per cent - well above the ERP determined by the AER (4.55 per cent);
- the imputation-adjusted ERP from the Grant Samuel report for Envestra (discussed below) is quoted as 4.47 per cent. However this appears to be based on the midpoint of Grant Samuel's range of SL-CAPM values, with none of the uplift used by Grant Samuel. As discussed below, a fundamental aspect of Grant Samuel's analysis was to conclude that the calculated SL-CAPM return on equity was not an appropriate benchmark and understated the required rate of return on equity, and this was one reason why Grant Samuel applied an uplift to its SL-CAPM-based estimates. Incenta notes that on a correct interpretation of this report, the relevant range for the ERP is 5.27 per cent to 5.37 per cent, exclusive of any uplift for the value of imputation credits.[795] This clearly does not support the AER's ERP estimate; and
- the only other report with an imputation-adjusted ERP less than 5 per cent is more than ten years old (the 2003 Deloitte report for United Energy). The return on equity and ERP estimate in this report cannot be said to be indicative of current practitioner views as to the required return on equity or ERP.

Of the 20 independent valuation reports referred to by the AER which have been published in the last decade, none of these actually used an ERP estimate below 5 per cent (adjusted for imputation). Excluding the 2003 Deloitte report and using the correct range of estimates from the Grant Samuel Envestra report, the ERP range from this evidence is approximately 5 – 5.8 per cent (based on the reports in table 3-20 of the TransGrid Draft Decision). Therefore, this market evidence clearly does not support the AER's ERP estimate.

Table 10.10 Independent valuation reports surveyed by the AER

Report date	Business	Valuer	Return on equity (imputation adjusted)[796]	ERP (imputation adjusted)
20/02/1998	Allgas Energy	Ernst & Young	n/a	n/a
19/03/1999	United Energy	SG Hambros	n/a	n/a
5/04/2003	GasNet	Sumner Hall	n/a	n/a
27/05/2003	United Energy	Deloitte	9.3	4.04
26/04/2006	AGL	Grant Samuel	11.6	5.8
19/06/2006	GasNet (regulated)	Lonergan Edwards	11.14	5.29
19/06/2006	GasNet (unregulated)	Lonergan Edwards	11.14	5.29

794 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-513, footnote 1977.

795 Incenta, *Further update on the required return on equity from independent expert reports*, February 2015, p. 25.

796 Imputation adjusted estimates are taken from Table 3-20 of the TransGrid draft decision and thus reflect the adjustments for imputation made by the AER.

Report date	Business	Valuer	Return on equity (imputation adjusted)[796]	ERP (imputation adjusted)
25/08/2006	Alinta Ltd	Grant Samuel	11.6	5.8
15/11/2006	Alinta Infrastructure Holdings	Grant Samuel	11.39	5.79
29/06/2007	Alinta Ltd (gas transmission)	Grant Samuel	11.74	5.74
29/06/2007	Alinta Ltd (gas and electricity distribution)	Grant Samuel	11.74	5.74
5/11/2007	SP AusNet (gas transmission)	Grant Samuel	11.78	5.68
5/11/2007	SP AusNet (gas and electricity distribution)	Grant Samuel	11.78	5.68
9/10/2009	Babcock & Brown Infrastructure Group (WA Gas Networks)	Grant Samuel	n/a	n/a
9/10/2009	Babcock & Brown Infrastructure Group (Tas Gas Pipeline)	Grant Samuel	n/a	n/a
9/10/2009	Babcock & Brown Infrastructure Group (WestNet Energy)	Grant Samuel	n/a	n/a
9/10/2009	Babcock & Brown Infrastructure Group (TasGas)	Grant Samuel	n/a	n/a
22/09/2010	Spark Infrastructure Group	Lonergan Edwards	n/a	n/a
24/09/2010	Prime Infrastructure Group (TasGas)	Grant Samuel	10	5
13/04/2011	Spark Infrastructure Group	Lonergan Edwards	10.9	5.4
3/08/2012	Hastings Diversified Utilities Fund	Grant Samuel	8.52	5.52
3/10/2012	DUET Group	Grant Samuel	8.54	5.54
31/05/2013	DUET Group	Grant Samuel	n/a	n/a
4/03/2014	Envestra	Grant Samuel	8.67	4.47

Source: AER, *Draft Decision, TransGrid transmission determination 2015–16 to 2017–18*, November 2014, pp.3-93 to 3-94 (Table 3-20).

Use of the Grant Samuel analysis

The AER has made significant errors in its interpretation of the Grant Samuel report for Envestra. When these errors are accounted for, it is clear that this evidence does not support the ERP and return on equity estimate adopted by the AER.

The AER presents a wide ERP range from the Grant Samuel report for Envestra – a range of 4.3 to 6.2 per cent – and on this basis concludes that its ERP estimate of 4.55 per cent is consistent with the range adopted by Grant Samuel.[797] However this range of ERP estimates referred to by the AER encompasses:[798]

- a lower bound that does not include any adjustment for imputation and does not allocate any of Grant Samuel's uplift to the ERP; and
- an upper bound that does include an adjustment for imputation and allocates all of Grant Samuel's uplift to the ERP.

The AER mixes apples and oranges, by mixing imputation-adjusted estimates with unadjusted estimates from the Grant Samuel report. Such an approach is illogical, particularly in circumstances where Grant Samuel has made clear that its estimates make no allowance for imputation credits.[799] Given that no allowance is made in the Grant Samuel estimates for imputation, an imputation adjustment must be made for comparison with the AER's ERP estimate. The unadjusted estimates from the Grant Samuel report are simply not comparable with the AER's ERP estimates. This is made clear in Grant Samuel's letter in response to the NSW draft decisions, where it states:[800]

> *It is abundantly clear in our reports that we make no adjustment in our valuations for dividend imputation. Accordingly, a dividend imputation adjustment would be required to ensure comparability with the AER basis of calculation.*

Further, the Grant Samuel report and its letter in response to the NSW draft decisions make clear that the uplift is to account for factors likely to be affecting the return on equity (not the return on debt). The factors taken into account by Grant Samuel in making the uplift include: repricing of risk by equity investors since the GFC; alternative models, such as the Gordon Growth Model (a version of the DGM), currently indicating higher returns on equity than the SL-CAPM; and evidence that brokers are currently adopting cost of equity estimates that are higher than indicated by the SL-CAPM.[801]

A fundamental aspect of Grant Samuel's analysis was to conclude that the calculated SL-CAPM return on equity was not an appropriate benchmark and understated the realistic required rate of return on equity, and this was one reason why Grant Samuel applied an uplift to its SL-CAPM estimates. Therefore it is not appropriate to use Grant Samuel's 'lower bound' SL-CAPM estimate of the return on equity with no uplift.

Finally, it should be noted from the Grant Samuel report that it adopted a WACC estimate at the lower end of its range (6.5 per cent - 7.0 per cent) for the purposes of its valuation of Envestra assets, in order to ensure that the fairness assessment for the APA proposal was robust.[802] That is, Grant Samuel erred towards the lower end of its WACC range to ensure that its NPV valuation of the Envestra assets was conservative on the high side. This same tendency is not required to satisfy and, we argue, not consistent with the NEO or the ARORO, because these objectives seek to determine the return on equity that is sufficient to attract efficient investment in our network.

On a correct interpretation of the Grant Samuel report for Envestra, it is clear that it does not support the AER's return on equity or ERP estimate. Incenta notes that the range for the return on equity implied by Grant Samuel's

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797 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-516.

798 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-516 (footnote 1984).

799 Samuel, *Financial Services Guide and Independent Expert's Report to the Independent Board Sub-committee in relation to the Proposal by APA Group*, 3 March 2014, Appendix 3, pp. 8 - 9.

800 Samuel, *Grant Samuel response to AER draft decision*, 12 January 2015, p. 7.

801 Samuel, *Financial Services Guide and Independent Expert's Report to the Independent Board Sub-committee in relation to the Proposal by APA Group*, 3 March 2014, Appendix 3, pp. 8 - 9.

802 Samuel, *Grant Samuel response to AER draft decision*, 12 January 2015, p. 4.

uplift factor was from 9.47 per cent to 9.57 per cent, with a respective ERP range of 5.27 per cent to 5.37 per cent, exclusive of any uplift for the value of imputation credits.[803] These Grant Samuel ranges compare with the AER's cost of equity of 7.3 per cent and ERP of 4.55 per cent.

Broker reports

The information from broker reports referred to in the AER's preliminary determination does not support the AER's return on equity estimate.

It should be noted that the AER only refers to estimates from recent broker reports, being reports published over the past year. These reports therefore provide good information as to current market expectations of the required return on equity. These reports also provide some indication of how market practitioners have been estimating the return on equity in the current low risk-free rate environment.

Given that these reports are current, it is not appropriate to focus just on the ERP in these reports, as the AER appears to have done.[804] The evidence from these reports should also be used as a cross-check on the overall rate of return.

The relevant estimates for both the return on equity and ERP are the imputation-adjusted estimates. Estimates without an imputation adjustment cannot be compared to the AER's estimates of the ERP and return on equity.

The AER reports a range for the imputation-adjusted return on equity in recent broker reports of 7.3 to 9.3 per cent.[805] The AER's estimate of the return on equity is at the very bottom of this range.

ERP estimates from 'other market participants', including practitioners and regulators

The AER also refers to ERP and return on equity estimates from other regulators, as part of the other information it takes into account in step 5 of its foundation model approach.

We consider that past decisions of the AER and other regulators should not be used as direct evidence of the required return on equity. These decisions are, at best, secondary evidence of the prevailing return on equity at previous points in time. However the return on equity in these decisions:

- will not reflect prevailing market conditions (rather, they will reflect market conditions at the time the decision was made); and
- may not be consistent with the ARORO, to the extent that they have been determined under different regulatory frameworks with different objectives.

Use of such decisions will also be circular and self-perpetuating where it is based on previous decisions the same regulator has made in relation to the return on equity.

For these reasons, we do not propose a role for other regulators' decisions in determining the return on equity for the BEE.

Conditioning variables

The AER's preliminary determination refers to a number of conditioning variables, which are said to provide directional information, particularly in relation to the MRP. The evidence from these conditioning variables does not support the AER's approach to estimating the return on equity. In particular, this evidence is inconsistent

803 Incenta, *Further update on the required return on equity from independent expert reports*, February 2015, p. 25.

804 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-517.

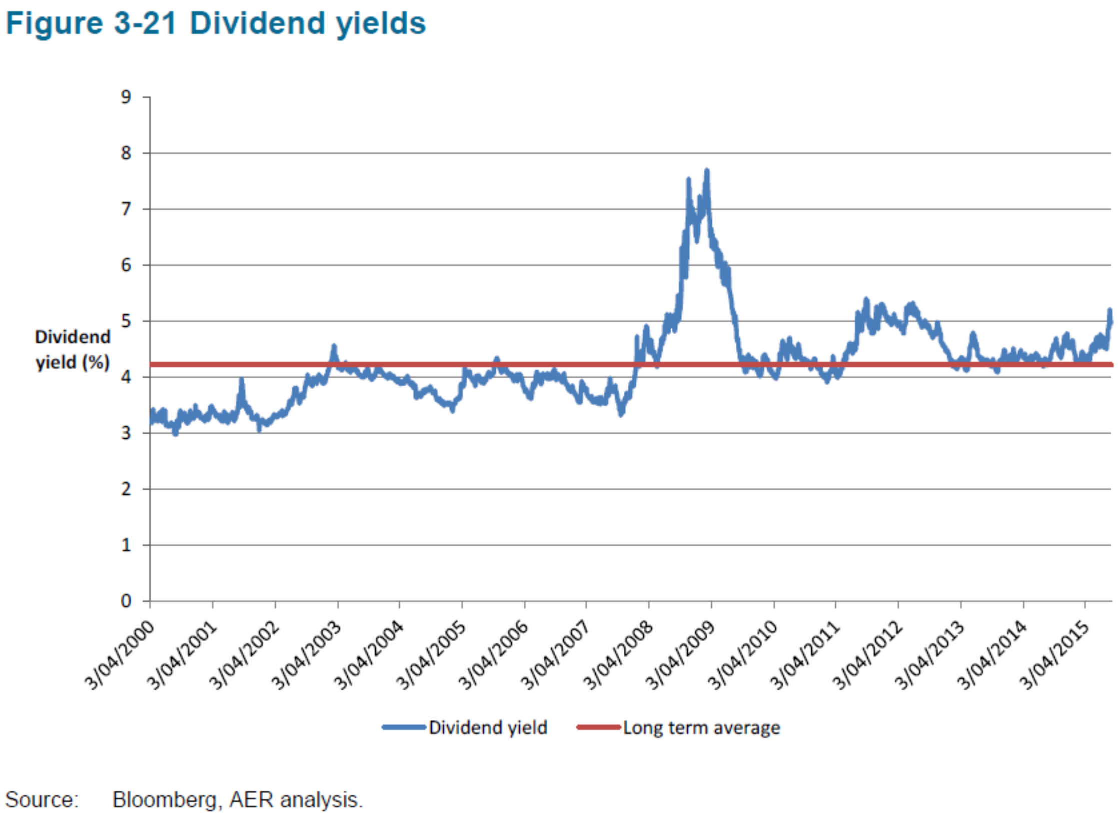
805 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-517.

with the AER's assumption that as the risk-free rate has fallen the MRP has remained constant (meaning that the return on equity has fallen in lock-step with the risk-free rate).

Dividend yields

As shown by the AER's figure 3-21 (reproduced, for convenience, below), dividend yields have increased significantly in recent months and are now well above pre-GFC levels.[806]

Figure 10.7 Dividend yields



Source: AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015

As explained by CEG, given that the risk-free rate has been lower in the post-GFC period (and is now near historic lows), this implies that the MRP has risen by more than an offsetting amount.[807] Certainly, this evidence is not consistent with the AER's view that the return on equity has been falling in lock-step with the risk-free rate.

The AER has misinterpreted this evidence, by treating it as merely an indicator of whether the MRP is above or below historical average levels. The AER dismisses this evidence on the basis that:[808]

> *It is unclear whether the recent increase in dividend yields is evidence of a sharp and sustained move away from their long term average. This short term movement does not provide a clear signal that the MRP should not be close to its historical average level.*

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[806] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-391.

[807] CEG, *Estimating the cost of equity, equity beta and MRP*, January 2015, p. 27.

[808] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-390.

However, movements in the dividend yield are not just an indicator of changes in the risk premium required by investors. Rather, changes in dividend yield indicate movements in the overall required return on equity. Therefore, the fact that dividend yields have been increasing and are now well above pre-GFC levels indicates that as the risk-free rate has fallen post-GFC, the ERP has increased.

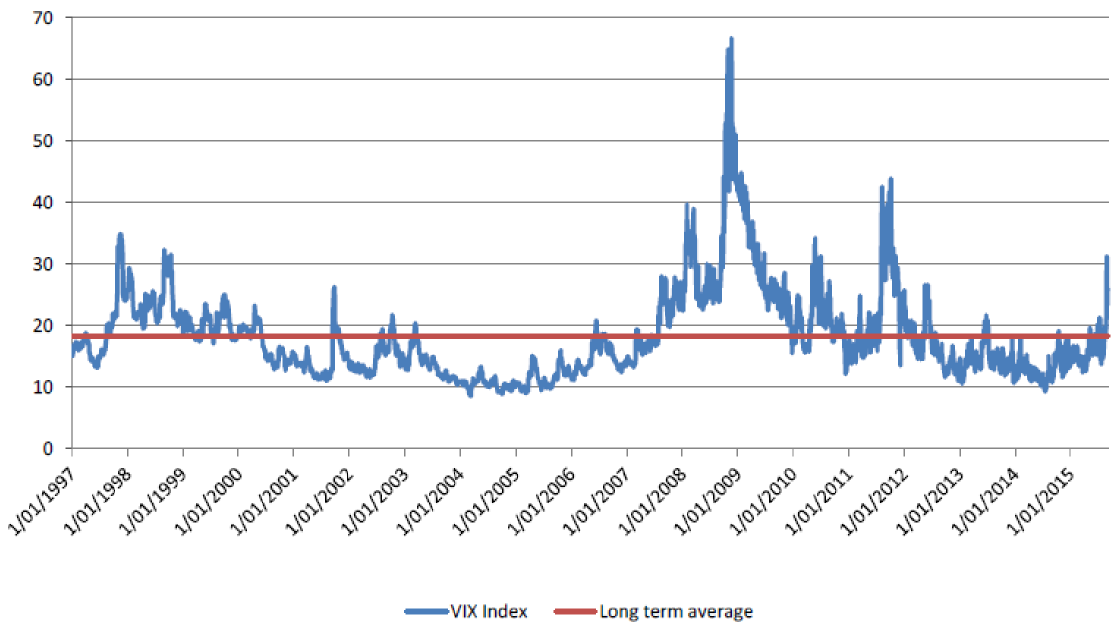
This evidence certainly does not support the AER's assumption that the return on equity has been falling in lock-step with the risk-free rate.

Implied volatility

As shown by the AER's figure 3-21 (reproduced, for convenience, below), the ASX200 implied volatility index has increased significantly in recent months and is now well above its 20-year average.[809]

Figure 10.8 Implied volatility (VIX) over time

Figure 3-24 Implied volatility (VIX) over time



Source: ASX200 VIX volatility index, sourced via Bloomberg cost AS51VIX from 2/1/2008 and CITJAVIX prior to 2/1/2008.

Source: AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015

Whereas in previous decisions the AER has considered a relatively stable volatility index to be evidence of a steady MRP, in the AER's preliminary determination, it does not appear to take the recent increase in this measure into account as evidence of a higher MRP.

Rather, like the evidence of higher dividend yields, the AER seeks to dismiss this evidence on the basis that it 'does not provide a clear signal'. The AER states:[810]

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809 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-394.

In the month of August, implied volatility has increased relative to its steady pattern of being below its long run average since 2012. This short term movement does not provide a clear signal that the MRP should not be close to its historical average level.

We consider that the evidence for a higher MRP could not be any clearer. The AER's DGM analysis indicates that the MRP has increased as the risk-free rate has fallen, and that the MRP is now well above its historical average. The evidence from dividend yields and implied volatility measures further support this.

On the other hand, there does not appear to be any clear evidence to support the AER's view that the MRP has not changed as the risk-free rate has fallen or that the return on equity has fallen in lock-step with the risk-free rate—or even that current market conditions are consistent with average market conditions.

An alternative implementation of the foundation model approach

Our preferred approach to estimating the return on equity is as set out in our regulatory proposal. This approach has regard to all relevant models and evidence, and uses this material for its proper purpose. Each of the relevant return on equity models is independently used to derive an estimate of the required return on equity, while other relevant evidence is used to determine the best estimate of each parameter within these models. The outputs from each relevant model are then weighted to arrive at a return on equity estimate. Based on updated data to reflect prevailing market conditions, this approach leads to an estimate of the prevailing return on equity of 9.8 per cent.

However, if the AER proposes to continue relying solely on the SL-CAPM to estimate the return on equity, the AER must change the way it implements this model. It is clear from the evidence referred to above that the way in which the SL-CAPM is applied in the AER's preliminary determination leads to a return on equity that is not consistent with the ARORO and does not reflect prevailing market conditions. The AER does not properly recognise the weaknesses of the SL-CAPM, nor does it account for these weaknesses in its application of the model. Further, the AER's practice of applying an effectively fixed ERP to a variable risk-free rate is not appropriate in current market conditions, since it leads to the return on equity moving in lock-step with changes in the risk-free rate. The result is that the AER's estimate of the return on equity is below the level of return required by the market, as indicated by the AER's cross-checks and other relevant evidence.

The accompanying expert report of Frontier Economics outlines an alternative approach that involves properly adjusting SL-CAPM parameters to deliver a return on equity that contributes to the achievement of the ARORO and reflects prevailing market conditions. This involves:[811]

- using a current measure of the risk-free rate (i.e. the prevailing yield on 10-year CGS). Over the 20 business days to 30 September 2015, this produces a risk-free rate of 2.75 per cent;
- deriving the MRP in a way that gives appropriate weight to measures of the prevailing (current) MRP. Frontier recommends that 50 per cent weight be given to estimates of the prevailing MRP from the DGM, 40 per cent weight to historical measures and 10 per cent weight to evidence from independent expert reports (i.e. evidence of market practitioner estimates of the MRP). Of the 40 per cent weight that is assigned to historical measures equal weight (i.e. 20 per cent each) is given to estimates of historical excess returns and estimates using the Wright approach. Over the 20 business days to 30 September 2015, this produces an MRP of 7.9 per cent;
- estimating a 'starting point' equity beta using a sufficiently large dataset. Frontier Economics recommends including both US and Australian energy network businesses to ensure that the dataset is large enough to

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[810] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-394.

[811] Frontier Economics, *The required return on equity for the benchmark efficient entity*, January 2016.

produce robust estimates, with twice as much weight given to the Australian data. This produces a 'starting point' equity beta of 0.82; and

- making two transparent and empirically based adjustments to the starting point equity beta estimate to account for the known shortcomings of the SL-CAPM:
  - the first of these adjustments is to account for low beta bias, and draws on empirical evidence from the Black CAPM. Frontier Economics recommends that 75 per cent weight be given to this adjustment, in recognition of the strong and consistent evidence of low-beta bias in the empirical literature (i.e. the adjustment is 75 per cent of the full adjustment that would need to be made to account for low-beta bias). This results in an adjustment from the starting point beta of 0.82 to a beta of 0.88; and
  - the second adjustment is to account for book-to-market bias (i.e. the failure of the SL-CAPM to account for the effect of book-to-market ratio on stock returns). Frontier Economics recommends giving less weight to this adjustment (25 per cent weight) in recognition that the evidence in relation to this bias is more recent. This results in a further adjustment, to an equity beta of 0.91.

This leads to an estimate of prevailing return on equity of 9.9 per cent (based on the 20 business days to 30 September 2015).

Frontier Economics observes that this estimate from the 'adjusted SL-CAPM' is close to their estimate using the DGM, a model that is not affected by low-beta or book-to-market bias. Thus, the evidence from the DGM corroborates Frontier Economics' adjusted SL-CAPM estimate.

10.4.4 Our revised regulatory proposal

Our preferred approach to estimating the return on equity is as set out in our regulatory proposal. This approach has regard to all relevant models and evidence, and uses this material for its proper purpose. Each of the relevant return on equity models is independently used to derive an estimate of the required return on equity, while other relevant evidence is used to determine the best estimate of each parameter within these models. The outputs from each relevant model are then combined to arrive at a return on equity estimate. Based on updated data to reflect prevailing market conditions, this approach leads to an estimate of prevailing return on equity of 9.82 per cent.

However if the AER proposes to continue relying solely on the SL-CAPM to estimate the return on equity, the AER must change the way it implements this model. The way in which the SL-CAPM is applied in the AER's preliminary determination leads to a return on equity that is not consistent with the ARORO and does not reflect prevailing market conditions. The AER does not properly recognise the weaknesses of the SL-CAPM, nor does it account for these weaknesses in its application of the model. Further, the AER's practice of applying an effectively fixed risk premium to a variable risk-free rate is not appropriate in current market conditions, since it leads to the return on equity moving inappropriately in lock-step with changes in the risk-free rate.

The accompanying expert report of Frontier Economics outlines an alternative approach that involves properly adjusting SL-CAPM parameters to deliver a return on equity that contributes to the achievement of the ARORO and reflects prevailing market conditions. This involves:

- making a transparent and empirically based adjustment to the equity beta estimate to account for the known shortcomings of the SL-CAPM, particularly low beta bias; and
- deriving the MRP in a way that gives appropriate weight to measures of the prevailing (current MRP).

This leads to an estimate of prevailing return on equity of 9.9 per cent (based on the 20 business days to 30 September 2015). This is calculated using the SL-CAPM with an equity beta of 0.91, MRP of 7.9 per cent and a risk-free rate of 2.75 per cent.

For reasons set out above, we consider that either the multi-model approach or the ‘adjusted SL-CAPM’ approach (as described above) would be clearly preferable to the approach taken in the AER's preliminary determination. For the purposes of this revised regulatory proposal, we adopt the ‘adjusted SL-CAPM’ approach.

Either of the alternative approaches put forward by us would represent a departure from the methods for estimating the return on equity set out in the RoR Guideline. Our reasons for departure are set out in this chapter.

In light of the temporal constraints for the preparation of our response to the AER's preliminary determination, and the uncertainty as to the timing of the Tribunal decision in the NSW and ACT merits reviews (which decision will impact on many of the issues dealt with in this chapter), we have used as a placeholder in the models submitted with this revised regulatory proposal the return on equity estimate used for the purposes of the AER's preliminary determination. While we have used this estimate for convenience, we propose that, for the purposes of making the new distribution determination in substitution for the preliminary determination, the return on equity for the 2016–2020 regulatory control period be estimated in accordance with the methodology outlined in this revised regulatory proposal by reference to our accepted equity averaging period.

To assist the AER in making a new distribution determination in substitution for its preliminary determination, after the Tribunal decision in the NSW and ACT merits reviews is published and our actual equity averaging period has passed, we intend to submit to the AER a model that sets out the return on equity estimate determined by reference to our actual equity averaging period.

10.5 Return on debt

10.5.1 Initial regulatory proposal

In our regulatory proposal, we proposed a return on debt consistent with the RoR Guideline except that we proposed:[812]

- a benchmark credit rating of BBB, rather than BBB+;
- transitional arrangements consistent with those recommended by CEG, rather than the transitional arrangements in the RoR Guideline. The proposed arrangements involved transitioning only the risk free rate component of the return on debt in the manner outlined in the RoR Guideline (and not the DRP component);
- a process for nominating the averaging periods for estimating the annual return on debt for the 2017 to 2020 regulatory years, rather than those averaging periods being specified prior to the commencement of the regulatory control period; and
- the inclusion of transaction costs associated with maintaining a swap portfolio.

We also proposed, consistent with preliminary decisions of the AER at that time, that the return on debt be estimated by giving a 50 per cent weighting to each of the Bloomberg BBB BVAL and RBA published data series, each extrapolated out to a 10 year tenor (where necessary). We proposed a goodness of fit test to select the extrapolation methodology to be applied from the methodology used by the AER in preliminary decisions leading up to our regulatory proposals and the methodology proposed by SA Power Networks.

[812] CitiPower, *Regulatory proposal 2016–2020*, April 2015, section 12.4.

10.5.2 AER's preliminary determination

The AER's preliminary determination in relation to the return on debt is to maintain the return on debt methodology proposed in the RoR Guideline.[813] That is, applied to our regulatory control period, the AER's preliminary determination on the return on debt is to:[814]

- estimate the return on debt using an on-the-day rate in the first regulatory year (2016) of the 2016–2020 regulatory control period; and
- transition this rate into a trailing average approach over 10 years by updating 10 per cent of the return on debt each year to reflect prevailing interest rates.

The AER's preliminary determination on implementing the return on debt approach involves using:

- a benchmark credit rating of BBB+;
- a benchmark term of debt of 10 years;
- a simple average of the broad BBB rated debt data series published by the RBA and Bloomberg, adjusted to reflect a 10 year estimate (using the AER's extrapolation method) and other adjustments; and
- an averaging period for each regulatory year of between 10 business days and 12 months (nominated by us in advance of the AER's final decision) prior to 25 days before submission of the annual pricing proposal or reference tariff variation proposal.[815]

10.5.3 Our response to the AER's preliminary determination

Introduction

We submit that in making a new distribution determination in substitution for the revoked preliminary determination, the AER should estimate the return on debt using the trailing average approach. We agree that the trailing average approach should be adopted to estimate the return on debt because infrastructure businesses operating in workably competitive markets would be expected to hold a staggered portfolio of fixed rate debt and the costs of holding such a portfolio are best approximated by the trailing average approach to estimating the return on debt.

However, we do not agree that the AER's proposed ten year transition to the trailing average approach should be adopted. Rather, we submit that there should be no transition to the trailing average approach. The reference to 'efficient financing costs' in clause 6.5.2(c) of the Rules can only be understood to be the costs that would be incurred in a workably competitive market—this is what efficient financing costs are. As the debt financing practice that would be expected absent regulation is to hold a staggered portfolio of fixed-rate debt, and the trailing average approach provides an estimate of the return on debt that is commensurate with this practice, the Rules require the immediate adoption of the trailing average approach.

If we are incorrect that the efficient financing costs of a BEE are to be estimated by reference to the costs that would be incurred in a workably competitive market, and the AER is correct to estimate the return on debt by reference to efficient financing costs incurred by a BEE subject to economic regulation under the Rules, we submit that the AER should adopt an optimal hedge form of hybrid transition. This approach involves:

- for the base rate component of the return on debt, adopting:

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813 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-143.

814 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-144, 3-548.

815 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-149.

  - a 10 year transition to a trailing average for the proportion of the debt portfolio assumed to have been hedged by the BEE using interest rate swaps; and
  - no transition for the proportion of the debt portfolio assumed not to have been hedged by the BEE (that is, moving immediately to the trailing average approach); and
- for the debt margin (or DRP) component, applying no transition by moving immediately to the trailing average approach from the first year of the 2016–2020 regulatory control period.

In respect of the implementation issues, we submit that in making a new distribution determination in substitution for the revoked preliminary determination, the AER should:

- adopt a benchmark credit rating of BBB to BBB+;
- continue to adopt a benchmark term of 10 years;
- for the purposes of estimating the prevailing return on debt for each year included in the trailing average prior to 2016 (i.e. 2007 to 2015), use a simple average of the BBB Bloomberg and RBA data series; and
- for the purposes of estimating the prevailing return on debt for the 2016 regulatory year and beyond, use a weighted average of the RBA, BBB BVAL and Reuters data series. We give 50% weight to the RBA and 25% weight each to BVAL and Reuters data series.

We note that the AER's proposed method for estimating the return on debt does not make any allowance for a new issue premium. We consider that in light of the evidence of a positive and significant new issue premium, making no allowance for this premium (as we do) is highly conservative, in the sense that it is likely to lead to under-estimation of the efficient financing costs of a BEE.

Our position on each of the above issues is addressed in detail below, after we make an observation regarding the cost of debt information gathered by the AER prior to the preliminary determination.

In August 2015, the AER collected information on the actual costs of debt and financing practices from private sector service providers with regulatory proposals currently before it.[816] The AER stated in its preliminary determination that, in aggregated form, this information may help to form conclusions about the financing practices historically and currently employed by the BEE.[817] The AER indicated, however, that it would consult more broadly with stakeholders on any future use of this information.[818]

We agree that the AER is required to consult in respect of any proposed use of such information (including because the AER has not provided us with an opportunity to consider the data collected from other service providers or the way in which it proposes to use the data). There are significant limitations to the data collected by the AER. First, the data collected by the AER is not that of all private sector service providers (but rather, only those service providers with regulatory proposals before it at the time it issued the information requests). Secondly, the AER requested only a snapshot of information (being debt information as at 30 June 2015).[819] The use to which such a snapshot can be put is necessarily limited.

We reserve the right to further comment on the errors into which the AER may fall if it seeks to rely on the cost of debt information collected in the course of the consultation that the AER has flagged will take place in the event it seeks to rely on this information.

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816 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-160.

817 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-160.

818 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-160.

819 RE Vic. EDPR - CitiPower - IR016 - 24 July 2015 - Email attachment (Debt information request - CitiPower)

Trailing average approach

In the RoR Guideline, the AER proposed to estimate the allowed return on debt using:

- a trailing average approach with the length of the trailing average being 10 years;
- equal weights to be applied to all the elements of the trailing average; and
- the trailing average to be automatically updated every regulatory year within the regulatory control period.[820]

We agree with the proposed approach in the RoR Guideline to estimate the return on debt using a trailing average approach. We agree with the AER that the trailing average approach is likely to contribute to the achievement of the ARORO and recognises the desirability of minimising any difference between the return on debt and the return on debt of a BEE referred to in the ARORO.[821] This includes because, as noted by the AER, the trailing average approach allows a service provider to manage both interest rate risk and refinancing risk, without the use of interest rate swaps, which are a product of the on-the-day approach.[822] As discussed below, the trailing average approach will provide an estimate of the return on debt that is commensurate with the financing costs that would be incurred by a firm operating in the manner of a firm in a competitive environment.

However, and as discussed in detail below, we do not agree with the proposed approach in the RoR Guideline, and as adopted in the AER's preliminary determination, to implement the trailing average approach after a period of transition.[823] That is, we submit that the AER should immediately apply the trailing average approach without a transition.

The AER’s decision to impose a 10 year transition to the trailing average approach

<u>The AER’s view of efficient financing costs</u>

In the AER's preliminary determination the AER adopts the conceptual definition of the BEE as set out in the RoR Guideline, namely: 'pure place, regulated energy network business operating within Australia'.[824] In relation to the 'regulated' aspect of this definition, the AER states: 'A regulated entity for the purposes of our benchmark is one which is subject to economic regulation (that is, price cap regulation) under the National Electricity Rules and/or the National Gas Rules'.[825]

The AER describes the efficient debt financing costs of a BEE in the following way:[826]

> *… those which are expected to minimise its debt financing costs over the life of its assets, while managing refinancing risk and interest rate risk:*
>
> *Refinancing risk—the risk that a benchmark efficient entity would not be able to refinance its debt when it matures.*
>
> *Interest rate risk—the risk associated with a mismatch between the allowed return on debt and a benchmark efficient entity’s actual return on debt.*

820 AER, *Better Regulation, Rate of Return Guideline*, December 2013, p. 19.

821 AER, *Better Regulation, Rate of Return Guideline*, December 2013, p. 19.

822 AER, *Better Regulation, Explanatory Statement, Rate of Return Guideline*, December 2013, p. 108.

823 AER, *Better Regulation, Rate of Return Guideline*, December 2013, p. 19.

824 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-24.

825 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-25.

826 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-166.

Having defined the BEE and the efficient debt financing costs of a BEE, the AER concludes that the efficient debt financing practices of the BEE under the previous on-the-day approach to estimating the return on debt would have involved the following:[827]

- borrowing long term (10 year) debt and staggering the borrowing so only a small proportion (around 10 per cent) of the debt matured each year;
- borrowing using floating rate debt, or borrowing fixed rate debt and converting it to floating rate debt using fixed-to-floating interest rate swaps at the time of the debt issue, which extended for the term of the debt (10 years); and
- entering floating-to-fixed interest rate swaps at, or around, the time of the service provider's averaging period, which extended for the term of the regulatory period (typically five years).

The AER concludes that, under the financing practice described above, the base rate component of the AER's BEE's actual return on debt would have broadly matched the on-the-day rate, while the DRP component each year would have reflected the average of the previous ten years.[828]

Critical to the AER's findings as to efficient financing practices (and, in turn, efficient financing costs), is that such practices involve the BEE hedging the base rate component. It is uncontroversial that the financing practice as described above would only be engaged in under the on-the-day approach. However, efficient financing costs (achieved through the adoption of efficient financing practices) under the Rules should not be identified by reference to what a regulated entity might do in response to a particular methodology adopted by a regulator to calculate the return on debt allowance. Rather, as elaborated below, efficient financing costs are properly identified by reference to financing practices that would be adopted in workably competitive markets.

<u>Efficient financing costs referred to in the ARORO</u>

As noted in the ARORO section above, the term 'efficient financing costs' in the ARORO is properly understood as referring to the costs that would be expected to be incurred in a workably competitive market.

A firm operating in the manner of a firm in a competitive environment would have a conventional debt portfolio of the type held by privately-owned entities in unregulated markets, namely a staggered portfolio of fixed rate debt.

This is confirmed by the AER's consultant, Chairmont, who states:[829]

> *The decision to adopt a strategy of gradual staggered issuance of fixed rate debt is consistent with behaviour where the regulatory cost of debt framework does not apply.*

Similarly, CEG has found that unregulated businesses typically raise debt in a staggered manner.[830]

> *In reality, almost all businesses, including regulated infrastructure businesses, raise debt in a staggered fashion over time. Moreover, for infrastructure businesses with very long lived assets, the average maturity of this debt at the time of issue tends to be long term (10 years or more). It is very likely that this is a response to*

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827 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-186.

828 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-186 to 3-187.

829 Chairmont, *Cost of Debt: Transitional Analysis*, April 2015, p. 38. At page 38, Chairmont references UBS' statement that: 'The 'trailing average' approach used by Networks NSW was consistent with debt management strategies adopted by non-regulated entities in the infrastructure sector – ports, airports, road and railways': UBS, *UBS Response to the TransGrid Request for Interest Rate Risk Analysis following the AER Draft Decision of November 2014*, undated, p. 5. See also: Frontier Economics, *Cost of Debt Transition for NSW Distribution Networks*, January 2015, pp. 8 - 9.

830 CEG, *Efficiency of Staggered Debt Issuance*, February 2013 at [92] and [97].

a desire to minimise transaction costs, in particular insolvency/bankruptcy costs, that are heightened if too much debt must be refinanced in a short period of time. Consequently, a business's cost of debt at any given time will reflect the costs incurred when issuing debt over the last decade (i.e., not just over the last 20 days).

…

A 10 year trailing average approach would largely mimic the debt management strategy employed by infrastructure businesses (regulated and unregulated) around the world.

The debt financing costs of a staggered fixed rate debt portfolio match the debt costs calculated under the AER's trailing average approach. Put another way, the efficient financing costs of a BEE (being an unregulated entity operating in a workably competitive market) are the costs produced by application of the trailing average approach. Therefore, on a correct construction of the term 'efficient financing costs' in the ARORO, there is no basis for the imposition of a transition.

Having identified in the RoR Guideline that the trailing average approach promotes the productive, allocative and dynamic efficiency of debt financing practices, and specifically provides incentives for service providers to seek the lowest debt financing costs,[831] and therefore, is consistent with the outcomes of a workably competitive market, the AER should have adopted the trailing average approach as the methodology to estimate the return on debt, without any transition.

Adoption of the AER's proposed transition would be inconsistent with the NEO and the revenue and pricing principles in providing an allowance for costs associated with financing practices adopted in response to a prior regulatory regime and would not impose an appropriate pricing signal for investment. That is, rather than sending a pricing signal that mimics the pricing signal that would be sent as a result of competition in a workably competitive market, the pricing signal sent under the AER's approach would be that arising from the idiosyncratic application of a prior regulatory methodology to estimating the return on debt.

In the AER's preliminary determination, the AER states that it is not satisfied that immediate application of the trailing average approach is reasonable or would contribute to the achievement of the ARORO.[832] The reasons given by the AER are that:

- it has the potential to create a bias in regulatory decision making that can arise from the selection of historical data after the results of that data are already known;
- it would exaggerate a mismatch between the allowed rate of return and the efficient financing costs of a BEE over the life of its assets, with the consequence that over the life of the assets, a BEE is likely to materially either over- or under-recover its efficient financing costs; and
- it does not approximately match the allowed return on debt with the efficient financing costs of a BEE over the 2016–2020 regulatory control period as it transitions its financing practices to the trailing average approach.[833]

If we are correct that the term 'efficient costs' is to be interpreted as the costs that would be incurred in a workably competitive market, immediate adoption of the trailing average approach will approximately match the allowed return on debt with the efficient financing costs of a BEE. Therefore, the last point in the list above is not a reason to delay the immediate application of the trailing average approach.

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[831] AER, *Better Regulation, Explanatory statement, Draft rate of return guideline*, August 2013, pp. 83 - 84.

[832] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-165.

[833] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-165.

In relation to the first two points in the list above, being the introduction of bias into regulatory decision making and violations of the NPV=0 principle, we submit that these policy issues are not relevant under the Law and the Rules decision-making framework, and that even if they were, they do not support the AER's transition. These points are discussed below in the context of the hybrid approach.

If we are incorrect and efficient financing practices (and, in turn, efficient financing costs under the ARORO) are to be determined by reference to what a BEE would be expected to do in response to the regulatory framework, there is no sound basis upon which a transition should be applied to the DRP or unhedged base rate components of the return on debt. These issues are discussed below.

<u>Even if the AER's view of efficient financing costs is correct, it has adopted the wrong transition</u>

As the AER acknowledges, the DRP component of the return on debt cannot be—and thus during and prior to the 2011–2015 regulatory control period could not have been—hedged.[834]

> *For the debt risk premium component, we consider the allowed and actual return of a benchmark efficient entity would have usually differed in each access arrangement period [sic]. This is because the DRP component could not have been efficiently hedged to the allowed debt risk premium. So, in some access arrangement periods [sic], the allowed debt risk premium would have exceeded the actual debt risk premium of a benchmark efficient entity. In other access arrangement periods [sic], the allowed debt risk premium would have been less than the actual debt risk premium.*

Therefore, even if hedging strategies under the previous regulatory approach were relevant, it logically follows from the fact that the DRP component could not have been hedged that no transition should be applied to the DRP component and a trailing average approach should be immediately adopted. This is the advice given by Chairmont to the AER in Chairmont's April 2015 report.

> *The DRP does not need to be transitioned because the NSP already has a staggered floating rate debt portfolio.*[835]
>
> *…*
>
> *A [benchmark efficient entity] will already have a staggered DRP in its portfolio, but not evenly distributed, i.e. not smooth. Therefore, to match this situation the AER should not transition the DRP, but instead move immediately to a 'trailing average' for this element. As there is no standard methodology to account for the non-smooth portfolio, AER should adopt a smooth 'trailing average' for the DRP. It is acknowledged that the measurement of historical DRP is difficult, because it is accurate only at the time of debt issuance; however it is likely that a reasonable estimate could be determined…*[836]

The October 2015 Chairmont report reiterated that, if the AER's identified efficient financing practice was to be adopted, consistency requires that a trailing average DRP be applied. The report stated that as a consequence of the efficient financing practice adopted by the AER -

> *The allowed return on debt should be calculated in line with the Basic Approach, i.e. a trailing average DRP*.[837]

Chairmont concludes that the AER's 'Basic Approach' to efficient financing practices, which involves entities hedging the base rate component of the return on debt and having a trailing average DRP, minimises differences between the regulated return on debt and the actual cost of debt faced by a BEE in the transition phase.[838]

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[834] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-175 to 3-176.

[835] Chairmont, *Cost of Debt: Transitional Analysis*, April 2015, pp. 8 - 9.

[836] Chairmont, *Cost of Debt: Transitional Analysis*, April 2015, p. 47.

[837] Chairmont, *Financing Practices Under Regulation: Past and Transitional*, 13 October 2015, p. 14.

> *The Basic Approach to EFP [efficient financing practices], i.e. the trailing average DRP plus the average 1-10 year swap rates, minimises any discrepancy between the allowed and actual cost of debt in the transition phase for a BEE [benchmark efficient entity], whereas the Guideline Allowance does not.*

In the AER's preliminary determination, the AER agreed with Chairmont that the hybrid approach would provide a good match over the ten year transition period to the costs of the AER's BEE.[839] However, the AER determined that it would not adopt the hybrid approach in calculating the return on debt.[840]

> *We agree with Chairmont that the hybrid approach will provide a good match over the 10 year transition period to the costs of a benchmark efficient entity entering the transition from the 'on-the-day' regime. However, having regard to wider policy issues, we have maintained the Guideline approach. In particular we consider that proposal and adoption of the hybrid approach on the basis of changes in prevailing rates would introduce bias into regulatory decision making and violate the NPV=0 principle.*

There is no scope in the Law and the Rules for regard to be had to these 'wider policy' issues as they have been formulated by the AER. Even if these matters as formulated by the AER were properly to be considered in making a decision on the return on debt, neither the purported introduction of 'bias' into regulatory decision making, nor alleged 'violations' of the NPV=0 principle, provide a logical or reasoned basis to apply a transition to the DRP component of the return on debt.

Bias

In the AER's preliminary determination, the AER states that the use of data from earlier periods—which is necessary under the trailing average approach—results in biased estimates and that use of unbiased estimates promotes the ARORO.[841]

> *We consider the use of an unbiased estimate is of significant importance in achieving the allowed rate of return objective. This provides for the rate of return to be commensurate with the efficient financing costs of a benchmark efficient entity.*
>
> *We do not consider the practice of selecting averaging periods after they have occurred is an effective mechanism for achieving the allowed rate of return objective. This is because choosing the averaging period in advance is important for obtaining an unbiased estimate. By bias, here we mean that at the time the averaging period is selected, it is not known with certainty whether it will result in a higher or lower estimate than the estimate from a different potential averaging period.*
>
> *If an averaging period is chosen after the nominated period has occurred, the knowledge of the return on debt at any past point of time may influence the choice. It would not matter if the period were chosen by the AER, the service provider, a user or consumer, the Australian Competition Tribunal or another stakeholder. We made this clear in the Guideline when we specified the importance of determining an averaging period in advance. In particular, we specified that if a service provider could select an averaging period by looking at historical yields, it could introduce an upwards bias.*

In the above extract from the AER's preliminary determination, the AER misunderstands the relevance of the concept of bias in connection with the decision that it is required to make under the Law and the Rules. An estimate of the return on debt will be 'unbiased' in a relevant sense when it has a value that is commensurate with expected efficient debt financing costs over the relevant regulatory control period.

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838 Chairmont, *Financing Practices Under Regulation: Past and Transitional*, 13 October 2015, p. 13.

839 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-164.

840 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-164.

841 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-190.

To the extent the AER's identification of the efficient financing costs of a BEE is correct, it is common ground that the outcome of the efficient financing practice adopted by that entity is that it will face a trailing average DRP over the regulatory control period. In the prevailing market conditions, the adoption of a methodology to estimate the return on debt that does not calculate the DRP component using a trailing average approach results in a return on debt below that which is commensurate with expected efficient financing costs. This much is accepted by the AER as it notes in respect of its transition:[842]

> *Whether the allowed DRP matches, or is higher or lower than, a benchmark efficient entity's financing cashflows with respect to the DRP component depends on whether the prevailing and historical average DRP is higher, lower, or around the same level as each other.*

In the case of the distribution determination to be made for us, the AER's preliminary determination notes that prevailing interest rates are currently lower than the historical average of interest rates over the past ten years,[843] and therefore the AER's transition results in a DRP that is lower than the AER's BEE's financing cashflows. The AER goes on to state in its preliminary determination that the fact that prevailing interest rates are lower than the historical average of interest rates over the past ten years is simply a consequence of the particular timing of the decision,[844] suggesting that the issue of under-compensation relative to efficient financing costs is an irrelevant matter. However, not only is the AER able to deal with that issue under the Rules and the Law, it is in fact required to deal with it in making its decision. The Rules provide that compensation of the provider for efficient financing costs is determinative in selecting the methodology for estimation of the return on debt.

The AER's decision must be in accordance with the Law, and more specifically, with the NEO and the revenue and pricing principles.[845] The revenue and pricing principles are consistent with and designed to promote the NEO.[846] In discussing the revenue and pricing principles, the Tribunal has previously noted the importance of providing for the recovery of at least efficient costs in the context of efficiency objectives.[847]

> *It is well accepted in the literature of regulatory economics and in regulatory practice that all these efficiency objectives [efficient investment, efficient provision of services, efficient use of system] are in principle met by setting prices for services that allow the recovery of efficient costs, including the cost of capital commensurate with the riskiness of the investment in the assets (infrastructure or 'system', as the term is used in the NEL) used to provide services.*
>
> *It might be asked why the NEL principles require that the regulated NSP be provided with the opportunity to recover at least its efficient costs. Why 'at least'? The issue of opportunity is critical to the answer. The regulatory framework does not guarantee recovery of costs, efficient or otherwise. Many events and circumstances, all characterised by various uncertainties, intervene between the ex ante regulatory setting of prices and the ex post assessment of whether costs were recovered. But if, as it were, the dice are loaded against the NSP at the outset by the regulator not providing the opportunity for it to recover its efficient costs (eg, by making insufficient provision for its operating costs or its cost of capital), then the NSP will not have the incentives to achieve the efficiency objectives, the achievement of which is the purpose of the regulatory regime.*

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842 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-189.

843 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-147.

844 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-147.

845 NEL, section 16.

846 *Application by EnergyAustralia and Others* [2009] ACompT 8 at [75].

847 *Application by EnergyAustralia and Others* [2009] ACompT 8 at [76] - [78].

Thus, given that the regulatory setting of prices is determined prior to ascertaining the actual operating environment that will prevail during the regulatory control period, the regulatory framework may be said to err on the side of allowing at least the recovery of efficient costs. This is in the context of no adjustment generally being made after the event for changed circumstances.

Given the benchmark efficient financing practices the AER considers its BEE would have adopted, which would result in the BEE facing a trailing average DRP over the 2016–2020 regulatory control period, the only basis upon which the AER could permissibly calculate the DRP component of the return on debt otherwise than using a trailing average approach is if the use of that approach would generate a return on debt that is inappropriate, in the sense of being too high or too low having regard to the period in which it is to be applied (being the 2016–2020 regulatory control period).

As noted in the extract from the AER's preliminary determination above, the AER uses the concept of avoiding 'bias' as meaning that, at the time the averaging period is selected, it is not known with certainty whether it will result in a higher or lower estimate than the estimate from a different potential averaging period'.[848] However, the relevant task under the Rules is to estimate the return on debt that contributes to the ARORO. Use of the trailing average approach to estimate the DRP component will not introduce bias because the use of that approach is required by the Rules, as opposed to any foreknowledge of the outcome of selecting that approach on the part of the AER or distributor. Further, the cost of debt under existing facilities - i.e. facilities on foot for time - is a known quantity. The fact that is known does not give rise to 'bias' in any relevant sense.

In any case, to the extent there is foreknowledge of the outcome of selecting the trailing average approach to estimate the DRP component, there is equal foreknowledge of the outcome of selecting the AER's approach. That is, the comparative result of selecting between different approaches to estimating the DRP component was known to, or at least to be expected by, both the distributor and the AER at the time the first debt averaging period for the 2016–2020 regulatory control period was selected. This was so irrespective of the fact that that debt averaging period was yet to occur because prevailing interest rates are currently lower than the historical average of interest rates over the past ten years, as is acknowledged by the AER in its preliminary determination.[849] The only thing that is unknown is the precise extent to which the AER approach to estimating the DRP component will deliver a lower return on debt than the trailing average approach to estimating the DRP. As such, the foreknowledge of relevance to the AER's concern about bias in choosing an approach to estimation of the DRP component (being as to the outcome of selecting between different methods for use in estimating the DRP component) cannot be remedied by applying the AER's transition to the DRP component.

However, it is in fact the application of the AER's transition approach that results in a biased (in the relevant sense) estimate of the return on debt. Given the AER's assumptions as to a BEE's efficient financing practices during and prior to the 2011–2015 regulatory control period, the BEE will face a cost of debt reflecting a 10-year trailing average DRP component. The AER's approach therefore produces a biased estimate of the return on debt insofar as it undercompensates the benchmark efficient operator. It is in this context that the concept of 'bias' has any relevance, not in the sense that the AER has used that concept. To use the words of the Tribunal above, the approach of the AER in its preliminary determination is to 'load the dice' against us at the outset by not providing the opportunity for us to recover our efficient costs by making insufficient provision for the return on debt.

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848 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-190.

849 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-147.

The hybrid transition avoids the bias associated with the AER's transition. As noted in the AER's preliminary determination, the hybrid transition:[850]

> *…provides a good match between the allowed return on debt and a benchmark efficient entity's financing costs over the period it takes a benchmark efficient entity to transition its financing practices to the trailing average approach.*

Once it is accepted that a trailing average approach to the DRP should be taken, there also can be no concerns as to bias or opportunistic behaviour as to selection of averaging periods in light of our submission that the trailing average DRP is calculated by reference to full calendar year averaging periods.

Relevant to the issue of bias is the AER's criticism that the hybrid transition (AER Option 3) and immediate adoption of the trailing average approach (AER Option 4) are 'backwards looking'.[851] However, contrary to the suggestion of the AER that starting with the on the day approach and transitioning to the trailing average approach (AER Option 2) is forward-looking in that each addition to the average occurs at the prevailing rate in an averaging period nominated in advance,[852] a trailing average cost of debt is forward-looking because it is the cost of debt that an entity, which had historically adopted a fixed-rate staggered approach to its debt portfolio, would face now and in the future. An entity in a competitive market would have facilities currently on foot at different interest rates (reflecting the different years in which they were entered into). For example, a distributor might have a facility at seven per cent, a facility at eight per cent, a facility at nine per cent, a facility at 6.5 per cent, and so on. The interest rates payable on these facilities constitute current interest costs and they will continue to be applicable in subsequent years in the regulatory control period (until those facilities expire). These interest costs are in no sense 'backwards looking'. The trailing average approach calculates the cost of debt now, and as it will change over the five year regulatory control period. It is not possible to know at present precisely what the future costs of debt will be—they will be determined in future regulatory years. This is a forward-looking approach.

In regulatory terms, a 'backwards looking' approach is one that involves the regulator looking back over previous regulatory years to see whether the regulatory allowance matched the actual costs of the regulated entity. This is what the AER does in its preliminary determination in appearing to rely on Dr Lally's conclusion that there are some *'accumulated differences'* between the return on debt estimate and the actual return on debt of a BEE arising from prior periods (this issue is discussed further below).[853] Therefore, it is the AER that uses a backwards-looking analysis by seeking to determine if there was some *'windfall gain'* arising from the previous regulatory control period and then using that to reduce the forward-looking return on debt calculated over the forthcoming period.

The ARORO in clause 6.5.2(c) of the Rules is that the rate of return for a distributor is to be 'commensurate with the efficient financing costs of a BEE'. A methodology that estimates the return on debt using a trailing average approach will provide for a return that is commensurate with the financing costs that a BEE will face over the 2016–2020 regulatory control period. It is forward-looking in precisely the manner that is relevant under clause 6.5.2(c) of the Rules.

The AER's debt transition is not forward-looking in the relevant sense required by clause 6.5.2(c) of the Rules. Even in respect of the AER's own BEE, being one that would have entered into swaps to hedge the base rate component of its cost of debt, the AER's transition does not provide for a return on debt that is commensurate

[850] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-164.

[851] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-147.

[852] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-191.

[853] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-180.

with the costs that entity will face over a regulatory control period. This is because this entity would face a trailing average of the DRP component of its cost of debt. The AER's transition is designed to provide a lower allowance in respect of the notional DRP component of the cost of debt over the 2016–2020 regulatory control period (and beyond). There are two fundamental difficulties with the AER's approach, which are discussed below under the 'NPV= 0' topic. These are:

- first, the AER considers that its approach is authorised by the NPV=0 approach to account for assumed positive 'accumulated differences' arising from previous regulatory periods. However, the regulatory regime does not permit 'true-ups' of this kind based on an ex post review of the regulatory allowance provided for a particular component of a building block and the costs that were actually incurred by the service provider in respect of that component; and
- secondly, there is no reasoned basis upon which a view can be formed as to whether there has been over-recovery and if so, the quantum of this over-recovery.[854]

NPV = 0

The second drawback that the AER concluded arises under a hybrid transition is that it can create a mismatch between the allowed return on debt and the efficient financing costs of a BEE over the life of its assets. The AER stated:[855]

> *Transitioning from the on-the-day approach using the hybrid transition can create a mismatch between the allowed return on debt and the efficient financing costs of a benchmark efficient entity over the life of its assets. The change in the regulatory regime can therefore create windfall gains or losses to service providers or consumers. Windfall gains or losses do not result from a service provider's efficient or inefficient decisions. In effect, they are a side effect of changing the methodology for estimating the return on debt at a particular point in time. They should be avoided, so that economic regulatory decisions deliver outcomes based on efficiency considerations, rather than timing or chance.*

In the AER's preliminary determination, the AER notes that the Law requires it to take into account that a regulated service provider should be provided with a reasonable opportunity to recover at least its efficient costs.[856] Based on advice from Dr Lally, the AER considers that the principle that a service provider be provided with a reasonable opportunity to recover at least its efficient costs is equivalent to the NPV principle. [857] The AER explains that the NPV principle is that the expected present value of a BEE's regulated revenue should reflect the expected present value of its expenditure, plus or minus any efficiency incentive rewards or penalties.[858]

In his advice to the AER, Dr Lally stated that the requirement in the Rules that the return on debt be commensurate with the efficient financing costs of a BEE is 'not sufficiently precise to be readily implemented and therefore requires formalizing'.[859] However, it is unclear why Dr Lally considers the requirement as stated in the Rules to be imprecise. The requirement is simply stated and does not require any overlay or 'formalisation' in

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[854] See AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-183, where the AER states: 'due to the unavailability of reliable older data, we are unable to draw reliable conclusions about accumulated windfall gains or losses in preceding regulatory periods'. Also: Chairmont, *Financing Practices Under Regulation: Past and Transitional*, 13 October 2015, p. 38, where Chairmont says: 'it is concluded that there is insufficient history of relevant BBB bond data to measure over and under compensation for an adequate time period to come to any definitive conclusion about the net result over the life of energy assets'.

[855] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-165.

[856] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-173.

[857] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-173.

[858] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-173.

[859] Lally, *Review of Submissions on the Cost of Debt*, April 2015, p. 19.

order for it to be implemented. What is required is to ascertain efficient financing costs (which as stated above are the costs that would be expected in a workably competitive market or, if that position is incorrect, the costs that would be incurred having regard to the AER's assumptions about the financing practices of a BEE under the on-the-day approach to estimating the return on debt) and to design a methodology for estimating the return on debt which, insofar as possible, matches those costs.

The AER speaks very generally about NPV *'over the life of the assets'*, but does not actually identify what life and what assets, and how any particular debt instrument relates to the life of any particular asset. The relevant asset here is the RAB of the regulated entity. The asset base is made up of thousands of assets, with lives ranging from five or fewer years to sixty years. The regulatory regime, as applied by the AER, assumes that for a BEE 60 per cent of the RAB is funded by debt. Debt is not raised in respect of particular assets. Debt instruments do not attach to specific assets. Rather, in respect of the BEE it is assumed that there is simply a portion of the asset base that is funded by debt, and, in accordance with the debt / equity ratio assumed under the regulatory regime, the BEE takes out debt instruments to fund the relevant proportion of its asset base. In this way it is nonsensical to talk about NPV over the life of the assets. To the extent there is a relevant *'asset'* in a NPV = 0 context, it is the asset base, the life of which, for all practical purposes, is indeterminate and indefinite.

The NPV principle cannot be used to override the requirements in the Law and the Rules, in particular:

- the revenue and pricing principles—which require that a service provider should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control services; and
- the ARORO (clause 6.5.2(c) of the Rules)—which requires that the rate of return for a distributor is to be commensurate with efficient financing costs.

These requirements apply to the decision that the AER is required to make for the 2016–2020 regulatory control period. That is, the service provider is to be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control services in the 2016–2020 regulatory period and the rate of return is to be commensurate with efficient financing costs the service provider will incur in the 2016–2020 regulatory control period. As set out below, this follows as a matter of statutory construction.

Section 16(1) of the Law requires the AER to make a distribution determination in a manner that will or is likely to contribute to the achievement of the NEO. Section 16(2) of the Law requires the AER to take into account the revenue and pricing principles when exercising a discretion in making those parts of distribution determination relating to direct control network services. The AER is bound to do this in respect of each individual distribution determination it makes. That is, section 16 of the Law does not require the AER to make determinations for a service provider over some indefinite period of time that collectively or overall contribute to the achievement of the NEO, and take into account the revenue and pricing principles. Such an interpretation would be absurd, including because it would purport to authorise the AER to provide a service provider with less than efficient costs in some periods, and more than efficient costs in other periods, which is clearly inconsistent with the regulatory framework established by the Law and the Rules. Yet this is how the AER seeks to apply the NPV=0 principle in applying its transition to the DRP component of the return on debt.

Various provisions in the Rules also make clear that the distribution determination is in respect of a regulatory control period and that the forecasts and estimates used to determine allowed revenues are based on the best estimate of forecast costs over the regulatory control period. For example, the provisions relating to the making of the building block determination refer to determining the annual revenue required for each year of the regulatory control period.[860] Specifically, in connection with the rate of return, clause 6.5.2(a) of the Rules refers to the return on capital for each regulatory year being calculated by applying a rate of return for that regulatory

[860] NER, clause 6.4.3(a).

year which is determined in accordance with clause 6.5.2 of the Rules. This last provision indicates that the task is to determine a rate of return for each regulatory year of the regulatory control period that satisfies the requirements of the Rules (including the ARORO), not determining a rate of return that satisfies those requirements over some other, unspecified, period.

In the AER's preliminary determination, the AER concludes that its transition provides a BEE with a reasonable opportunity to recover efficient financing costs over the life of its assets, whereas the hybrid transition does not. It is unclear from the AER's preliminary determination precisely what finding underpins this conclusion.[861] In particular:

- the AER explicitly concludes that it has *'not relied on the historical balance of over or under recoveries'* in making its decision[862]—which suggests that this conclusion does not rest upon a finding as to the existence of any accumulated windfall gains or losses; and
- yet, at the same time, under the heading 'fairness of returns in expectation' the AER also appears to rely on analysis conducted by Dr Lally which Dr Lally claimed demonstrated that the AER's transition *'allows the regulatory regime to account for accumulated differences between the return on debt estimate and the actual return on debt of a BEE'*.[863]

We submit that it is impermissible for the AER to take into account differences between the allowed return on debt and the actual return on debt faced by a benchmark service provider in previous regulatory control periods in calculating the return on debt for the 2016–2020 regulatory period (for the reasons discussed below). However, even assuming it was permissible for the AER to do so, in order for the AER to find that the application of its transition to the DRP component of the return on debt provides a BEE with a reasonable opportunity to recover efficient financing costs over the life of its assets, the AER must find that the benchmark service provider enters into the 2016–2020 regulatory control period with a positive accumulated difference between the allowed return on debt and the actual return on debt faced by the benchmark service provider in previous regulatory periods. The AER has not done this.

The AER states that it can conclude with a *'reasonably high degree of confidence'* that the benchmark operator would have been overcompensated over the previous regulatory control period.[864] However, the material referred to by the AER does not support such a conclusion for us.

The AER ultimately concedes that it is *'unable to draw reliable conclusions about accumulated windfall gains or losses in preceding regulatory control periods'*.[865] This finding is supported by Chairmont's October 2015 report.[866] Therefore, in circumstances where it is common ground that the application of the AER's transition to the DRP component of the return on debt will result in the AER's BEE being under-compensated in the 2016–2020 regulatory control period, it cannot be concluded that the AER's transition provides a BEE with a reasonable opportunity to recover efficient financing costs over the life of its assets. Assuming any such *'look back'* was permissible, such a conclusion could only be drawn if the benchmark service provider has *'accumulated'* gains (i.e. has been *'overcompensated'* for the return on debt in previous regulatory periods) at the commencement of the 2016–2020 regulatory control period and that the gains over prior periods are precisely offset by the anticipated shortfall in the return on debt during the 2016–2020 regulatory control period.

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861 This conclusion is set out in AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-184 (Table 3.23).

862 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-184.

863 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-180 to 3-181.

864 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-182.

865 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-183.

866 Chairmont, *Financing Practices Under Regulation: Past and Transitional*, October 2015, pp. 38-39.

In any case, as a matter of construction, the statutory regime does not permit the AER to seek to 'clawback' differences between the allowed return on debt and the actual return on debt faced by a benchmark service provider in a prior regulatory control period. A fundamental principle of the regulatory regime is that it embodies incentive regulation. Under incentive regulation, regulated revenues are set ex-ante and firms have an incentive to reduce costs to outperform regulated revenues such that over time regulated revenues are expected to converge to the efficient level. Once the regulatory allowance has been set, ex post adjustments are not made to that regulatory allowance based on differences between forecasts and actual costs, other than for the impact of inflation on the RAB.[867]

Consistent with the incentive regulation basis of the regime established by the Rules, the task of setting a regulatory allowance for a regulatory control period prescribed by the Rules is a forward-looking one. Pursuant to the building blocks approach set out in clause 6.4.3(a) of the Rules, there are only a few specified matters that may have occurred in a prior regulatory control period that have any relevance to the calculation of the regulatory allowance in the subsequent regulatory control period. There are two discrete matters:

- the value of the RAB; and
- revenue increments and decrements arising from the application of any relevant incentive scheme, or from the application of a control mechanism in the previous regulatory control period.[868]

With the exception of these two matters, the regulatory framework does not operate in a manner that looks back at what has happened in a previous regulatory control period in order to calculate the annual revenue requirement for a service provider for each regulatory year of a period in an attempt to capture some prior difference between allowable revenues and costs. Rather, the regulatory framework is designed and operated in such a way that once regulated allowances are set, they are taken to be the efficient allowance for the BEE and there can be no retrospective adjustments for departures from this allowance.

As regulated entities could not match the DRP component of their debt costs to the regulatory allowance for the return on debt under the on-the-day approach, it was inevitable that there would be a mismatch between any debt costs incurred by a benchmark regulated entity and the return on debt allowance for that entity. However, that was simply a consequence of the regulatory approach—the allowance was the allowance and regulated entities were required to manage their operations in accordance with that allowance. This much is accepted by the AER:[869]

> *Incentive based regulation uses the combination of financial rewards and penalties to promote efficient behaviour. In particular, it means that where a service provider:*
>
> *matches the efficient regulatory benchmark—it recovers its efficient costs. We consider this would be the outcome for the benchmark efficient entity. As it operates efficiently, it would recover its efficient costs.*
>
> *does not match the regulatory benchmark—it keeps the financial benefits or financial detriments that flow from its actions. An example of this would be where a service provider is able to source debt at rates cheaper than the allowed return on debt it is able to keep the difference.*

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[867] Even where the Rules permit ex post review of actual expenditure, they do not permit any ex-post adjustment to be made to the regulatory allowance that was set in the distribution determination. See NER, clause S6.2.2A which permits reductions to the amount of capital expenditure that would otherwise be added to the regulatory asset base where the AER has found that the expenditure does not reasonably reflect the capital expenditure criteria. The threshold to be passed before any such reduction can be made is that the sum of all capital expenditure incurred during the relevant review period exceeds the sum of the forecast capital expenditure accepted or substituted by the AER for the review period, and any reduction cannot be greater than this amount (clause S6.2.2A(g) of the Rules).

[868] NER, clauses 6.5.1(e), and 6.4.3(a)(5) and (6).

[869] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-170.

adopts a risk position which is either higher or lower risk than that embedded in the regulatory process—it keeps the financial benefits or wears the financial detriments that flow from its actions.

The Rules require that the rate of return for a regulatory control period is commensurate with the efficient financing costs of a BEE. As noted by Professor Gray:[870]

The new Rules state that for each determination the allowed rate of return must be commensurate with the efficient financing costs of a benchmark efficient entity. The Rules do not provide for an exception in cases where the regulator considers that it should set the allowed return to be different from the efficient financing costs of a benchmark efficient entity in order to square up the regulator's assessment of any windfall gains or losses from prior regulatory periods.

Professor Gray notes the following further problems with the AER's decision to seek to erode the perceived windfall gain:

- the amount of any gain to be eroded or 'clawed back' will depend on how many prior regulatory periods are included in the regulator's mental accounting. It is possible that any perceived windfall gain that may have been accrued in the prior regulatory period has already been squared up by shortfalls in prior regulatory periods preceding the prior regulatory period;[871] and
- the perceived windfall gains may have been balanced out by other features of the prior regulatory determination. In periods where investors are requiring higher risk premiums on debt investments in the benchmark firm, for example, they will also be requiring higher ERPs in the same benchmark firm. However, the AER's approach has been to use an essentially fixed MRP in its allowed return on equity.[872]

The imposition of the AER's transition is also at odds with the 2012 Rule Amendment, which is directed at better matching the regulated return on debt (and the overall rate of return) with costs that would be incurred pursuant to efficient financing practices. As noted by the AER's consultants, with respect to the DRP component of the return on debt, there is no mismatch between the cost incurred by the benchmark efficient firm and that allowed by a trailing average approach after the regime change. As such, no transitional method appears to be warranted and, if one was used, Lally notes, it would introduce a mismatch that would not otherwise arise.[873]

In summary, the AER's NPV=0 justification:

- is inconsistent with the ARORO which, as noted above, requires that the allowed rate of return for each regulatory year reflects the efficient financing costs of a BEE for that year;
- is inconsistent with the NEO and the revenue and principles which demand that a service provider be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing regulated services; and
- introduces regulatory risk and is inconsistent with incentive-based regulation in that it introduces an ex post adjustment mechanism after a regulated firm has benefited from operating in a way that the regulator itself considers to be efficient.

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870 SFG, *Return on Debt Transition Arrangements under the NGR and NER: Report for Jemena Gas Networks, Jemena Electricity Networks, Citipower, Powercor and United Energy*, 27 February 2015, p. 4.

871 SFG, *Return on Debt Transition Arrangements under the NGR and NER: Report for Jemena Gas Networks, Jemena Electricity Networks, Citipower, Powercor and United Energy*, 27 February 2015, p. 26.

872 SFG, *Return on Debt Transition Arrangements under the NGR and NER: Report for Jemena Gas Networks, Jemena Electricity Networks, Citipower, Powercor and United Energy*, 27 February 2015, pp. 25-26.

873 Lally, *Transitional Arrangements for the Cost of Debt*, 24 November 2014, p. 7.

In any event, there is no evidence that adopting a hybrid transition would violate the NPV=0 principle, as claimed by the AER. This is because, as acknowledged by the AER and as advised by Chairmont, it cannot be ascertained with any certainty the extent to which there are accumulated windfall gains or losses from prior periods.

In short, imposing a transition for the DRP component of the return on debt where that component cannot be hedged under the on-the-day approach is inconsistent with the NEO, the revenue and pricing principles, and the requirements of the Rules. In particular, it will not provide a BEE with a return on debt that is commensurate with efficient financing costs or provide a reasonable opportunity to recover at least the efficient costs the BEE incurs in providing direct control services.

Other matters relied on by the AER in support of its transition

The AER finds that its transition has two further positive attributes, in addition to providing a service provider with a reasonable opportunity to recover its efficient financing costs over the life of its assets and being unbiased. These are that the transition:

- maintains the outcomes of the service provider's past financing decisions, consistent with the principles of incentive regulation; and
- avoids practical problems with the use of historical data 'as estimating the return on debt during the GFC is a difficult and contentious exercise'.[874]

Dealing with the second point first, the AER itself notes that it is satisfied that 'this is a relatively minor issue'.[875] The issue of historical data needed to estimate the trailing average approach concerns the DRP component of the return on debt, and relates only to the selection of which data source to use, as opposed to the data not being available at all.[876] The AER's consultant, Chairmont, does not note any particular difficulty with the use of historical data to estimate a return on debt using the trailing average approach and states that it is likely that a reasonable estimate could be determined.[877]

The AER's finding that maintaining the on-the-day approach is consistent with incentive regulation is illogical. The AER states that effective ex ante incentive regulation relies on service providers understanding and accepting the financial consequences of their decisions at the time they make those decisions.[878] However, the AER acknowledges that service providers have limited control over the DRP component of the cost of debt. As such, as a general matter, there is no relevant incentive relating to this component with respect to which service providers could be said to have 'understood and accepted the financial consequences of their decisions'. Therefore, to the extent maintenance of outcomes of past financing decisions consistent with principles of incentive regulation is relevant, it does not support either the continuation of the on-the-day approach or the AER's transition. It does however support a hybrid transition because, as noted by the AER, application of such a transition would maintain the incentive that service providers should reduce risks that are within their control.[879]

Managing interest rate risk and the optimal hedge ratio

If, contrary to our proposal, a transition is applied to the base rate, then it is necessary to consider to what degree hedging would be efficient. A transition can only apply to the base rate component to the extent that the BEE used hedging to match the previous on-the-day approach to setting the allowed return on debt, and one

874 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-163.

875 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-163.

876 Lally, *Transitional Arrangements for the Cost of Debt*, 24 November 2014, p. 15.

877 Chairmont, *Cost of Debt: Transitional Analysis*, April 2015, p. 47.

878 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-171.

879 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-172.

cannot simply assume (as the AER does) that 100 per cent of that component was hedged under that approach without evidence to support it.

The evidence demonstrates that the efficient level of hedging under the previous on-the-day approach was significantly less than 100 per cent. Empirical analysis by CEG demonstrates a hedging ratio of approximately one third would have minimised interest rate risk.[880] CEG builds on analysis presented by Dr Lally for the AER in assessing debt management strategies, by correcting a critical error in the form of Dr Lally's inclusion of US data prior to 1986 (a period over which high a volatile inflation invalidates his methodology), as well as by making amendments to correct for other weaknesses in Dr Lally's methodology (including Dr Lally's failure to use Australian data).[881] CEG also confirms that the resulting optimal hedging ratio of one third arising from this analysis is broadly consistent with the estimates that are derived from the Australian dataset.[882]

In a further expert report accompanying this revised regulatory proposal, CEG considers and responds to criticisms made by Chairmont and Professor Lally of this analysis. Following this review of the Chairmont and Lally reports, CEG's view as to the optimal hedging ratio under the previous on-the-day approach is unchanged.[883]

Conclusion

For the above reasons, we consider that the trailing average approach should be implemented immediately, with no transition.

Alternatively, if the AER's approach of estimating efficient financing costs by reference to the financing practices that would emerge under regulation were correct, the appropriate approach would be to adopt a hybrid form of transition where only the hedged base rate component of the return on debt is subject to a transition. This is because the AER has concluded that under the on-the-day approach, an efficient financing practice would have been to engage in hedging of the base rate. By contrast, the AER has conceded that the DRP component cannot be—and could not have been in the past—hedged, with the result that there is no reason for a transition to be applied to it.

If a transition is applied to the base rate, then it is necessary to consider to what degree hedging would be efficient. A transition can only apply to the base rate component to the extent that the BEE used hedging to match the previous on-the-day approach to setting the allowed return on debt, and one cannot simply assume that 100 per cent of that component was hedged under that approach without evidence to support it.

As described above, the evidence demonstrates that the efficient level of hedging under the previous on-the-day approach was significantly less than 100 per cent. Empirical analysis by CEG demonstrates a hedging ratio of approximately one third would have minimised interest rate risk.

Therefore, if an optimal hedge form of hybrid transition is to be adopted (i.e. if the AER's view of efficient financing costs were correct), the transition should only apply to one third of the base rate, reflecting the extent to which a BEE would have been expected to hedge the base rate component.

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880 CEG, *Efficient Use of Interest Rate Swaps to Manage Interest Rate Risk*, June 2015; CEG, *Critique of the AER's approach to transition*, January 2016.

881 CEG, *Efficient Use of Interest Rate Swaps to Manage Interest Rate Risk*, June 2015 at [5] - [9], sections 4 and 5.

882 CEG, *Efficient Use of Interest Rate Swaps to Manage Interest Rate Risk*, June 2015 at [10],

883 CEG, *Critique of the AER's approach to transition*, January 2016

Benchmark credit rating and term

Credit rating

We consider that adopting a BBB+ credit rating assumption is highly conservative, in the sense that it is likely to understate the degree of risk faced by us in the supply of standard control services.

The empirical evidence referred to by AER in support of a BBB+ rating, when correctly applied and interpreted, supports a BBB to BBB+ rating. As noted by the AER, the median credit rating over the past ten years (2006 - 2015) across all businesses in the AER's sample is BBB to BBB+.[884] A credit rating of BBB to BBB+ is also consistent with the advice from Professor Lally to the AER.[885]

Therefore, adoption of a BBB+ credit rating assumption is likely to lead to under-estimation of the efficient financing costs of a BEE facing a similar degree of risk as that which applies to us in respect of the supply of standard control services. In short, we may be inadequately compensated for efficient financing costs, creating a risk that we cannot attract the capital required to undertake efficient investment.

We note that if a broad BBB band data series is available and is used to estimate the return on debt then whether a BBB or BBB+ credit rating assumption is adopted is of little practical consequence. However if the AER were to start using a BBB+ specific data series (should one become available), it is likely that this would lead to under-estimation of the efficient financing costs of a BEE facing a similar degree of risk as that which applies to us in respect of the supply of standard control services. This is because a BBB+ specific data series is likely to over-estimate the cost of debt for businesses with a risk profile in the BBB to BBB+ band.

For the same reasons, continuing to use a broad BBB band data series to estimate the return on debt is not materially 'favourable' to us, as suggested by the AER.[886] Rather, given that the evidence supports a credit rating of BBB to BBB+, use of a broad BBB band data series is entirely appropriate.

Term

Empirical evidence continues to support a benchmark term of debt of ten years. This includes evidence for Australian energy network businesses, and for businesses operating in other sectors and jurisdictions facing a similar degree of risk.[887]

We do not agree with the statement in the AER's preliminary determination that a ten year term assumption is more likely to overstate than understate the debt term (and therefore, the efficient financing costs) of a BEE.[888] A ten year term assumption properly reflects the efficient financing practices of a BEE facing a similar degree of risk to that faced by us in the provision of standard control services.

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884 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-591 (Table 3-70).

885 Lally, *Implementation issues for the cost of debt*, November 2014, p. 4.

886 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 50.

887 PwC, *Energy Networks Association: Benchmark term of debt assumption*, June 2013. Based on a sample including Australian, UK and US businesses operating in the energy and water sectors, PwC concluded that such businesses issued debt with a weighted average term in the range of 10 to 21 years.

888 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-212.

Estimation of the prevailing return on debt

Use of independent third party data series

In the RoR Guideline, the AER indicated that it proposed to use published yields from an independent third party data service provider to estimate the return on debt, without specifying which source it intended to use.[889] The AER stated that using a third party data service provider has the following advantages:[890]

- third party data sources are provided for use by market practitioners and developed independently from the regulatory process;
- third party data sources are constructed by finance experts with access to a comprehensive financial database, where judgements are made in terms of debt instrument selection and any necessary adjustments to yields;
- using an independent third party source reduces the scope for debate on debt instrument selection issues and curve fitting or the use of some form of averaging method to derive the estimate of the return on debt; and
- a third party data source can be more readily implemented in the context of automatically updating a trailing average of the return on debt as required by the Rules.

In its preliminary determination, the AER added to its reasons that there is no consensus among Australian regulators on the best method to estimate the return on debt (that is, some regulators use independent data service providers while others use their own data series) and the Tribunal has found both approaches are reasonable.[891]

We agree with the AER's approach of using published yields from an independent third party data service provider or providers to estimate the return on debt.

Choice of third party data series, extrapolation method and other adjustments

While at the time the RoR Guideline was published the AER was using the BBB seven year Bloomberg fair value (**BFV**) curve, extrapolated to a ten year maturity, the AER:[892]

- acknowledged the known issues with the dataset and the lack of transparency around the methodology used by Bloomberg; and
- noted that it was expected that the RBA would publish estimates for return on debt, the methodology for which the AER stated '[i]mportantly … will be transparent'.

In November 2013, Bloomberg started publishing its BVAL curve series, which was intended to replace the BFV curve series which was retired in May 2014.[893] The longest published term to maturity for the BVAL curve series for some time was seven years.[894] However, as of 14 April 2015, Bloomberg revised its methodology for the BVAL curve and recommenced publishing a ten year yield estimate.[895]

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889 AER, *Rate of return guideline*, December 2013, p. 21.

890 AER, *Explanatory statement, Rate of return guideline*, December 2013, pp. 126 -127.

891 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-219.

892 AER, *Explanatory statement, Rate of return guideline*, December 2013, p. 128.

893 ACCC Regulatory Economic Unit, *Return on debt estimation: a review of the alternative third party data series*, August 2014, p. 3.

894 ACCC Regulatory Economic Unit, *Return on debt estimation: a review of the alternative third party data series*, August 2014, p. 3.

895 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-222 (footnote 716).

In December 2013, the RBA published an article presenting a method for estimating the aggregate credit spreads of A rated and BBB rated bonds issued by the Australian non-financial corporations across a range of maturities (including ten years to maturity) and indicating the RBA would commence publishing monthly credit spreads estimates.[896] The AER referred to this paper in its issues paper on the choice of third party data service provider for estimating the return on debt published in April 2014.[897]

In its preliminary determination, the AER determined to adopt the same approach it had adopted in all decisions since the RoR Guideline was published, that is, to use a simple average of:[898]

- the ten year estimate from the non-financial corporate BBB rated data series published by the RBA (extrapolated from a 'target' ten year term to an 'effective' ten year term using the method recommended by Dr Lally); and
- the ten year yield estimate from the BVAL data series published by Bloomberg (converted from a semi-annual to an effective annual rate).

The AER stated that it was satisfied that a simple average of the two curves will result in a return on debt that contributes to the achievement of the ARORO because:[899]

- based on analysis of its bond selection criteria, the AER considered that the approaches employed by the RBA and Bloomberg have their unique strengths and weaknesses but neither is clearly superior;
- based on analysis of the curve fitting methodologies, the AER considered that the approaches employed by the RBA and Bloomberg have their unique strengths and weaknesses but neither is clearly superior;
- both curves require adjustments from their published form to make them fit-for-purpose and the AER was not satisfied that either can be more simply or reliably adjusted to estimate the return on debt;
- a simple average is consistent with advice from Dr Lally that the AER adopt a simple average;
- the two curves have regularly produced materially different results at particular points in time and there is no indication that one curve produces systematically higher or lower estimates than the other;
- a simple average of the two curves, in these circumstances, is consistent with the reasoning of the Tribunal in *Application by ActewAGL Distribution* [2010] ACompT 4 (in which it stated (at [78]) that if the AER cannot find a basis upon which to distinguish between the published curves, it is appropriate to average the yields provided by each); and
- a simple average of the two curves will reduce the likely price shock if either curve becomes unavailable or produces erroneous estimates during the period.

The AER referred to and relied on the analysis in, and referred to in, its draft decision in respect of JGN.[900]

We engaged CEG to assess the AER's preliminary determination in relation to the most accurate source from which to derive an estimate of the return on debt. CEG's report, *Criteria for assessing fair value curves*, is attached to our revised regulatory proposal.[901]

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[896] Arsov, Brooks and Kosev, *New measures of Australian corporate credit spreads*, December 2013.

[897] AER, *Return on debt: Choice of third party data service provider, Issues paper*, April 2014.

[898] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-221 to 3-222.

[899] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-224 to 3-225.

[900] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-225.

[901] CEG, *Criteria for assessing fair value curves*, January 2016.

CEG has developed criteria to assess different sources of estimates for the ten year BBB cost of debt, and has assessed each of the available third party data sources against these.[902] CEG concludes that the RBA's data series performs well on all of its criteria, whereas Bloomberg performs poorly.[903] The reasons for CEG's conclusions are described in detail in its report.

Nonetheless, for the purposes of responding to the AER's preliminary determination, we have not sought to exclude the use of Bloomberg's data series. In light of the publication by Reuters of a BBB curve, however, we now propose the use of a weighted average of the RBA, BVAL and Reuters curves for the purposes of estimating the prevailing return on debt for the regulatory years 2016 and beyond. For the purposes of estimating the prevailing return on debt for each of the years included in the trailing average prior to this, we propose the use of a simple average of the RBA and Bloomberg curves.

Reuters has published ten year estimates on a daily basis from 25 May 2015.[904] The publication of these estimates post-dates the submission of our regulatory proposal and thus was not reflected in our proposal. Its publication also post-dates the AER's draft decision in respect of JGN (dated November 2014), which is relied on by the AER in support of its preliminary determination.

The Reuters curve shares all of the advantages cited by the AER in respect of the BVAL curve. Given the flaws in Bloomberg's data series highlighted by CEG, there is no basis for concluding that the BVAL curve is clearly superior to the curve published by Reuters. However, according to CEG both these curves do not include foreign currency bond despite the 'industry norm' clearly being that foreign currency issues dominate long term bond issues by regulated utilities and the wider set of Australian businesses with credit rated debt. On the other hand, CEG finds RBA curve includes a large number of foreign currency bonds and is also the best performer against its criteria which it believes will promote the ARORO[905]. Accordingly, we propose using a weighted average of the three data curves with 50% weight to RBA, 25% to BVAL and 25% to Reuters. That is, for the purposes of estimating the prevailing return on debt for the 2016 regulatory year and beyond, we propose the use of a weighted average of all three curves.

The reason for giving RBA higher weight than BVAL and Reuters is because it is best performer against the criteria identified by CEG and the reason for giving equal weight (25% each) to BVAL and RBA is that Reuters' performance against the relevant criteria is at least as good at Bloomberg's performance. Neither the AER nor its consultant Dr Lally has considered the possible use of the Reuters curve. To the extent the AER does not accept our proposal to include it in the average for the purposes of estimating the prevailing return on debt for the 2016 regulatory year and beyond, we should be informed of any concerns the AER has with using the Reuters curve and provided with an opportunity to respond to these.

We note that we do not press for a goodness of fit test to select the extrapolation methodology and have adopted the AER's adjustments to the RBA and the BVAL curves in its preliminary determination.

We also propose that, for the purposes of determining the prevailing cost of debt for each of the years prior to 2016 included in the trailing average (i.e. 2007 to 2015), the averaging period be a full calendar year averaging period.

[902] CEG, *Criteria for assessing fair value curves*, January 2016.

[903] CEG, *Criteria for assessing fair value curves*, January 2016.

[904] CEG, *Criteria for assessing fair value curves*, January 2016.

[905] CEG, *Criteria for assessing fair value curves*, January 2016.

Contingencies for the choice of data series

In light of our revised proposal to use a weighted average of the RBA, BVAL and Reuters curves for the purposes of estimating the prevailing return on debt for the 2016 regulatory year and beyond, adjustments to the contingencies set out by the AER in its preliminary determination are required. We set out in the table below our proposed amendments to the contingencies identified in the AER's preliminary determination.[906]

Table 10.11 Our proposed amendments to contingency approaches to choice of data series

Event	Changes to approach
~~Either~~ Any of the RBA ~~or~~, Bloomberg or Reuters ceases publication of Australian yield curves that reflect a broad BBB rating.	We will estimate the annual return on debt using the remaining curves or curve.
A different third party commences publication of a 10 year yield estimate.	We will not apply estimates from a third party data provider that we have not evaluated and included in our final decision approach. We will consider any new data sources in future determinations.
~~Either~~ Any of the ~~Bloomberg or~~ RBA, Bloomberg or Reuters substitutes its current methodology for a revised or updated methodology.	We will adopt the revised or updated methodology. Then, at the next regulatory determination, we will review this updated methodology. As noted above, we would also review any new data sources. However, if ~~Bloomberg or~~ the RBA, Bloomberg or Reuters backcasts or replaces data using a revised or updated methodology we will not use the backcasted data to re-estimate our estimates of the prevailing return on debt for previous years. This would be impractical and would create regulatory uncertainty over whether the allowed return on debt would at some point in the future be re-opened. Instead, we will continue to use the ~~Bloomberg or~~ RBA, Bloomberg or Reuters data that we downloaded at the time of estimating the prevailing return on debt for that point in time.
Bloomberg or Reuters reduces the maximum published BVAL or Reuters curve term respectively from 10 years,.	If Bloomberg or Reuters still publishes the BVAL or Reuters curve respectively to 5 or more years, we will extrapolate ~~the BVAL~~ that curve from the longest published term using the 5 to 10 year yield margin from the RBA curve. If Bloomberg or Reuters no longer publishes the BVAL or Reuters curve respectively to 5 years, we will rely entirely on the ~~RBA~~ curve of the other third party or parties.
The RBA ceases publication of a 10 year yield estimate.	If the RBA ceases publication of a 10 year yield estimate, we will extrapolate the RBA estimate to 10 years using: • if available, the average margin between spreads in the Bloomberg and Reuters curve, from the RBA's longest published target term to 10 years • otherwise, the actual CGS margin from the RBA's longest published estimate to 10 years, plus the average DRP spread for the same term margin over the last month prior to the end of its publication.
The RBA commences publication of daily estimates.	We will cease interpolating the RBA monthly yields. Instead, we will estimate both the RBA yield and the RBA year extrapolation margin (used with the BVAL curve) using these daily estimates.
~~Either Bloomberg or the RBA publishes a BBB+ or utilities specific yield curve.~~	~~We will adopt the BBB+ or utilities curve in place of the provider's existing curve, on the basis that it is a closer fit to our benchmark efficient entity.~~

Source: AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015

[906] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-225.

Averaging periods and annual debt updating process

The AER accepted our proposed debt averaging period for the 2016 regulatory year, but did not accept our proposed process to nominate averaging periods for the subsequent regulatory years in the 2016–2020 regulatory control period, adopting instead our alternative proposed averaging periods for those regulatory years.[907]

We do not press our proposed process to nominate averaging periods and propose to adopt the averaging periods for the 2016–2020 regulatory control period accepted in the AER's preliminary determination.

We also revise our proposal to align with the AER's annual debt updating process as outlined in the preliminary determination.[908]

Swap transaction costs if a transition is applied

If, contrary to our proposal, a transition to the trailing average approach to estimating the return on debt is applied by the AER, it is necessary to take into account the transaction costs of entering swap contracts in estimating the return on debt. In our regulatory proposal, we proposed swap transaction costs of 23 basis points consistent with estimates produced by CEG.[909]

In its preliminary determination, the AER rejected these costs for the following reasons:[910]

- The AER was not satisfied that customers should pay for the reduction in interest rate risk that results from hedging.
- The AER has not, historically, provided an allowance for transaction costs associated with swap transaction costs on the basis that service providers receive 'fair compensation' given they were compensated based on:
  - a broad broad BBB credit rating even though the benchmark credit rating was BBB+; and
  - a 10 year debt term even though the benchmark efficient entity would have incurred a five year risk free rate due to hedging.

The AER stated that it has considered this issue in prior decisions.[911]

The reasons put forward by the AER have no basis, for the reasons outlined by CEG in its report submitted with our revised regulatory proposal.[912]

We note that the AER's analysis fails to take into account the advice that its own advisor, Chairmont, provided to the ERA for the purposes of a decision that post-dated the expert material relied on, and the prior decisions referred to by, the AER in its preliminary determination.

Chairmont advised that (in circumstances where an on-the-day approach to estimating the base rate is used, but the DRP is estimated by reference to a ten year trailing average DRP) conceptually it is correct to include hedging costs in the total cost of debt as it encourages sound risk management and supports efficient financing

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907 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-244.

908 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-250.

909 CitiPower, *Regulatory proposal 2016–2020*, April 2015, pp. 238-239.

910 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 3-572 to 3-573.

911 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-573.

912 CEG, *Critique of the AER's approach to transition*, January 2016.

practices.[913] Chairmont calculated a total hedging cost allowance for a full debt portfolio of 11.5 basis points per annum.[914]

In the event the AER rejects our proposal to immediately apply a trailing average approach to estimating the return on debt, and a form of transition is imposed, we consider that swap transaction costs need to be reflected in the return on debt estimates and propose Chairmont's estimate of 11.5 basis points per annum be used for this purpose. CEG noted that Chairmont's estimate is a conservative measure of the swap transaction costs.[915]

Calculation of the indicative trailing average return on debt for 2016

We set out in the table below the inputs to the indicative trailing average return on debt for the first regulatory year in the 2016–2020 regulatory control period (2016). As noted above, for the purposes of estimating the prevailing return on debt for each of the years 2007 to 2015, we use a simple average of the RBA and Bloomberg curves, while for the purposes of estimating the prevailing return on debt for 2016, we use a weighted average of the RBA, BVAL and Reuters curves. The averaging period for the first nine years of the trailing average are the full calendar years 2006 to 2014. The averaging period for the final year is a sample averaging period of the 20 business days to 30 September 2015 (which will need to be updated by reference to our actual averaging period accepted by the AER). All estimates are based on the AER's extrapolation methodology in our preliminary determination.

Table 10.12 Inputs to the trailing average return on debt for 2016

Regulatory year	Averaging period	Swap rate (base rate)	DRP	Return on debt
2007	01/01/2006 to 31/12/2006	6.077	0.643	6.720
2008	01/01/2007 to 31/12/2007	6.639	0.941	7.580
2009	01/01/2008 to 31/12/2008	6.659	2.972	9.631
2010	01/01/2009 to 31/12/2009	5.591	3.946	9.537
2011	01/01/2010 to 31/12/2010	5.872	2.780	8.652
2012	01/01/2011 to 31/12/2011	5.505	2.828	8.333
2013	01/01/2012 to 31/12/2012	4.165	3.084	7.249
2014	01/01/2013 to 31/12/2013	4.238	2.841	7.080

913 Chairmont, *ERA Hedging costs in the cost of debt*, 13 May 2015, p. 4.

914 Chairmont, *ERA Hedging costs in the cost of debt*, 13 May 2015, p. 6.

915 CEG, *Critique of the AER's approach to transition*, January 2016, p. 65.

Regulatory year	Averaging period	Swap rate (base rate)	DRP	Return on debt
2015	01/01/2014 to 31/12/2014	4.011	2.059	6.069
2016	03/09/2015 to 30/09/2015 (sample only)	3.014	2.236	5.250

Source: CitiPower

The resulting return on debt estimate for 2016 (calculated as a simple average of the return on debt for each of the above regulatory years, which is then annualised) is 7.76 per cent. This is indicative as it is based on an estimate of the prevailing return on debt for 2016 using a sample averaging period and will need to be updated by reference to our actual averaging period for estimating the prevailing return on debt for 2016 for the purposes of making the AER's new distribution determination in substitution for its preliminary determination.

In the event, contrary to our proposal, an optimal hedge form of hybrid transition is applied by the AER, the calculation would need to be amended to include an allowance for swap transaction costs.

The model CP Rate of return illustration[916] attached to this revised regulatory proposal, sets out the estimates for the return on debt for both our proposed immediate transition to the trailing average approach to estimating the return on debt and the optimal hedge form of hybrid transition.

New issue premium

As noted in our regulatory proposal, the third party data series that are used to estimate the return on debt are based on observations in the secondary debt market. These data sources therefore do not reflect any premium required for new debt issues.

Our regulatory proposal and the supporting expert report from CEG set out the economic rationale and empirical evidence for a new issue premium. CEG's analysis indicates that the best estimate of the new issue premium that is relevant to a benchmark debt management strategy of issuing 10 year BBB rated debt is 27 basis points.[917]

In the AER's preliminary determination, the AER states that 'the empirical evidence on the new issue premium is inconclusive' and that 'there does not appear to be a consensus among experts on how the new issue premium should be measured'.[918] The AER also states that it has some specific concerns with CEG's methodology.

We do not agree with the concerns expressed by the AER in relation to new issue premium based on CEG review of AER's analysis submitted with this revised regulatory proposal.[919]

We consider that CEG's analysis provides clear evidence of a positive and significant new issue premium. At a minimum, this evidence demonstrates that making no allowance for a new issue premium (as we do) is highly conservative, in the sense that it is likely to lead to under-estimation of the efficient financing costs of a BEE.

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916 CP PUBLIC RRP MOD 1.42- *CP Rate of Return Illustration*.xlsx

917 CEG, *New Issue Premium*, October 2014, p. 54.

918 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-206.

919 CEG, *Critique of AER analysis of New Issue Premium*, December 2015.

10.5.4 Our revised regulatory proposal

For reasons set out above, it is our primary position that the trailing average approach to estimating the return on debt should be implemented immediately, with no transition. This is necessary to ensure that the return on debt allowance reflects the efficient financing costs of a BEE – i.e. the cost of financing a staggered portfolio of fixed-rate debt.

Alternatively, even if the AER's view is correct that it is necessary to have regard to the financing practices of a regulated BEE in response to previous regulatory methodologies and settings, the appropriate approach would be to adopt an optimal hedge form of hybrid transition with hedging of one third of the base rate and no transition of the DRP component of the return on debt.

That is, if the AER is correct that efficient financing practice involves some degree of hedging of the base rate, it is then necessary to consider to what degree hedging would be efficient, and a transition can only apply to the base rate component to the extent that the BEE used hedging to match the previous on-the-day approach to setting the allowed return on debt. The evidence demonstrates that the efficient level of hedging under the previous on-the-day approach was around one third. An allowance based on a hybrid form of transition which assumes 100 per cent hedging of the base rate is not supported by the evidence and would result in a mismatch between the efficient financing costs of the BEE and the allowed return on debt.

Indicative estimates for the first year of the regulatory control period based on these two alternative approaches are calculated in the model CP Rate of return illustration[920], attached to this revised regulatory proposal, and set out below. These estimates are based on:

- a 10-year benchmark term of debt and credit rating of BBB to BBB+;
- the average yields from the RBA and Bloomberg curves (except for the prevailing return on debt in 2016, which is based on the weighted yields from the RBA, BVAL and Reuters curves) extrapolated in accordance with the AER's methodology (where necessary); and
- for the prevailing return on debt in 2016, the 20 business days ending 30 September 2015.

Table 10.13 Indicative return on debt for the first year of the regulatory control period

Transition method	Return on debt for first year
No transition (immediate application of trailing average method)	7.76%
Optimal hedge form of Hybrid transition, with 1/3 optimal hedging ratio	6.89%

Source: CitiPower

In light of the temporal constraints for the preparation of our response to the AER's preliminary determination, the fact that our accepted equity averaging period and 2016 debt averaging period have not yet occurred, and the uncertainty as to the timing of the Tribunal decision in the NSW and ACT merits reviews (which decision will impact on many of the issues dealt with in this chapter), we have used as a placeholder in the models submitted with this revised regulatory proposal the allowed rate of return estimates used for the purposes of the AER's preliminary determination. While we have used these estimates for convenience, we propose that, for the purposes of making the new distribution determination in substitution for the preliminary determination, the return on debt for 2016 be estimated in accordance with the methodology outlined in this revised regulatory proposal by reference to our accepted debt averaging period for that regulatory year. Consistent with the

920 CP PUBLIC RRP MOD 1.42- *CP Rate of Return Illustration*.xlsx

methodology outlined, we propose that the return on debt then be updated annually for the second and each subsequent regulatory year of the 2016–2020 regulatory control period in accordance with the annual debt update process outlined in the AER's preliminary determination.

To assist the AER in making the new distribution determination in substitution for its preliminary determination, after the Tribunal decision in the NSW and ACT merits reviews is published and our actual averaging period has passed, we intend to submit to the AER a model that sets out the return on debt estimates determined by reference to our proposal and our actual averaging period.

Our revised regulatory proposal represents a departure from the methods for estimating the return on debt set out in the RoR Guideline. Our reasons for departure are set out in this chapter.

10.6 Allowed rate of return

10.6.1 Initial regulatory proposal

In our regulatory proposal, we noted our agreement with many parts of the RoR Guideline,[921] which included the gearing ratio of 60 per cent (i.e. 60:40 debt to equity).[922] Using that gearing ratio and based on the 20 days to 30 January 2015, the RoR proposed in our regulatory proposal was 7.20 per cent.[923]

10.6.2 AER's preliminary determination

In the AER's preliminary determination, the AER:

- agreed with our adoption of a 60 per cent gearing ratio consistent with the RoR Guideline;[924] and
- AER calculated a weighted average of its return on equity and return on debt estimates (**WACC**) determined on a nominal vanilla basis which it considered consistent with its estimate of the value of imputation credits.

The AER therefore rejected our proposed RoR and instead determined an allowed rate of return of 6.02 per cent (nominal vanilla), which in the AER's view achieves the ARORO.[925]

10.6.3 Our response to the AER's preliminary determination

We agree with the AER's decision to accept our proposed gearing ratio of 60:40 debt to equity. However, we disagree with the AER's decision on the allowed rate of return for the 2016–2020 regulatory control period. The return on equity and return on debt ought to be estimated as we have outlined above.

By way of an indicative value, based on the last 20 business days in September 2015, our proposed allowed rate of return would be 8.61 per cent for 2016. However, this allowed rate of return would need to be updated once our actual equity and 2015 debt averaging periods have passed, and updated annually for the second and each subsequent regulatory year for the updated return on debt.

In light of the temporal constraints for the preparation of our response to the AER's preliminary determination, the fact that our accepted equity averaging period and 2016 debt average period have not yet occurred, and the uncertainty as to the timing of the Tribunal decision in the NSW and ACT merits reviews (which decision will impact on many of the issues dealt with in this chapter), we have used as a placeholder in the models submitted

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921 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 193.

922 CitiPower, CP PUBLIC MOD 1.10 - *CP 2016-20 PTRM*.

923 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 240.

924 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-11.

925 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-10.

with this revised regulatory proposal the allowed rate of return estimates used for the purposes of the AER's preliminary determination. While we have used these estimates for convenience, we propose that, for the purposes of making the new distribution determination in substitution for the preliminary determination, the allowed rate of return for 2016 be estimated in accordance with the methodology outlined in this revised regulatory proposal after our accepted equity averaging period and 2016 debt averaging period have passed. Consistent with our proposed return on debt methodology, we propose that the allowed rate of return then be updated annually for the second and each subsequent regulatory year of the 2016–20 regulatory control period for the updated return on debt.

10.6.4 Our revised regulatory proposal

We maintain our proposed gearing ratio (accepted by the AER) of 60:40 debt to equity. We propose that the return on equity and return on debt be estimated as outlined above.

By way of an indicative value, based on the last 20 business days in September 2015, our proposed allowed rate of return would be 8.61 per cent for 2016. However, this allowed rate of return needs to be updated once our actual equity averaging period and 2016 debt averaging period have passed, and updated annually for the second and each subsequent regulatory year for the updated return on debt.

While, as discussed above, we have used as a placeholder in the models submitted with this revised regulatory proposal the allowed rate of return set out in the AER's preliminary determination, we propose that the allowed rate of return for 2016 be estimated in accordance with the methodology outlined above after our accepted equity averaging period and 2016 debt averaging period have passed. Consistent with our proposed return on debt methodology, we then propose that the allowed rate of return then be updated annually for the second and each subsequent regulatory year of the 2016–2020 regulatory control period for the updated return on debt.

To assist the AER in making a new distribution determination in substitution for its preliminary determination, after the Tribunal decision in the NSW and ACT merits reviews is published and our actual averaging period has passed, we intend to submit to the AER a model that sets out the rate of return estimates determined by reference to our actual equity averaging period and 2016 debt averaging period have passed.

10.7 Gamma

10.7.1 Initial regulatory proposal

In Appendix J to our regulatory proposal, we proposed to calculate gamma in the conventional manner; that is, we calculated gamma by multiplying the distribution rate and the value of imputation credits to investors who receive them (referred to as Greek letter, θ, or theta).[926] Specifically, we proposed a distribution rate of 0.7 and a theta estimate of 0.35, resulting in a gamma of 0.25.[927]

The distribution rate of 0.7 adopted in our regulatory proposal was consistent with the RoR Guideline, past regulatory practice and previous decisions of the Tribunal.[928] Conversely, the proposed estimate for theta in our regulatory proposal represented a reasoned departure from the RoR Guideline and is consistent with, and substantiated by, the expert advice of Professor Gray (SFG Consulting).[929] We concluded that:[930]

926 CitiPower, Regulatory proposal 2016–2020, April 2015, p. 241.

927 CitiPower, Regulatory proposal 2016–2020, April 2015, p. 241.

928 CitiPower, Regulatory proposal 2016–2020, April 2015, p. 241.

929 CitiPower, Regulatory proposal 2016–2020, April 2015, Appendix J, p. 4.

930 CitiPower, Regulatory proposal 2016–2020, April 2015, Appendix J, p. 4.

- theta is the value of distributed imputation credits to investors, consistent with the requirements of the Rules, and is estimated using the best available market value study. Such studies indicate the value of imputation credits to investors, as reflected in share price movements; and
- at the time of our regulatory proposal, the best estimate of theta from market value studies was 0.35.

Our approach ensured that the adjustment for the value of imputation credits in the cost of corporate income tax building block properly reflects the actual value of imputation credits to investors in the BEE, rather than the notional face value or potential value of imputation credits. As such, the overall return received by investors (taking into account the value they ascribe to distributed imputation credits) is sufficient to promote efficient investment in, and the efficient operation and use of, electricity services in the long term interest of consumers and will better contribute to the achievement of the NEO.

10.7.2 AER's preliminary determination

In the AER's preliminary determination, the AER did not accept our proposed value of imputation credits of 0.25.[931] Instead, the AER adopted an estimate of 0.4.[932] In the AER's view, the available evidence and advice suggested that a 'reasonable estimate' of the value of imputation credits fell within the range of 0.3 to 0.5, from which the point estimate of 0.4 was ultimately chosen.[933]

The AER's preliminary determination on the value of imputation credits departed from the RoR Guideline in several respects, based on the following reasoning:

- gamma should represent the proportion of company tax that is returned to investors through the utilisation of imputation credits and this is the value of imputation credits to investors;[934]
- gamma is calculated by multiplying the 'distribution rate' by the 'utilisation rate';[935]
  - the distribution rate is the proportion of imputation credits generated that is distributed to investors; and
  - the utilisation rate is the before-personal-tax and before-personal-costs utilisation value to investors in the market per dollar of imputation credits distributed.[936] That is, when calculating the utilisation rate, any reason why resident investors may value imputation credits at less than their nominal face value, including personal tax and personal costs, are to be excluded from consideration;
- in determining the distribution rate, the AER may have regard to evidence from all equity and/or listed equity only;[937]
- the distribution rate is approximately 0.7 for all equity and 0.77 for listed equity only;[938]
- there is no single accepted approach to estimating the utilisation rate and a range of evidence relevant to the utilisation rate;[939]

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931 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-7.

932 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-7.

933 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-8.

934 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-52.

935 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-16.

936 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-16.

937 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-18.

938 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-19.

939 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-17.

- the equity ownership approach indicates that the utilisation rate is between 0.56 and 0.68 for all equity and between 0.38 and 0.55 for listed equity only;[940]
- the credit redemption rate from tax statistics is 0.45;[941]
- market value studies indicate a range for the value of theta from 0 to 1;[942]
- the estimate of theta should primarily reflect an estimate of the utilisation rate from the 'equity ownership approach', placing less reliance on evidence of the credit redemption rate from tax statistics, and lesser weight still on market value studies;[943]
- the overlap in the range of gamma values calculated by the AER based on the equity ownership approach for each of an 'all equity' distribution rate and theta, and a 'listed equity' distribution rate and theta suggests a value for gamma of between 0.40 and 0.42;[944] and
- evidence from tax statistics and the SFG market value study suggests a value for gamma lower than 0.40, which suggests that a value for gamma at the lower end of the range suggested by 'the overlap of evidence from the equity ownership approach' (that is, 0.4) should be adopted.[945]

10.7.3 Our response to the AER's preliminary determination

Introduction

In the AER's preliminary determination, the AER adopts a similar approach to estimating gamma as in recent decisions. This involves:

1. Conceptualising gamma as the before-personal-tax and before-personal-costs value of imputation credits. In line with this conceptual approach, the AER estimates gamma as the product of the distribution rate and the utilisation value to investors in the market per dollar of imputation credits distributed (referred to as the 'utilisation rate').[946]
2. Deriving estimates of the distribution rate and theta for each of 'all equity' and 'listed equity'.[947] For theta, the AER derives a number of different estimates, based on three different estimation methods:
   (i) the equity ownership approach, which uses ABS data to estimate the proportion of equity in Australian companies held by domestic investors;
   (ii) tax statistics, which indicate the proportion of distributed imputation credits that are redeemed by investors; and
   (iii) market value studies.
3. Calculating gamma values based on its pairing of:
   (i) its estimate of the distribution rate for all equity with its estimates of theta for all equity based on the equity ownership approach and tax statistics; and

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940 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-19.
941 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-19.
942 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-19.
943 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 4-19 to 4-20.
944 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-19.
945 AER, *Preliminary decision, CitiPower distribution determination 2016–20, October 2015*, p. 4-19.
946 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-16.
947 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 4-18 to 4-19.

(ii) its estimate of the distribution rate for listed equity with its estimates of theta for listed equity based on the equity ownership approach and market value studies.

4. Determining a range for gamma based on 'the overlap of evidence from the equity ownership' approach (i.e. the overlap between the gamma ranges calculated by the AER based on the equity ownership approach for each of 'all equity' and 'listed equity').[948] The AER considered that the overlap of the evidence from the equity ownership approach suggests a value for gamma between 0.40 and 0.42.
5. Selecting a point within the range defined by step 4 by reference to evidence from tax statistics and market value studies. The AER observed that both tax statistics and SFG's market value study suggest a value for gamma lower than 0.4. On this basis, the AER adopted a value for gamma at the lower end of the range suggested by the overlap of the evidence from the equity ownership approach (that is, 0.4).[949]

As discussed below, the AER has made errors at each of these steps in its reasoning.

For reasons set out below, we maintain our position that the best estimate of gamma is 0.25. This estimate reflects a proper interpretation of the Rules and the best empirical evidence in relation to the value of imputation credits.

The AER's conceptual approach to estimating gamma

The AER's conceptual approach to estimating gamma appears to have evolved since it published the RoR Guideline.

In the RoR Guideline, the AER approached gamma as a measure of the proportion of imputation credits that can be utilised. The AER defined theta as 'the extent to which investors can use the imputation credits they receive to reduce their tax (or receive a refund)'.[950] Thus, in the RoR Guideline, the AER appeared to treat gamma as a measure of the utilisation, or eligibility to utilise / potential for utilisation of imputation credits.

In the AER's preliminary determination, the AER seeks to estimate gamma as the 'before-personal-tax and before-personal-costs' value of imputation credits. The AER appears to acknowledge in its preliminary determination that gamma is a measure of the value of imputation credits to investors[951], not simply their utilisation, or potential for utilisation. However, the AER states that this value must be measured on a 'before-personal-tax and before-personal-costs basis'.[952] Consistent with this, the AER estimates the utilisation rate (theta) as 'the before-personal-tax and before-personal-costs utilisation value to investors in the market per dollar of imputation credits distributed'.[953]

Thus, between the Guideline and the AER's preliminary determination, the AER appears to have shifted from treating gamma as a 'utilisation' (or potential utilisation / eligibility for utilisation) concept to treating it as a 'value' concept.

However, because the AER seeks to estimate value on a before-personal-tax and before-personal-costs basis, its approach is in fact unchanged. Since the AER ignores the effect of any factors which might reduce the value of imputation credits that are redeemed, its approach to estimating value is effectively equivalent to estimating the rate of imputation credit utilisation (or potential for utilisation) or to assuming that those factors have no

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948 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-19.

949 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-19.

950 AER, *Better Regulation, Explanatory Statement, Rate of Return Guideline*, December 2013, p. 159.

951 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-16.

952 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-16.

953 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-33.

affect—which it has not tested nor has any evidence to support. The AER explains this in its preliminary determination as follows:[954]

> *In the Guideline, we also defined the utilisation rate as the extent to which investors can use the imputation credits they receive to reduce their tax (or receive a refund). In this decision, consistent with Handley's advice, we consider the utilisation rate is the utilisation value to investors in the market per dollar of imputation credits distributed. However, we consider that our views in the Guideline and in this decision are broadly equivalent; that is, our definition of the utilisation rate in this preliminary decision still reflects the extent to which investors in the market can use the imputation credits they receive. This is because, as discussed above and in sections A.5, A.7 and A.8.1, to be consistent with the Officer framework (and therefore the building block framework in the NER/NGR) the utilisation rate should reflect the before-personal-tax and before-personal-costs value of imputation credits to investors. On a before-personal-tax and before-personal-costs basis, an investor that is eligible to fully utilise imputation credits should value each dollar of imputation credits received at one dollar (that is, have a utilisation rate of 1).*

In effect, the AER continues to interpret gamma as a measure of the utilisation of imputation credits, or a measure of investors' eligibility to utilise those credits.

As explained in our regulatory proposal, this approach is contrary to the requirements of the Rules and represents a significant departure from conventional and previous regulatory practice.

We consider that it is clear from the language of clause 6.5.3 of the Rules that the AER is required to estimate the value of imputation credits, not the utilisation of imputation credits, or a measure of investors' eligibility to utilise those credits. Clause 6.5.3 refers to the 'value of imputation credits', not utilisation. Indeed, the Rules were recently amended to change the definition of gamma from 'the assumed utilisation of imputation credits' to 'the value of imputation credits'.

Further, a value-based approach to estimating gamma (and theta) will best promote the NEO, as it provides for overall returns which promote efficient investment. As noted by Professor Gray:[955]

> *Under the building block approach, the regulator makes an estimate of gamma and then reduces the return that is available to investors from dividends and capital gains from the firm accordingly. In my view, it is clear that this is consistent with a value interpretation. If the value of foregone dividends and capital gains is greater than the value of received imputation credits, the investors will be left under-compensated, and vice versa.*

If gamma is treated as merely a measure of utilisation, or if the value of imputation credits is assessed before personal costs and taxation (i.e. ignoring these costs to investors), the overall return to equity-holders will be less than what is required to promote efficient investment. Quite simply, there will be certain costs incurred by investors – such as transactions costs involved in redeeming credits – which are not accounted for.

The value of imputation credits to investors will necessarily reflect (and will be net of) any transactions costs or other personal costs incurred in redeeming credits. Such costs cannot simply be assumed away. If such costs are assumed away, then the resulting estimate of theta (and therefore gamma) will overstate the true value of imputation credits to investors.

Therefore, we maintain our position that the estimate of theta must simply reflect the value of imputation credits to investors. It would be an error to seek to estimate theta as a hypothetical before-personal-tax and before-personal-costs value.

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[954] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-53.

[955] SFG, *Estimating gamma for regulatory purposes*, February 2015 at [12].

Estimates of the distribution rate

The appropriate measure of the distribution rate

The AER refers to a distribution rate for 'all equity' and for 'listed equity' only. The 'all equity' figure is based on analysis of the cumulative payout ratio across all Australian companies, using ATO data. The 'listed equity' figure is also based on ATO data, but with an allocation of total tax paid between public and private companies.[956]

We consider that it is neither necessary nor appropriate to separately identify a distribution rate for a limited set of listed businesses only. This is because the distribution rate for all equity is likely to be a reasonable proxy for that of the BEE. On the other hand, for reasons discussed below, the distribution rate for a limited set of listed businesses is likely to be a poor proxy for that of the BEE.

Whereas the AER's definition of the BEE is assumed to operate solely within Australia[957], the distribution rate for listed equity is likely to be skewed by the practices of multinational firms with significant foreign earnings. Almost two thirds of the value of listed entities comprises the top 20 firms, which tend to be large multinational firms with significant foreign earnings. The presence of material foreign earnings can have a significant impact on a firm’s distribution rate because imputation credits are only created when tax is paid on Australian earnings, but may be distributed with any dividend (whether distributing Australian earnings or foreign earnings). This means that for a given dividend payout ratio (i.e., the proportion of profits that are distributed as dividends), the imputation credit distribution rate will be higher (as a proportion of total credits created) for an entity with more foreign profits.

This is illustrated by way of example by Professor Gray.[958] Professor Gray compares two hypothetical firms with the same dividend payout ratio (i.e., the proportion of profits that are distributed as dividends), but with different levels of foreign earnings. His example shows that the existence of foreign earnings leads to a materially higher distribution rate, even where the dividend payout ratio is the same.

The effect of foreign earnings on the distribution rate can also be seen in the empirical estimates of the distribution rate for different company types. As may be expected, the distribution rate for top-20 ASX listed companies (many of which will have material foreign earnings) is significantly higher than the average distribution rate across all companies (0.84 compared to 0.68). When top-20 ASX listed companies are removed from the public company set, the distribution rate for public companies falls to around the rate across all companies (0.69).

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956 NERA, *Estimating Distribution and Redemption Rates from Taxation Statistics*, March 2015, section 3.3.

957 The AER's definition of the benchmark efficient entity is a pure play, regulated energy network business *operating within Australia*: AER, *Better Regulation, Rate of Return Guideline*, p. 7; AER, *Better Regulation, Explanatory Statement, Rate of Return Guideline*, December 2013, pp. 32 to 35, see in particular the discussion of 'Operating within Australia' (at page 35).

958 SFG, *Estimating gamma for regulatory purposes*, 6 February 2015, p. 45.

Table 10.14 Distribution rate by company type

Firm type	Distribution rate
Top-20 ASX listed	0.840
Public but not top-20 ASX listed	0.693
All publicly listed	0.755
Private	0.505
All	0.676

Source: NERA, *Estimating Distribution and Redemption Rates from Taxation Statistics*, March 2015, p. 23.

Given that the BEE, by definition is a business with no foreign profits, it would be inappropriate to use a measure of the distribution rate that is skewed by businesses with material foreign earnings.

In the AER's preliminary determination, the AER suggests that, although the listed equity distribution rate may be unrepresentative of the distribution rate for the BEE, it may nonetheless be necessary to use a listed equity distribution rate for 'internal consistency'.[959] The AER considers that where an estimate of theta is based on the value of imputation credits to a particular set of investors, the distribution rate that is combined with that theta estimate must be for the same set of investors. On this reasoning, the AER considers that if an estimate of theta based on listed equity data is used, this must be combined with a listed equity distribution rate.

For reasons discussed under the heading 'Pairing of estimates for 'all equity' and 'listed equity' below, we do not agree that estimates of theta based on listed equity data must be paired with a listed equity distribution rate. The distribution rate and theta are separate parameters and need not be estimated using the same dataset. Whereas the distribution rate is a measure of the credit distribution practices of the BEE, theta is a measure of the value of credits to investors (or potential investors). In each case it must be considered which approach will provide the best estimate for the BEE, and there is no reason why this ought to be the same across all parameters. For reasons discussed above, the distribution rate for the BEE will be best proxied by the distribution rate across all companies. On the other hand, for reasons set out below, to the extent that the rate of equity ownership is relevant to theta, the most informative measure is that for listed equity. Put another way, the BEE is an entity with solely Australian earnings, but is likely to be foreign owned as any listed entity.

This position is supported by Frontier Economics in its expert report accompanying this revised regulatory proposal.[960] Frontier Economics notes that whether the BEE is defined narrowly (as the firms that the AER regulates) or more broadly, for the purposes of estimating the distribution rate it would not include firms that have foreign-sourced profits to assist in the distribution of imputation credits. Thus, the distribution rate should not be estimated with reference to the top 20 ASX-listed firms, or with reference to any estimate that is materially affected by the top 20 firms. For this reason, Frontier Economics recommends excluding the influence of the top 20 firms from any estimate of the distribution rate for the BEE. Frontier Economics notes that but for the top 20 listed firms, the distribution rate estimate for listed equity is 70 per cent, which is in line with the distribution rate for all equity.

[959] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-86.

[960] Frontier Economics, *The appropriate use of tax statistics when estimating gamma*, January 2016, p. 15.

Distribution rate for all equity

We agree with the AER’s conclusion in its AER's preliminary determination that the best estimate of the distribution rate across all equity is 0.7.

Recent analysis by NERA (referred to in the table above) indicates that the distribution rate across all equity is now slightly below 0.7, at around 0.68.[961] Therefore 0.7 represents a reasonable and conservative estimate.

Estimates of the value of distributed credits (theta)

Types of evidence relied on by the AER to estimate theta

There are three types of evidence referred to by the AER in relation to theta. These are, in order of weight given by the AER:

- equity ownership rates (i.e. the share of Australian equity held by domestic investors);
- redemption rates from tax statistics; and
- market value studies.

This section will address the relevance of each of the forms of evidence relied on by the AER in its AER's preliminary determination, to the task of estimating the value of imputation credits to investors.

Equity ownership rates

The AER continues to rely on the equity ownership approach as direct evidence of the value of distributed imputation credits. The AER states that its estimate of the value of distributed imputation credits 'primarily reflects' the evidence from the equity ownership approach.[962]

The AER’s estimates of the equity ownership rate provide a binding constraint on its estimates of theta and gamma. As noted above, the AER adopts a range for gamma based on 'the overlap of evidence from the equity ownership' approach.[963] Other evidence is then only used to determine where in this range the AER’s point estimate of gamma should lie. Since other evidence indicates a gamma that is below the AER’s range from the equity ownership approach, this other evidence is effectively disregarded by the AER. It is only the AER’s estimates of the equity ownership rate that are consistent with its estimates of theta and gamma.

In relying on equity ownership rates as direct evidence of the value of distributed imputation credits, the AER at least implicitly assumes that:

- all domestic investors are eligible to utilise imputation credits, while foreign investors are not (**Assumption 1**); and
- eligible investors (i.e. domestic investors) value imputation credits at their full face value because each dollar of imputation credits received can be fully returned to them in the form of a reduction in tax payable (**Assumption 2**).

Both of these assumptions are incorrect.

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961 NERA, *Estimating Distribution and Redemption Rates from Taxation Statistics*, March 2015, p. 23.

962 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-17.

963 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-19

Assumption 1 is known to be incorrect due to certain tax rules which prevent redemption of credits by domestic investors in some circumstances. In particular, not all domestic investors are eligible to utilise imputation credits, for example due to the 45-day holding rule[964] or because they are in a tax loss position.

The AER acknowledges the 45-day rule but considers that it can be assumed to have a negligible effect.[965] However, the analysis underpinning this conclusion is based on data that is known to be unreliable. The AER relies on analysis of the ATO dividend data presented in an expert report by Dr Neville Hathaway dated September 2013.[966] However that report explained that there 'appears to be a big problem with the data' in that a large amount of credits are not accounted for in the ATO dividend data – i.e. there is $87.5 billion in franking credits that appear in the ATO tax paid and franking account balance (FAB) data, but which are missing from the dividend data. Dr Hathaway expresses more confidence in the ATO tax paid and FAB data, and says that it is likely to be the ATO dividend data where the problem lies.[967] The AER analysis on the effect of the 45-day rule appears to be entirely based on the ATO dividend data, despite Dr Hathaway's warnings regarding the reliability of this data. The AER does not appear to take into account the point made by Dr Hathaway, that the ATO dividend data appears to grossly underestimate the amount of imputation credits distributed, or to assess whether this data is reliable enough to analyse the impact of the 45-day rule.[968]

The ATO tax paid and FAB data (which Dr Hathaway considers to be more reliable) indicate that the redemption rate for imputation credits is materially below the domestic equity ownership rate across all equity, suggesting that equity ownership figures do overstate the level of actual utilisation. The AER (correctly) observes that the current redemption rate is 0.45, which is significantly below the domestic equity ownership rate across all equity (currently 0.6).[969] This indicates that factors such as the 45-day rule or tax losses are in fact preventing or deterring the redemption of imputation credits by some domestic investors.

As for Assumption 2 above, our regulatory proposal identified a number of reasons why even eligible investors will not value imputation credits at their full face value. These include transaction costs associated with the redemption of imputation credits and portfolio effects (discussed below).

Given that neither of these assumptions hold, equity ownership rates cannot be used as direct evidence of the value of distributed imputation credits. Equity ownership rates will only indicate the maximum set of investors who may be eligible to redeem imputation credits and who may therefore place some value on imputation credits. Certainly theta cannot be higher than the domestic equity ownership rate, since foreign investors cannot place any value on imputation credits and it would be irrational to place more value on a redeemed credit than

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964 Although the 'qualified persons' rules, and the 45-day holding rule within those rules, were repealed from the *Income Tax Assessment Act 1936* (Cth) (**ITAA36**) in 2002, they still have ongoing application as a result of being imported into the imputation rules by section 207-145(1)(a) of the *Income Tax Assessment Act 1997* (Cth) (**ITAA97**). Section 207-145(1)(a) of the ITAA97 provides that the amount of the franking credit on a distribution is not included in the assessable income of an entity or allowed as a credit where the entity is not a 'qualified person' in relation to the distribution. A 'qualified person' for the purposes of this 'section' (per section 160APHO(2)) is, broadly, a taxpayer who has held shares or an interest in shares on which a dividend has been paid, 'at risk' for a continuous period of not less than 45 days. To work out whether the shares are 'at risk', a taxpayer is required to first work out their 'net position', which is determined under the rules contained in the repealed section 160APHJ of the ITAA36.

965 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-72.

966 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-72. Table 4-6 refers to the following report as its data source: Hathaway, *Imputation Credit Redemption ATO data 1988-2011 – Where have all the credits gone?*, September 2013. It appears that the figures in Table 4-6 is drawn from Figure 4 of Hathaway's report, which (as explained in paragraphs [51] and [52] of that report) relies on the ATO dividend data.

967 Hathaway, *Imputation Credit Redemption ATO data 1988-2011 – Where have all the credits gone?,* September 2013 at [50].

968 The figures in Table 4-6 on page 4-71 of the preliminary determination appear to be taken from Figure 4 on page 18 of Hathaway's report, which is based on the ATO dividend data.

969 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-19.

the dollar value of tax that can be offset by it. However the domestic equity ownership rate cannot be used as direct evidence of the value of imputation credits, because it does not account for the fact that:

- some domestic investors may be ineligible to redeem imputation credits; and
- even eligible investors will not value imputation credits at their full face value.

Therefore the AER has erred in concluding that equity ownership rates are direct evidence of the value of imputation credits (or evidence from which a value can be inferred) and in giving these measures the primary role in the determination of a point estimate for theta.

Tax statistics

The AER also appears to rely on redemption rates from tax statistics as direct evidence of the value of distributed imputation credits. The AER states that it has placed 'some reliance' on tax statistics in estimating theta, but less reliance than is placed on equity ownership rates.[970]

Redemption rates from tax statistics will be closer to the true value of imputation credits than domestic equity ownership rates. This is because redemption rates account for certain factors impacting on the value of imputation credits which are not accounted for in the domestic equity ownership rate – for example, redemption rates will reflect the fact that some domestic investors are not eligible to redeem credits due to the 45-day holding rule, and that some investors face costs and other barriers that deter them from utilising imputation credits.

However redemption rates from tax statistics also cannot be used as direct evidence of the value of distributed imputation credits, because redemption rates do not take into account the fact that investors may value redeemed credits at less than their full face value. As noted above, our regulatory proposal identified a number of reasons why investors will not value imputation credits at their full face value, including:

- *Transaction costs.* Transaction costs associated with the redemption of credits may include requirements to keep records and follow administrative processes. This can be contrasted with realisation of cash dividends, which are paid directly into bank accounts. The transaction costs associated with redemption of imputation credits will tend to reduce their value to investors (meaning that the value of credits redeemed will be less than their face value) and may also dissuade some investors from redeeming credits (thus reducing the redemption rate);
- *Time value of money*. There will typically be a significant delay (which can be years) between credit distribution and the investor obtaining a tax credit. This may be a period of several years in some cases, for example where credits are distributed through other companies or trusts, or where the ultimate investor is initially in a tax loss position. Over this period, the value of the imputation credit to the investor may be expected to diminish, due to the time value of money; and
- *Portfolio effects*. Portfolio effects refer to the impact of shifting the investor's portfolio away from the optimal construction (including overseas investments) in order to take advantage of imputation. An investor who would otherwise invest overseas (to get a better return from the overall portfolio) might choose instead to make that investment in Australia to obtain the benefit of an imputation credit. This reallocation of portfolio investment would tend to continue with the relevant imputation credit having less and less marginal value until an equilibrium is reached with the credit having no additional value: that is, on average, the value of the imputation credits will be less than the face value. To the extent that an investor reduces the value of their overall portfolio simply to increase the extent to which they can redeem imputation credits,

[970] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-25.

this lost value will be reflected in a lower valuation of the imputation credits. These portfolio effects are further explained in the expert report of Professor Stephen Gray which accompanied our regulatory proposal.[971]

It has been previously accepted by the Tribunal that redemption rates from tax statistics can only indicate the upper bound for theta.[972] Theta clearly cannot be higher than the proportion of credits that are redeemed by investors, since credits that will never be redeemed have no value. However theta may be (and for reasons referred to above, is likely to be) less than the redemption rate.

Therefore the AER has erred in giving redemption rates a direct role in the determination of a point estimate for theta, and in failing to recognise that redemption rates are an upper bound for theta.

Market value studies

The AER places least weight on market value studies, as it considers that these studies have a number of limitations, including:[973]

- these studies can produce nonsensical estimates of the utilisation rate – that is, greater than one or less than zero;
- these studies can be data intensive and employ complex and sometimes problematic estimation methodologies;
- the results of these studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the utilisation rate;
- the results of these studies might not be reflective of the value of imputation credits to investors in the market as a whole; and
- it is only the value of the combined package of dividends and imputation credits that can be observed using dividend drop-off studies, and there is no consensus on how to separate the value of dividends from the value of imputation credits (the 'allocation problem').

In effect, the AER is raising two questions in relation to market value studies:

- Are they measuring the right thing? (reflected in the third point above)
- How well are they measuring it? (reflected in the other four points)

(A) *Are market value studies measuring the right thing?*

The first concern flows from the AER’s conceptual definition of theta, which seeks to exclude the effects of personal taxes and personal costs. Since market values will reflect the impact of personal costs and taxation, the AER considers that a market value approach may not be compatible with its revised definition of theta.

As noted above, we do not agree with the AER’s revised definition of theta (i.e. the qualified version which ignores the effects of personal costs and taxation). As explained in our regulatory proposal, theta must reflect the value of distributed imputation credits to investors, which will necessarily reflect (and will be net of) any transaction costs or other personal costs incurred in redeeming credits.

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971 SFG, *Estimating gamma for regulatory purposes*, February 2015.

972 *Application by Energex (No 2)* [2010] ACompT 7 at [91].

973 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-29.

If the conventional definition of theta is adopted – i.e. defining theta as the value of distributed imputation credits to investors – then use of market value studies is entirely compatible with this definition. Market value studies will reflect the value of imputation credits to investors, as reflected in market prices for traded securities.

Indeed, of the three approaches identified by the AER to estimate theta, an approach based on market value studies is the only approach that is entirely compatible with a definition of theta that is consistent with the Rules and the NEO. As discussed above, both equity ownership rates and redemption rates from tax statistics will overstate the true value of theta, since they will not reflect certain factors which affect the value of imputation credits to investors.

Use of market value studies – and more generally, the adoption of a market value measure – is also consistent with how other rate of return parameters are estimated.[974] Other rate of return parameters such as the MRP and DRP are estimated based on the return required by investors as reflected in market prices. The market value measures of these parameters are not adjusted to account for personal costs or other factors which may be reflected in market prices.

In any event, even if the AER's definition of theta were to be adopted, there is a relatively simple adjustment that can be made to estimates from market value studies to address this concern. As explained by Associate Professor Handley, this involves 'grossing up' the theta estimate from a market value study to reflect the effect of personal costs. If this adjustment were to be made to the estimate from Professor Gray's dividend drop-off study, it would result in a small increase in the theta estimate, from 0.35 to 0.4.[975] (For clarity, we do not agree with this adjustment, because the AER's conceptual definition of theta is clearly wrong. However, if the AER's definition was to be adopted, then this does not require wholesale rejection of market value evidence, since an adjustment can be made to account for differences between the AER's definition and the conventional definition.)

(B) *Do market value studies accurately measure that thing?*

The AER lists several methodological concerns with dividend drop-off studies, several of which are not relevant to the particular study relied on by us.

In particular, the AER's concern about 'nonsensical results' clearly does not apply to Professor Gray's dividend drop-off study. Professor Gray's study produces a theta estimate of 0.35, which is an entirely sensible result given that:

- it is within the theoretical bounds for theta (i.e. it is between zero and one);
- it is below the domestic equity ownership rate for both listed equity (0.46) and all equity (0.6). As noted above, the domestic equity ownership rate indicates the maximum set of investors who may be eligible to redeem imputation credits and who may therefore place some value on imputation credits, and therefore it may be expected that the value for theta would be below this figure; and
- it is also below the redemption rate indicated by tax statistics (0.45). Again, this may be expected given that redemption rates will indicate the upper bound for theta and do not capture certain factors affecting value, such as the time value of money, transaction costs and portfolio effects.

Indeed, the result of the SFG study is consistent with the other evidence and a result that is to be expected in light of that evidence.

974 As noted above, the Rules require the rate of return and the value of imputation credits to be measured on a consistent basis (NER, clause 6.5.2(d)(2)).

975 Handley, *Advice on the Value of Imputation Credits*, 29 September 2014, p. 43.

Similarly, the AER's concern about 'problematic estimation methodologies' may apply to some market value studies but does not apply to the particular study relied on by us. The methodology used in Professor Gray's study is the product of a consultative development process involving the AER and several regulated businesses and overseen by the Tribunal in the Energex review. The methodology used in Professor Gray's study was designed specifically to overcome the methodological shortcomings of previous studies (e.g. shortcomings in the methodology employed by Beggs and Skeels (2006), which were identified by the Tribunal in the Energex review). In accepting the conclusions of Professor Gray's study, the Tribunal expressed confidence in those conclusions in light of the careful scrutiny to which the methodology had been subjected, and the way in which it had been designed to overcome shortcomings of previous studies.[976]

Professor Gray notes that the dividend drop-off literature has evolved over time, and that the SFG studies use current state-of-the-art techniques. Professor Gray explains:[977]

> *In relation to dividend drop-off studies, I first note that the dividend drop-off literature has evolved over time, as do all areas of scientific investigation. This evolution has seen the development of different variations of the econometric specification, different variations of regression analysis, and different types of sensitivity and stability analyses. It has also seen material growth in the available data. The SFG studies use the latest available data, and they apply a range of econometric specifications, regression analysis and sensitivity and stability analyses that have been developed in the literature. The SFG estimate of 0.35 is based on this comprehensive analysis. It is not as though the SFG studies use one of the reasonable approaches and other studies use different reasonable approaches. The SFG studies are comprehensive state-of-the-art studies.*

Box 1 below outlines the process by which the methodology used in Professor Gray's study was developed, and the conclusions of the Tribunal in relation to that methodology. In light of this, it cannot be said that Professor Gray's study shares the same methodological issues as previous market value studies. Rather, this study was specifically designed to overcome the shortcomings of previous studies.

Box 1: Key conclusions of the Tribunal in Energex in relation to the SFG methodology

In *Application by Energex Limited (No 2)* [2010] ACompT 7, the Tribunal had before it two market value studies which produced different estimates of theta – a study by Beggs and Skeels (2006) and a study by SFG (2010) which sought to replicate the Beggs and Skeels (2006) methodology. The Tribunal identified shortcomings in the methodology used in both studies and observed that the results of both studies should be treated with caution.

The Tribunal therefore sought a new 'state-of-the-art' dividend drop-off study.[978] To this end, the Tribunal directed that the AER seek a re-estimation by SFG of theta using the dividend drop-off method, but without the constraint that the study replicates the Beggs and Skeels (2006) study. The Tribunal encouraged the AER to seek expert statistical or econometric advice to review the approach prior to the estimation proceeding and to consider any possible enhancements to the dataset. It was said that the new study should employ the approach that is agreed upon by SFG and the AER as best in the circumstances.

The terms of reference for the new study were settled between the AER and the businesses involved in the Energex review (Energex, Ergon and ETSA Utilities), with oversight from the Tribunal. The AER and the businesses also had the opportunity to comment on a draft of the report, and SFG's responses to those comments are incorporated in the final report.

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976 *Application by Energex Limited (Gamma) (No 5)* [2011] ACompT 9 at [22].

977 SFG, *Estimating gamma for regulatory purposes*, February 2015 at [177].

978 *Application by Energex Limited (No 2)* [2010] ACompT 7 at [146] to [147].

In submissions to the Tribunal, the AER raised eight 'compliance' issues with the final SFG (2011) study – these were perceived issues of non-compliance by SFG with the agreed terms of reference. The Tribunal was not concerned by any of these issues and considered that they raised no important or significant questions of principle. The Tribunal concluded that any departures from the agreed terms of reference were justified, or even necessary and observed that calling them 'major compliance issues' was unnecessarily pejorative.[979]

The Tribunal was ultimately satisfied that the procedures used by SFG (2011) to select and filter the data were appropriate and did not give rise to any significant bias in the results obtained from the analysis. It was also not suggested by the AER that the data selection and filtering techniques had given rise to any bias.[980]

In relation to the model specification and estimation procedure, the Tribunal concluded:[981]

> *In respect of the model specification and estimation procedure, the Tribunal is persuaded by SFG's reasoning in reaching its conclusions. Indeed, the careful scrutiny to which SFG's report has been subjected, and SFG's comprehensive response, gives the Tribunal confidence in those conclusions. In that context, the Tribunal notes that in commissioning such a study, it hoped that the results would provide the best possible estimates of theta and gamma from a dividend drop-off study. The terms of reference were developed with the intention of redressing the shortcomings and limitations of earlier studies as far as possible.*

Ultimately, the Tribunal was satisfied that the SFG (2011) study was the best study available at that time for the purposes of estimating gamma in accordance with the Rules.[982] The Tribunal did not accept the submission of the AER that either minor issues in the construction of the database or econometric issues would justify giving the SFG study less weight and earlier studies some weight.

The other two issues referred to by the AER – the allocation problem, and the possibility that the results of these studies might not be reflective of the value of credits to investors in the market as a whole – have previously been considered and addressed by Professor Gray. These issues are again addressed in Professor Gray's most recent report.[983] As noted in our regulatory proposal:

- in relation to whether estimates reflect the value of credits to investors in the market as a whole, and whether there may be some impact on the theta estimate from 'abnormal trading' around ex-dividend day, Professor Gray notes that to the extent this effect is material it would result in the dividend drop-off (and therefore the theta estimate) being higher than it otherwise would be.[984] This is because any increase in trading around ex-dividend day would be driven by a subset of investors who trade shares to capture the dividend and imputation credit and who are therefore likely to value imputation credits highly (i.e. higher than the average investor). These investors tend to buy shares shortly before payout of dividends (which pushes up the share price) and tend to sell shortly after (which pushes down the share price), the overall effect of which is to increase the size of the price drop-off; and

979 *Application by Energex Limited (Gamma) (No 5)* [2011] ACompT 9 at [18].

980 *Application by Energex Limited (Gamma) (No 5)* [2011] ACompT 9 at [19].

981 *Application by Energex Limited (Gamma) (No 5)* [2011] ACompT 9 at [22].

982 *Application by Energex Limited (Gamma) (No 5)* [2011] ACompT 9 at [29].

983 SFG, *Estimating gamma for regulatory purposes*, February 2015 at [185].

984 SFG, *An appropriate regulatory estimate of gamma*, May 2014 at [150] - [153].

- in relation to the allocation issue, Professor Gray notes that empirical evidence provides a very clear and consistent view of the combined value of cash and imputation credits.[985] This evidence indicates that the combined value is one dollar. The relevant evidence includes the recent studies by SFG (2011 and 2013) and Vo et al (2013). Allocation can be made based on this clear evidence as to combined value of the cash/credit package.

In summary, the general set of 'limitations' referred to by the AER do not provide a justification for placing limited weight on the particular market value study relied on by us. Several of the general limitations do not apply to the SFG study that is relied on by us, and the other concerns have been comprehensively addressed by Professor Gray.

The AER's approach to considering market value studies – which involves simply identifying limitations which may apply to these studies in general, without considering whether those limitations apply to the particular study relied on by us – is illogical and unreasonable. Without considering whether the potential limitations it has identified actually apply to the SFG study, the AER cannot reasonably form a view that this study is unreliable or should be given limited weight.

Accordingly, the AER has erred in placing only limited weight on all market value studies in estimating theta. We consider that approach to be incorrect. Market value studies that are methodologically robust – in particular the SFG study – can and should be used as direct evidence of the value of imputation credits.

Market value studies are the only form of evidence which can provide the basis for a point estimate of theta, rather than just an upper bound.

<u>Estimates relied on by the AER</u>

Range of estimates for the equity ownership rate

The AER concludes that a reasonable estimate of the equity ownership rate is between:[986]

- 0.56 and 0.68, if all equity is considered; and
- 0.38 and 0.55, if only listed equity is considered.

The AER then combines these ranges with its estimates of the distribution rate to derive corresponding ranges for gamma. The AER's gamma estimate is taken from the point of overlap between these two ranges.

We have three concerns with the AER's approach to the construction of ranges for the equity ownership rate:

- first, the AER has erroneously treated equity ownership rates as direct evidence of theta. For reasons discussed above, equity ownership rates provide at best an upper bound for theta;
- secondly, the AER has used estimates of the 'listed equity' and 'all equity' equity ownership rate, without proper consideration of which measure is likely to be most appropriate for the BEE; and
- thirdly, the AER has inappropriately taken a range for the equity ownership rate over a long period, rather than assessing the current equity ownership rate.

The first issue is addressed under the heading 'Equity ownership rates' above. The second and third issues are addressed below.

(A) *Listed equity and all equity measures*

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985 SFG, *An appropriate regulatory estimate of gamma*, May 2014 at [158] - [163].

986 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-97.

Given that measures of the equity ownership rate are available both for all equity and listed equity only, it is necessary to consider which of these measures is likely to be most appropriate in estimating the value of imputation credits to investors in the BEE.

To the extent that equity ownership rates are relevant (i.e. as an absolute upper bound on theta), the relevant measure is the listed equity measure. This is because the equity ownership rate for the BEE is best proxied by the listed equity ownership rate.

Businesses with the characteristics of the BEE are likely to be at least as attractive to foreign investors as listed companies. This is evident from:

- the large proportion of privately owned network businesses that are partly or wholly foreign owned (refer to the table below); and
- the interest shown by foreign investors in recent sales of network businesses.[987]

Table 10.15 Foreign ownership of privately owned network businesses in Victoria and South Australia

Business	Foreign Owners (incl. via holding companies)	Foreign ownership Share	Domestic owners	Domestic ownership share
JEN	Singapore Power International, State Grid Corporation	100%	N/A	0%
United Energy	Singapore Power International, State Grid Corporation	34%	DUET Group	66%
Citipower	Cheung Kong Group	51%	Spark Infrastructure	49%
Powercor	Cheung Kong Group	51%	Spark Infrastructure	49%
AusNet	Singapore Power International, State Grid Corporation	51%	N/A	49%[988]
SA Power Networks	Cheung Kong Group/Power Assets	51%	Spark Infrastructure	49%
ElectraNet	State Grid Corporation	80%	Hastings Utilities Trust	20%
Australian Gas Networks	Cheung Kong Group	100%	N/A	0%

Source: CitiPower

The equity ownership rate for all equity is unlikely to be a good proxy for the equity ownership rate for a BEE, since the 'all equity' group will include a very large number of small, privately-owned and family companies, and

987 For example, short-listed bidders for TransGrid assets included consortia that included China State Grid and interests from Canada, Abu Dhabi and Kuwait.

988 This is likely to over-state the level of domestic ownership in AusNet. Of the 49 per cent that is not held by Singapore Power International and State Grid Corporation, it is not clear how much is held by foreign investors. For the purposes of this analysis, it is assumed that none of the remaining 49 per cent is held by foreign investors.

will therefore include many businesses that are comparatively unattractive or inaccessible to foreign investors (e.g. the local corner store).

(B) *Time period for measuring the equity ownership rate*

The AER derived its ranges for the equity ownership rate by considering the range for this metric over a period commencing in July 2000. The period since July 2000 was chosen on the basis that a change in the tax law occurred in July 2000, entitling domestic investors to a refund for excess credits.

There is no apparent basis for taking figures up to 15 years old. Rather, to the extent that domestic equity ownership is relevant, what is required is an estimate that is commensurate with the prevailing conditions in the market, and current rates of equity ownership. It is the current rate of domestic equity ownership that will affect the ability of current investors to redeem (and therefore place some value on) imputation credits. The domestic equity ownership rate at some previous point in time is not relevant to this. The AER’s approach in this regard is entirely inconsistent with the estimate of many other parameters, such as the risk free rate. There is no reason to think that the figures for the prevailing rate of equity ownership are unreliable.

The domestic ownership rate (as analysed by the AER) is currently 0.45 for listed equity and 0.6 for all equity. To suggest that the current equity ownership rate could be as high as 0.55 for listed equity, or as high as 0.68 for all equity, is simply incorrect.

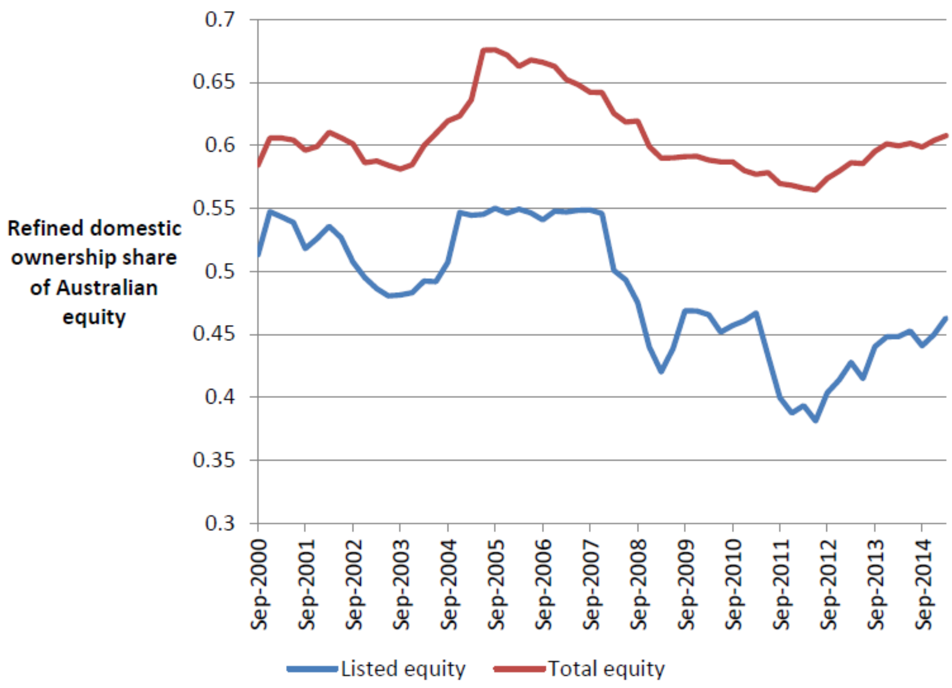
Even if it were appropriate to consider the equity ownership rate over some extended period, the AER’s choice of period is arbitrary. As noted above, the AER justifies its choice of period on the basis that a change in the tax law occurred in July 2000, entitling domestic investors to a refund for excess credits. However the choice of this event as the starting point for the data series is arbitrary, given that there are more recent events (such as the GFC) which are likely to have caused a change in the rate of foreign ownership.

The chart presented in the AER's preliminary determination (reproduced below) shows that the AER’s choice of period is significant to its conclusion on the domestic equity ownership rate. If, for example, the AER had confined its consideration to a period after the onset of the GFC, it would have drawn very different conclusions as to the domestic equity ownership rate. Since September 2008, the domestic equity ownership share has been in a much narrower range of 0.56 – 0.61, and for listed equity it has been in the range of approximately 0.38 – 0.47. This simple change to the period of analysis would have to significantly alter the AER’s conclusion on gamma, since:

- the AER could not have identified an overlap between its estimates of gamma based on equity ownership for listed and all equity. Taking the more recent (post-GFC) period to measure the equity ownership rate leads to a range for gamma of 0.29 – 0.36 based on listed equity measures, and a range of 0.40 – 0.43 based on all equity. Since there is no overlap between these ranges, it is not clear how the AER would have derived a primary range for gamma had it used a shorter period of analysis for the equity ownership rate; and
- if this more recent period were to be adopted, the AER’s gamma estimate of 0.4 could not be reconciled with the evidence on the equity ownership rate for listed equity. Indeed, the AER’s estimate of gamma would not be consistent with any of the evidence for listed equity.

Figure 10.9 Refined domestic ownership share of Australian equity

Figure 4-3 Refined domestic ownership share of Australian equity



Source: Australian National Accounts: Finance and Wealth (ABS cat. 5232.0), tables 47 and 48.

Source: AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015

(C) *The relevant measure of the equity ownership rate*

For reasons set out above, to the extent that equity ownership rates are relevant in providing an absolute upper bound for theta, the correct figure to use is the current listed equity figure. The AER's analysis shows that the current listed equity ownership rate is 0.46.[989]

When combined with a distribution rate of 0.7, this evidence indicates that the absolute upper bound for gamma is 0.32. Gamma can be no higher than 0.32, but may be lower than this.

Estimate from tax statistics

The AER concludes that the redemption rate from tax statistics is 0.45, based on analysis by Hathaway and a recent update from NERA.

This estimate is robust and provides a firm upper bound for theta. As noted by NERA, this figure is drawn from the tax statistics that are considered to be more reliable.[990]

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989 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-97.

990 NERA, *Estimating Distribution and Redemption Rates from Taxation Statistics*, March 2015, p 25.

Thus, tax statistics indicate that theta cannot be higher than 0.45, and therefore gamma cannot be higher than 0.32.

Range of estimates from market value studies

The AER considers that market value studies support a range for the utilisation rate of between zero and one.[991]

Although the AER says that it has had 'particular regard' to the SFG (2013) study, it is not clear from the AER's preliminary determination what weight (if any) this study is given by the AER.[992] The AER's final estimate of gamma is clearly inconsistent with the findings of this study.

Besides stating that it has had 'particular regard' to the SFG study, the AER's preliminary determination does not reveal any meaningful consideration of the relative merits of the available market value studies. We propose to rely on a specific market value study, being the study designed to overcome the limitations of prior studies. However, instead of assessing the merits of this particular study, the AER has grouped this study with a range of other studies and sought to assess the merits of this broad group of studies at a very general level only. The AER has not performed any analysis of the relative merits or deficiencies of the SFG study, nor has there been any expert review of this particular study to identify its relative merits or limitations. The only particular consideration given to the SFG study is in the AER's high level assessment of whether its set of general limitations associated with market value studies (discussed in section 0 above) apply to the that study.[993]

The AER appears to consider that all market value studies should be given equal (or similar) weight, regardless of the:

- time period for estimation (including whether the study relates to the period before or after changes to the tax law in 2000);
- robustness of the methodology; and
- quality of data and filtering techniques.

This is an erroneous and unreasonable approach to consideration of market value studies. As the AER is aware, many of the earlier market value studies have methodological shortcomings and rely on very old data. As explained above, the SFG study relied on by us was specifically designed to overcome the shortcomings of previous studies. In particular, the methodology used in the SFG study:

- was designed, at the request of the Tribunal, to overcome shortcomings in previous studies (particularly the Beggs and Skeels (2006) study);
- was the product of a consultative process involving the AER;
- relies on more recent data than previous studies; and
- has been endorsed by the Tribunal.

In effect, the SFG study was designed to supersede previous studies, both in terms of its methodology and the currency of the underlying data.

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991 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-19.

992 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-32.

993 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 4-107 to 4-111.

As noted above, the SFG study was found by the Tribunal (at the time of its May 2011 decision in Energex) to be 'the best dividend drop-off study currently available'.[994] The Tribunal also did not accept the submission of the AER that either minor issues in the construction of the database or econometric issues justified giving the SFG study less weight and earlier studies (particularly the previous Beggs and Skeels (2006) study) some weight. The Tribunal observed that 'the Beggs and Skeels study, despite not being subjected to anything like the same level scrutiny [sic], is known to suffer by comparison with the SFG study on those and other grounds'.[995]

Unlike the Tribunal in Energex, the AER in its preliminary determination gives no consideration to the relative strengths and weaknesses of the available market value studies. Rather, the AER has simply grouped all market value studies together and referred to a range of estimates emerging from this broad group.

The approach taken in the AER's preliminary determination is even more simplistic than the approach in the RoR Guideline. In the Guideline, the AER at least excluded studies from the pre-2000 period when different tax laws were in operation. However, in the AER's preliminary determination, the AER has brought back the pre-2000 studies, the effect of which is to widen the AER’s range of theta estimates from 0 – 0.5 to 0 – 1.0. Again, this simple change has significant implications for the AER’s conclusion on gamma – if the range were restricted to 0 – 0.5 based on the post-2000 studies, this would indicate a range for gamma of 0 – 0.35 (based on a distribution rate of 0.7) or 0 – 0.39 (based on a distribution rate of 0.77), in any case below the AER’s final point estimate.

We maintain our view that the best estimate of theta from market value studies is 0.35. This reflects the output of the best dividend drop-off study currently available.

Adjustment to estimates from dividend drop-off studies

The AER states that, as a minimum, the output of the SFG study requires an adjustment for the apparent incorrect valuation of cash dividends that would also be expected to be reflected in the estimated value of distributed imputation credits.[996] The adjustment is to address the AER’s concern that dividend drop off studies, including SFG's study, that estimate a value for cash dividends at a materially different amount to their face value, are not correctly estimating a post-tax value before personal taxes and personal transaction costs.[997] The proposed adjustment is based on advice from Handley and Lally, and involves dividing the value of imputation credits by the value of dividends from the same study.[998] Applying this adjustment to the SFG study would lead to an adjustment of the output from 0.35 to 0.40.

The proposed adjustment is an extension of the AER’s conceptual framework for estimating gamma. The AER expresses concern that market value studies are not producing estimates on a pre-personal-tax and pre-personal-costs basis, and it therefore makes an adjustment to remove the effect of these factors.

For reasons set out under the heading 'The AER's conceptual approach to estimating gamma' above, we do not agree with the AER’s conceptual framework. Specifically, we do not agree that gamma should be estimated on a pre-personal-tax and pre-person-costs basis. For the same reasons, we do not agree that the output of market value studies should be adjusted to remove the effect of personal taxes and personal transaction costs.

We note however that if the AER’s view on the conceptual framework were to be accepted, the Handley / Lally adjustment would provide a simple way of adjusting market value studies so that they could be used within this

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994 *Application by Energex Limited (Gamma) (No 5)* [2011] ACompT 9 at [29].

995 *Application by Energex Limited (Gamma) (No 5)* [2011] ACompT 9 at [29].

996 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-32.

997 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 4-31 to 4-32.

998 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-30].

framework.[999] As noted above, if the Handley / Lally adjustment is applied to the SFG study, this leads to a theta estimate of 0.4. This implies that even if the AER's conceptual framework were to be adopted, a reasonable estimate of theta is likely to be around 0.4, implying a gamma of approximately 0.3.

Pairing of estimates for 'all equity' and 'listed equity'

In the AER's preliminary determination, the AER pairs estimates of theta based on listed equity data with its distribution rate for listed equity, and similarly pairs estimates of theta based on all equity data with its distribution rate for all equity. The AER considers that it would be inappropriate to pair an estimate of theta from only listed equity with an estimate of the distribution rate from all equity (and vice versa).[1000]

The AER does not explain why it is necessary or desirable to use the same set of companies to estimate the distribution rate and theta. Rather, the AER appears to consider that consistency of datasets is desirable in and of itself.

We do not agree that estimates of theta based on listed equity data can only be 'paired with' a listed equity distribution rate. The distribution rate and theta are separate parameters and need not be estimated using the same dataset. Whereas the distribution rate is a measure of the credit distribution practices of the BEE, theta is a measure of the value of credits to investors (or potential investors). In each case it must be considered which dataset or empirical measure will provide the best estimate for the BEE, and there is no reason why this ought to be the same across all parameters.

For reasons discussed above, the appropriate dataset for estimating the distribution rate may well be different to that used for estimating theta. This is because the characteristics of investors (or potential investors) in the BEE are likely to be more aligned with investors in listed entities, but the credit distribution rate of the BEE is unlikely to be aligned with that of a large listed entity. The BEE is likely to be at least as attractive to foreign investors as a listed entity, but unlike many large listed entities, it will not have material foreign earnings (which tend to increase the distribution rate for large listed entities).

It is for this reason that we propose to adopt the best estimate of each parameter based on the most representative dataset in each case, without the constraint that the datasets for each parameter must be the same.

Approach to deriving an estimate of gamma

The AER's approach to assessment of the empirical evidence in its preliminary determination is illogical and irrational.

The AER's reasoning involves two steps:

- first, the AER determines a range for gamma, based on the 'overlap of the evidence from the equity ownership approach' (i.e. the overlap between the ranges for listed and all equity respectively); and
- secondly, the AER selects a point in that range based on the evidence from tax statistics and market value studies.

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999 We note the AER appears to consider that this adjustment may not be sufficient to remove the effect of all factors affecting investors' valuation of imputation credits, since there may be some factors which affect investors' valuation of imputation credits only, and not dividends (AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 4-107 to 4-108). We do not agree with this reasoning. The AER has not identified what these additional factors are, or to what extent they ought to be ignored in estimating the value of imputation credits to investors. Therefore the AER cannot reasonably conclude that some further adjustment would be warranted, beyond that recommended by Lally and Handley.

1000 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 4-18.

The first step is arbitrary and illogical, since it involves looking for an overlap between the ranges produced by two different measures and then taking that point of overlap as a binding constraint on the gamma estimate. Since the listed and all equity measures of the equity ownership rate are based on different datasets, there is no reason to expect that the ranges produced by these two measures would necessarily overlap. Indeed, as noted above, it is only because the AER takes such a long historical period to estimate its ranges for the equity ownership rate that the two ranges do overlap.

More importantly, there is no reason to expect that the value for gamma would lie at the point of overlap between these two ranges. The point of overlap indicates nothing about the value of gamma. Rather, it is driven by the AER's choice of time period for estimating ranges for the equity ownership rate. The point of overlap can be made larger or smaller (or made to disappear altogether) simply by varying the time period for analysis of the equity ownership rate.

The second step is similarly arbitrary and illogical, in that it uses different types of evidence to indicate where in a (illogical) pre-determined range the final estimate of gamma should lie. What the AER fails to recognise is that the equity ownership rate, the redemption rate and the market value are each measuring different things. The fact that the gamma estimates based on redemption rates and market value studies are both lower than the range of estimates from the equity ownership approach is to be expected, once it is borne in mind what these measures represent. Properly interpreted, the evidence from tax statistics and market value studies indicates that the value for gamma is (as it must by definition be) below the range from the equity ownership approach, not that it is at the lower end of that range.

As a result of this approach, the AER's estimate of gamma can only be reconciled with its range of estimates for the equity ownership rate. The AER's estimate is significantly above the values indicated by tax statistics and market value studies.

The correct interpretation of the empirical evidence

When correctly interpreted, the evidence presented in the AER's preliminary determination demonstrates that:

- the distribution rate for the BEE is approximately 0.7;
- the upper bound for theta, as indicated by equity ownership rates and tax statistics, is approximately 0.45. This implies an upper bound for gamma of 0.32;
- the best estimate of the value of distributed imputation credits, on the AER's conceptual framework (i.e. ignoring personal costs), is 0.4. This implies a gamma of 0.28; and
- the best estimate of the value of distributed imputation credits, based on a proper application of the Rules, is 0.35. This implies a gamma of 0.25.

The AER's gamma estimate of 0.4 is not consistent with the evidence presented in the AER's preliminary determination. This value is well above even the upper bound values indicated by the equity ownership approach and tax statistics.

10.7.4 Our revised regulatory proposal

For the reasons mentioned above, we maintain our proposal for a gamma of 0.25, based on a distribution rate of 0.7 and a theta estimate of 0.35.

Our proposal represents a departure from the methods for estimating gamma set out in the RoR Guideline. Our reasons for departure are set out in this chapter.

10.8 Inflation

10.8.1 Initial regulatory proposal

In our regulatory proposal, we proposed to adopt the AER’s current approach to determining the expected rate of inflation input to the PTRM.[1001] However, our proposed approach was caveated in that it acknowledged the apparent volatility in expectations concerning inflation, both in Australia and globally, and noted that the best approach to determining the expected rate of inflation may evolve during the period in which our proposal was considered by the AER.[1002]

10.8.2 AER's preliminary determination

In the AER's preliminary determination, the AER accepted our proposed method for forecasting inflation for the 2016–2020 regulatory control period.[1003] However, the AER updated our proposed inflation estimate to reflect the most recent RBA forecasts (i.e. as at October 2015), which resulted in a reduction from our proposed forecast inflation rate of 2.60 per cent per annum to 2.50 per cent per annum.[1004]

The AER stated that it would update the forecast inflation rate with a more recent inflation forecast that the RBA will publish before the AER's final decision is made in April 2016.[1005] The AER also noted that it would consider a change to the inflation forecasting method in accordance with the consultation processes mandated by the Rules.[1006]

10.8.3 Our response to the AER's preliminary determination

Background

For the reasons discussed below, we consider that, in current market conditions, the AER's forecasting method is likely to over-estimate inflation. We also outline below what we consider to be a superior inflation forecasting method. Nonetheless, we do not press the adoption by the AER of an inflation forecast derived using this method in this revised regulatory proposal. That is, we will not contest the application of the AER's forecasting method , but only for the purpose of the making of the AER's final decision for the 2016–2020 regulatory control period. This renders our revised regulatory proposal conservative, in the sense that it is likely to lead to under-estimation of efficient costs.

An accurate forecast of inflation is necessary to ensure that businesses have a reasonable opportunity to recover their efficient costs over the long term. Under the Rules, forecast inflation plays a role in determining the amount to be deducted from the annual revenue requirement for indexation of the RAB.[1007] If the forecast of inflation is too high – that is, if actual inflation turns out to be materially lower than had been forecast – this deduction will be too large. This will lead to under-recovery of costs over the long-term, since the amounts deducted from the

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1001 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 240.

1002 CitiPower, *Regulatory proposal 2016–2020*, April 2015, p. 240.

1003 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-255.

1004 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-255.

1005 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-255.

1006 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-256.

1007 Under clause 6.4.3(a) of the Rules, the annual revenue requirement for a distributor for each regulatory year of a regulatory control period must be determined using a building block approach, under which the building blocks include 'indexation of the regulatory asset base'. Pursuant to clause 6.4.4(b) of the Rules, the 'indexation of the regulatory asset base' building block comprises a negative adjustment equal to the amount referred to in clause S6.2.3(c)(4) for that year – i.e. the amount necessary to maintain the real value of the RAB as at the beginning of the subsequent year by adjusting that value for inflation.

annual revenue requirement will be larger than the amount by which the asset base is increased by inflation at the end of the regulatory control period (this being based on actual inflation[1008]).

The forecast of inflation also bears an interrelationship with the allowed rate of return. The reason why there needs to be a deduction from the annual revenue requirement for indexation of the RAB is because, under the Rules, a nominal rate of return is used[1009] in combination with a real (inflation-adjusted) RAB.[1010] Without the deduction, service providers would be compensated twice for the effects of inflation – once through the rate of return, and again through indexation of the RAB. It is therefore important that the forecast of inflation used to calculate the revenue deduction be:

- accurate (i.e. as close as possible to actual inflation, which is used to roll forward the RAB at the end of the regulatory control period); and
- consistent with the implied forecast of inflation in the nominal rate of return.

In the AER's preliminary determination, the AER adopted an inflation forecast of 2.5 per cent for the 2016–2020 regulatory control period. This is based on the methodology that has been adopted by the AER since 2008, which involves:[1011]

- for the first two years of the regulatory control period, taking the mid-point of the RBA forecast range for CPI inflation. For these two years, the RBA has published a forecast range of 2 to 3 per cent, with a mid-point of 2.5 per cent;[1012] and
- for the following eight years, taking the mid-point of the RBA target range for CPI inflation, being 2.5 per cent (as this range is 2 to 3 per cent).

As RBA forecasts are only used for the first two years of the regulatory control period, the inflation forecast derived using this methodology is primarily determined by the mid-point of the RBA's target range. This approach is reasonable where investors expect monetary policy to return inflation to, and maintain it at, the mid-point of the RBA's target range.

In our regulatory proposal, we had adopted the current AER method for forecasting inflation, as described above. However, we also foreshadowed a review of their method for estimating forecast inflation if current market conditions persist.

Shortcomings of the AER method in current market conditions

Recent market evidence demonstrates that the AER’s current forecasting method is currently over-estimating inflation. In particular, the most recent Australian Bureau of Statistics (**ABS**) data shows that actual CPI inflation is well below the RBA’s forecasts and target range – year-end CPI inflation for the June and September quarters was 1.5 per cent per annum, while for the March quarter it was 1.3 per cent.

[1008] NER, clause 6.5.1(e)(3).

[1009] NER, clause 6.5.2(d)(2).

[1010] NER, clause 6.5.1(e)(3).

[1011] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-256.

[1012] RBA, *Statement on Monetary Policy*, November 2015, Table 6.1.

Table 10.16 Comparison of actual inflation with RBA and AER forecasts

Year ended	Actual inflation	RBA forecast (as at May of the prior year)	Forecast based on AER method (as at May of the prior year)
June 2013	2.4%	2 – 3%	2.5%
June 2014	3.0%	2 – 3%	2.5%
June 2015	1.5%	2.5 – 3.5%	2.55%

Source: CitiPower

With RBA cash rates at record low levels and with near term rate cuts priced into financial markets, the RBA cash rate is close to the 'zero lower bound', with the result that the potential for monetary policy to stimulate economic activity and return inflation to the RBA's target range for CPI inflation is diminished.

The consequence of this is that:

- the AER’s method is likely to result in an inflation forecast that is above market expectations of inflation over the regulatory control period;
- the inflation forecast used to make adjustments to cash flows (based on the AER inflation forecast) is likely to be inconsistent with the forecast of inflation implied in the nominal rate of return (which reflects market expectations);
- the downward adjustment to depreciation cash flows is expected to be too large—because the inflation forecast derived using the AER's method is expected to be higher than the actual inflation used to roll forward the RAB from 2016 to 2021—thus artificially depressing the overall return to investors; and
- over the long-term, we will not be able to recover our capital costs.

Return to a market-based method

We consider that an alternative forecasting method, based on market data, is to be preferred to the AER's forecasting method. The alternative method is referred to as the ‘Fisher equation’ method, or the ‘breakeven inflation’ forecasting method. Under this method, an estimate of expected inflation is derived using a simplified version of the Fisher equation, based on the difference in yields on nominal and inflation indexed CGS of the same maturity.[1013]

The Fisher equation method was used by the AER prior to 2008. The AER only changed to its current method in 2008 as a result of market conditions at that time causing a scarcity of CGS. In its decision to move away from the Fisher equation method, the AER agreed with stakeholders that a market-based estimate of forecast inflation would be preferable, but concluded that due to market conditions at that time its market-based measure was likely to be unreliable. The AER therefore departed from the PTRM method for forecasting inflation (the Fisher equation method) and sought an alternative method that it considered would provide the best estimate of expected inflation. The AER concluded:[1014]

[1013] CEG, *Measuring expected inflation for the PTRM*, June 2015, p. 10; CEG, *Measuring risk free rates and expected inflation: A report for United Energy*, April 2015. CEG refers to this as the ‘breakeven inflation’ forecasting method. CEG notes that the equation it uses is a simplified version of the Fisher equation.

[1014] AER, *Final decision*, *SP AusNet transmission determination 2008-09 to 2013-14*, January 2008, pp. 105 to 106.

The AER's approach to forecasting inflation in this final decision has been in response to an acceptance that the previously ubiquitously used Fisher equation may not currently produce realistic inflation forecasts at this time, due to a bias in indexed CGS yields caused by the scarcity of these bonds. The AER considers that a market based estimate derived from a robust methodology would be preferred to any other alternative method, as the former typically results in a greater degree of certainty and objectivity, however, it is not possible to use such a method at this time…

The AER has determined that a methodology that is likely to result in the best estimates of expected inflation is to reference the RBA's short term inflation forecasts, that currently extend out two years, and to adopt the mid-point of the RBA's target inflation band beyond that period (i.e. 2.5%).

We agree with the AER that a market-based estimate of inflation is preferable to an estimate based on the RBA forecasts and target range. A market-based estimate is more likely to be consistent with expectations of inflation reflected in the nominal rate of return, and more likely to be reflective of actual inflation over the regulatory control period.

Further, the limitations that applied to the Fisher equation method in 2008 no longer apply. Dr Hird notes that during the period from 2006 to late 2008 the indexed CGS market was much smaller than today, and this shortage of supply combined with high demand was pushing up indexed CGS prices and pushing down real yields, with the effect that Fisher equation estimates were overstated.[1015] However, Dr Hird explains that since that time the supply of indexed CGS has increased considerably, thus alleviating concerns regarding the accuracy of the breakeven forecasting method:[1016]

At that time the Australian Office of Financial Management was not issuing new indexed linked securities and there were doubts about its commitment to maintain a supply of these bonds into the future. However, since then the AOFM has recommenced issuance of these bonds and the stock of bonds have increased by more than 400% and the number of different maturity dates have more than doubled from 3 to 7. The AOFM has also announced the imminent issuance of a new 2040 or 2045 CPI indexed bond.

On this basis I consider that the shortage of supply of these bonds which led to breakeven inflation overstating expected inflation prior to 2009 is no longer a material concern. In any event, to the extent that it this was a material concern it would imply that breakeven inflation would be overestimating expected inflation which, if true, would suggest the AER's methodology (which forecasts higher inflation than breakeven inflation currently) was overestimating by even more.

In recent years, the current AER method has delivered similar outcomes to the Fisher equation method, because market expectations have been broadly in line with the RBA's forecasts and target range. Therefore, until now, there has been no pressing need for the AER to change its inflation forecasting method.

However there is now a material divergence between the RBA forecasts / targets and market-based measures of inflation expectations. There has also been a material divergence between the RBA forecasts / targets and out-turn inflation over the past year, as shown in the table above.

During the development of the RoR Guideline, forecasts produced using the Fisher equation were close to those produced by the AER's methodology (see table 9). Therefore, at that time, it was unsurprising that stakeholders endorsed the continuation of the current approach when asked their views. The situation has since changed materially and the AER should not rely on outdated stakeholder support for its approach to satisfy itself that its

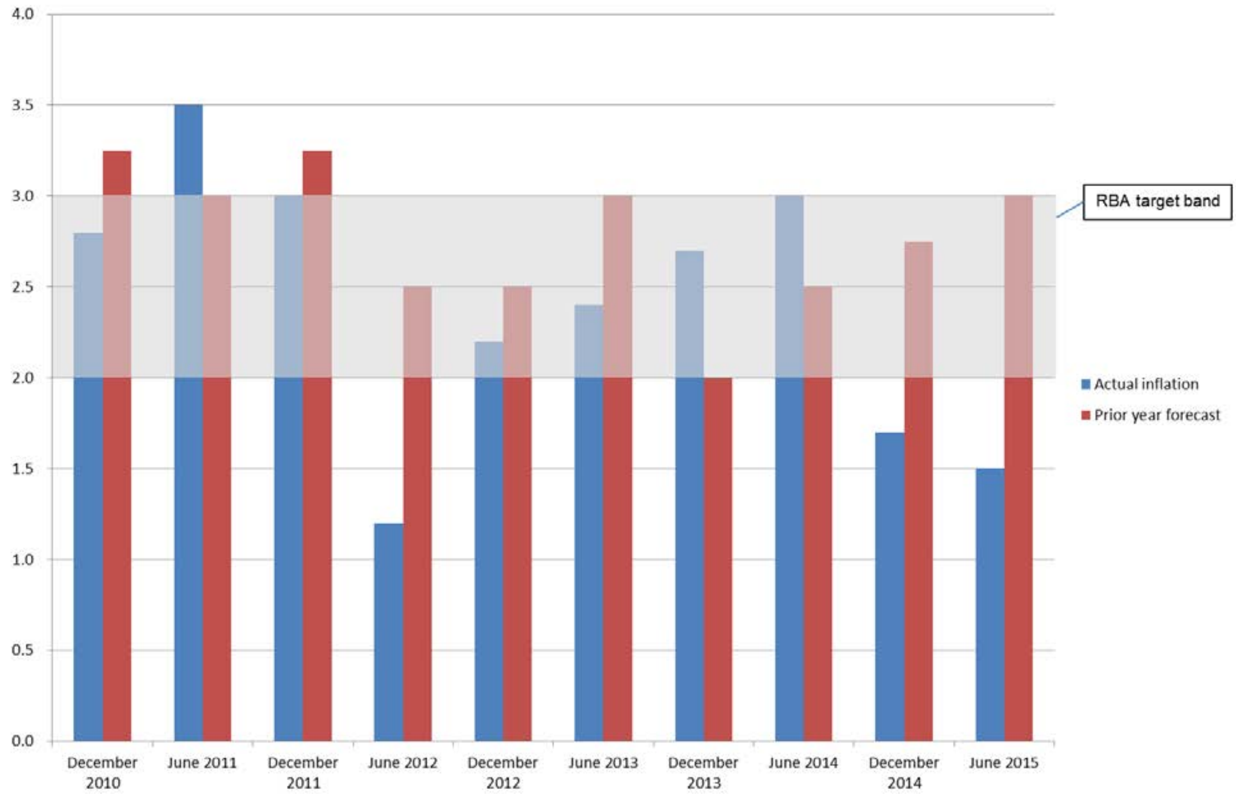
[1015] CEG, *Measuring expected inflation for the PTRM*, June 2015, p. 7.

[1016] CEG, *Measuring expected inflation for the PTRM*, June 2015, p. 7.

approach is appropriate in the current environment. It is also worth noting that those views where never incorporated into the final guideline.

The evidence demonstrates that over the past year, actual inflation has been significantly lower than RBA forecasts and well below the RBA's target band (see the following figure).

Figure 10.10 Actual inflation vs prior year RBA forecast and RBA target band[1017]



Source: RBA and ABS

Further, Dr Hird explains that over the medium term, it is more likely that actual inflation will be below the mid-point of the RBA's target range. Dr Hird notes that, with the RBA cash rate at record low levels, the power of monetary policy to spur economic growth and increases in the inflation rate is now more limited. Dr Hird concludes:[1018]

> *In this context, it is reasonable to expect that investors perceive an asymmetry in the probability that inflation will be above/below the RBA's target, at least in the medium term. This means that, even if the 'most likely' estimate is for expected inflation to average 2.5% in the medium to long term, this is not the mean (probability weighted) estimate. That is, there is more downside than upside risk to inflation.*

[1017] Actual inflation data reflects the annual change in CPI over year to June / December (as relevant), as reported by the ABS. The prior year forecast for each December and June quarter is the RBA forecast for the relevant quarter, as set out in the RBA's Statement on Monetary Policy for May of the prior financial year (e.g. for the December 2014 and June 2015 quarters, the prior year forecast is as set out in RBA, *Statement on Monetary Policy*, May 2014).

[1018] CEG, *Measuring expected inflation for the PTRM*, June 2015, p. 10.

This implies that it is no longer reasonable to expect inflation to revert to the middle of the RBA target range over the medium term. Accordingly, in current market conditions, a methodology that assumes medium term inflation would be at or around the mid-point of the RBA target range (as the current AER method does) is likely to over-estimate forecast inflation.

We therefore consider that the Fisher equation method for forecasting inflation is now the better forecast method. Since the Fisher equation method provides a market-based estimate of inflation, use of this method would:

- promote consistency between the inflation forecast used to make adjustments to cash flows and the forecast of inflation implied in the nominal rate of return;
- provide for an inflation forecast that is more likely to be reflective of actual inflation over the regulatory control period; and
- provide businesses with a reasonable opportunity to recover their efficient costs over the long-term, since the inflation forecast used to calculate deductions from the revenue allowance will be more consistent with actual inflation, which is used to roll forward the RAB over time.

We further consider that the Fisher equation method should be implemented in the manner recommended by CEG, which places 60 per cent weight on a 5-year inflation forecast and 40 per cent weight on a 10-year forecast.[1019] CEG explains that a 5-year forecast should be used for indexation of the portion of the RAB that is assumed to be debt financed, since the business' debt financing obligations over the 5-year regulatory control period are in nominal terms. However, for indexation of the equity-financed component of the RAB, a 10-year forecast should be used in order to effectively convert the 10-year nominal return on equity to a real return on equity.

We also agree with CEG's recommendation to substitute actual inflation into the 5-year forecast used for indexation of the debt-financed portion of the RAB, where actual observations are available.[1020]

This alternative method delivers an inflation forecast of 1.94 per cent, based on an application of the Fisher equation method over the 20 business days to 30 September 2015.

AER proposal for separate consultation on the inflation forecasting method

In the AER's preliminary determination, the AER states that, going forward, it would consider a change to inflation forecasting in accordance with the consultation processes mandated by the Rules. The AER also suggests that the next rate of return guideline review may be a suitable process for also reviewing the inflation forecasting method.[1021]

It is not clear to us why a change to the inflation forecasting method could only be considered as part of a separate consultation process (if that is what the AER is suggesting) or why it could not be considered by the AER as part of making its distribution determination for us.

We consider that the AER must consider the appropriateness of the inflation forecasting method at the time of each distribution determination. This is because:

1019 CEG, *Measuring expected inflation for the PTRM*, June 2015, section 3.

1020 CEG, Measuring expected inflation for the PTRM, June 2015, pp. 24 - 25.

1021 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-256.

- the Rules require that the annual revenue requirement for each regulatory year include an adjustment equal to the amount by which the RAB is adjusted for inflation in that year,[1022] and it is therefore necessary for the AER to determine a forecast of inflation, as an input or value to be used in its decision on the annual revenue requirement;
- the Rules also require that, as part of a building block determination, the AER specify appropriate methods for the indexation of the RAB;[1023]
- the AER's distribution determination is predicated on a decision on the annual revenue requirement for each regulatory year, which is to include an adjustment equal to the amount by which the RAB is adjusted for inflation in that year;[1024] and
- the AER's distribution determination is also predicated on a decision as to appropriate amounts, values or inputs to be used in determining the annual revenue requirement for each regulatory year, which necessarily include a forecast of inflation for each year.[1025]

We understand that the AER may be concerned that, since the PTRM is required to include a method for estimating inflation, the only way in which the forecasting method could be changed is through an amendment to the PTRM.

If this were to be the AER's concern, we consider that it would be unfounded. The Rules do not require that the inflation forecast used to calculate the 'indexation of the regulatory asset base' building block be determined in accordance with the inflation forecasting method specified in the PTRM. On the contrary, the Rules state that, as part of a building block determination, the AER must specify appropriate methods for the indexation of the RAB.[1026] Further, as noted above, the AER's distribution determination is predicated on a decision as to appropriate amounts, values or inputs to be used in determining the annual revenue requirement for each regulator year, which necessarily include a forecast of inflation for each year.[1027] The fact that an inflation forecasting methodology is specified in the PTRM does not relieve the AER of its duty under the Rules to determine an appropriate forecast of inflation for each regulatory year of the 2016–2020 regulatory control period.

The AER has not previously expressed any reservation about considering a change to the inflation forecasting method as part of a revenue determination process. On the contrary:

- during the RoR Guideline process, the AER deferred consideration of the inflation forecasting method, on the basis that it would be considered in upcoming determinations. The AER stated in its explanatory statement:[1028]

  As discussed with stakeholders, the final guideline does not cover our position on transactions costs or forecast inflation. These issues will need to be considered in upcoming determinations.

- as noted above, the AER has previously adopted an inflation forecasting methodology that was different to that set out in its PTRM and applied in previous determinations. In its January 2008 determination in respect of SP AusNet the AER did not apply the Fisher equation method, even though the Fisher equation method

[1022] NER, clause 6.4.3.

[1023] NER, clause 6.3.2(a).

[1024] NER, clause 6.12.1(2).

[1025] NER, clause 6.12.1(10).

[1026] NER, clause 6.3.2(a).

[1027] NER, clause 6.12.1(10).

[1028] AER, *Better Regulation, Explanatory Statement, Rate of Return Guideline*, December 2013, p. 21.

had been applied up until that time, and was the method included in the PTRM at the time SP AusNet submitted its revenue proposal.[1029] The AER stated that in considering SP AusNet's revised proposal, it was guided by the principle that the appropriate approach to forecasting inflation should be a methodology that the AER determines is likely to result in the best estimates of expected inflation.[1030]

Nonetheless, notwithstanding the evidence that the AER's current method is not producing accurate forecasts of inflation, we will await the AER reviewing its inflation forecasting method as part of a consultation process separate to the process for the making its distribution determination for the 2016–2020 regulatory control period for us.

10.8.4 Our revised regulatory proposal

For reasons set out above, we consider that an alternative forecasting method, based on market data, is superior to the AER's forecasting method. The alternative method is referred to as the 'Fisher equation' method, or the 'breakeven inflation' forecasting method. Under this method, an estimate of expected inflation is derived using a simplified version of the Fisher equation, based on the difference in yields on nominal and inflation indexed CGS of the same maturity. Based on this alternative method, the current best estimate of forecast inflation is 1.94 per cent.

Nonetheless, as noted above, we do not press the adoption of this alternative method in this revised regulatory proposal. We will not contest the AER's forecasting method, which (on currently available information) results in an inflation forecast of 2.5 per cent, to be applied in the making of the AER's final decision for the 2016–2020 regulatory control period.

10.9 Interrelationships

The Rules require that, in determining the allowed rate of return, regard be had to any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.[1031]

This section addresses relevant interrelationships involving the financial parameters discussed above.

Need for consistent application of the ARORO

We consider that the return on equity and return on debt need to be estimated on the basis of a consistent approach to the ARORO.

As discussed in section 10.3.2 above, we see the ARORO as having two key elements:

- first, the ARORO requires identification of the level of risk that applies to the distributor in respect of the provision of standard control services; and
- secondly, the ARORO requires estimation of efficient financing costs for a BEE facing a similar degree of risk.

Our proposed approaches to estimating the return on equity, return on debt and the overall rate of return apply this framework consistently. Specifically:

[1029] AER, *Final decision*, *SP AusNet transmission determination 2008-09 to 2013-14*, January 2008, pp. 105 - 106. As noted by the AER, the first PTRM (which applied until September 2007) used the Fisher equation to estimate inflation (in the 'WACC' worksheet, cell F9).

[1030] AER, *Final decision*, *SP AusNet transmission determination 2008-09 to 2013-14*, January 2008, p. 102.

[1031] NER, clause 6.5.2(e).

- we consider that the relevant degree of risk, for the purposes of estimating both the return on equity and return on debt, is that faced by entities operating in a workably competitive market providing services similar to standard control services within Australia;
- in estimating both the return on equity and return on debt, our objective is to estimate the efficient financing costs of a BEE facing a similar degree of risk. This requires consideration of what financing practices would be engaged in by businesses facing the relevant degree of risk, operating in a workably competitive market. This is because it is ultimately competition that drives efficient behaviour. For example, our proposed approach to estimating the return on debt reflects financing practices that would be engaged in by businesses facing the relevant degree of risk, operating in a workably competitive market. Similarly, our estimates of the return on equity are benchmarked against returns required by the market for investing in businesses with a similar degree of risk, including those operating in competitive markets;
- where we are required to estimate risk parameters, we do so on the basis of samples of businesses facing a similar degree of risk to that faced by entities operating in a workably competitive market providing services similar to standard control services. The businesses included in these samples need not be providers of regulated services, but they must provide services that are sufficiently similar. For example in estimating the equity beta, our proposed sample of businesses includes businesses operating in workably competitive markets providing services similar to standard control services. Similarly, in estimating the return on debt, yields are measured using benchmark indices for the relevant credit rating band, with those indices reflecting bond yields across a wide range of businesses within that credit rating band, including businesses operating in competitive markets (i.e. a range of different businesses facing a similar degree of risk as assessed by credit rating agencies); and
- our assumed gearing ratio of 60 per cent is broadly consistent with evidence of gearing ratios for businesses operating in a workably competitive market providing services similar to standard control services. If anything, the evidence suggests that 60 per cent may overstate gearing levels for such businesses, meaning that adopting this gearing assumption is likely to lead to a conservative (low) estimate of the overall rate of return.[1032]

Thus, our proposed approaches to estimating the return on equity, return on debt and the overall rate of return, as set out above, are both consistent with the approach to the ARORO described in section 10.3.2 above.

Interrelationship between the return on equity and the value of imputation credits

There is a well-recognised interrelationship between the return on equity and the value of imputation credits. Since the MRP needs to be grossed up for the value of imputation credits, a higher theta estimate implies a higher required return on equity. This interrelationship is explicitly recognised in the Rules.[1033]

This interrelationship is accounted for in this revised regulatory proposal and the supporting expert advice. As explained by Frontier Economics[1034], the proposed MRP estimate of 7.9 per cent is based on AER estimates of the MRP from historical excess returns and the DGM that assume a value for theta of 0.6. However Frontier

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[1032] Frontier Economics analyses average gearing ratios across a sample of listed Australian infrastructure firms, including both regulated and unregulated businesses. Frontier notes that, while the mean gearing ratio across this sample is slightly below 60%, this is almost entirely due to the very low leverage levels of two entities – Aurizon (which began its life as a public company with very little debt and has stated its intention to increase leverage over time) and Qube (which is in the process of seeking to acquire Asciano and has maintained low leverage to preserve borrowing capacity). Refer to: Frontier Economics, Estimating the equity beta for the benchmark efficient entity, January 2016, p 21.

[1033] NER, clause 6.5.2(d)(2).

[1034] Frontier Economics, *The required return on equity under a foundation model approach*, January 2016, pp 34-37.

Economics notes that the impact on these estimates of adopting a lower theta value (e.g. a value of 0.35) is relatively small, particularly when compared to the effect of variation in the other factors that affect the estimate of the MRP. Frontier Economics considers that the AER's estimates of the MRP from historical excess returns and the DGM are conservative in that the AER's historical returns estimate does not reflect the NERA correction for historical dividends and the AER's DGM estimates are based on ad hoc reductions to long-term GDP growth rates. Frontier notes that correcting for these effects would more than offset any adjustment needed to account a reduction in the estimate of theta from 0.6 to 0.35.

If the AER were to reduce its estimate of theta to 0.35, while maintaining its current approach to estimating the MRP, no adjustment to the AER's MRP estimate would be necessary. This is because the top of the AER's range of estimates of the historical average MRP (used by the AER as its MRP point estimate) would remain at 6.5 per cent.[1035]

Interrelationships with the inflation forecast

As noted above, there is an interrelationship between the method for forecasting inflation and the amount that is deducted from the annual revenue requirement for indexation of the RAB, and between the allowed rate of return and the method for forecasting inflation.

The first of these interrelationships is a direct interrelationship. If the forecast of inflation is too high – that is, if actual inflation turns out to be materially lower than had been forecast – the deduction from the annual revenue requirement will be too large. This will lead to under-recovery of costs over the long-term, since the amounts deducted from the annual revenue requirement will be larger than the amount by which the asset base is increased by inflation at the end of the regulatory control period (this being based on actual inflation[1036]).

The second of these interrelationships is more indirect. As noted above, the deduction from the annual revenue requirement for indexation is needed to avoid 'double counting' of inflation. In effect, inflation is counted twice (i.e. because, under the Rules, a nominal rate of return is used[1037] in combination with a real (inflation-adjusted) RAB[1038]) and deducted once. It is therefore important that each time it is counted or deducted, a consistent approach to forecasting inflation is used.

The forecast of inflation used to calculate the revenue deduction therefore needs to be:

- accurate (i.e. as close as possible to actual inflation, which is used to roll forward the RAB at the end of the regulatory control period); and
- consistent with the implied forecast of inflation in the nominal rate of return.

It is for this reason that we consider that a market-based estimate of forecast inflation is to be preferred to the AER's forecasting method. Using a market-based method ensures consistency with how the allowed rate of return is estimated, and in current market conditions, will provide for a more accurate forecast. Nonetheless, as

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1035 For reasons set out under the heading 'The AER's application of the SL-CAPM' in section 10.4.3, we do not agree with the AER's approach to estimating the MRP. However we note that if the AER were to maintain the same approach to estimating the MRP while lowering its estimate of theta, its estimate of the MRP would not need to change. NERA provides estimates of the historical average MRP based on theta assumptions of 0.35 and 0.6. Over the longest available time period, NERA estimates a historical average MRP of 6.65 per cent using a theta assumption of 0.6, and 6.56 per cent using a theta assumption of 0.35 (NERA, *Historical Estimates of the Market Risk Premium*, February 2015, pp. 42 to 43). Thus, NERA's analysis shows that if the AER were to reduce its theta estimate from 0.6 to 0.35, the top of the range for the historical average MRP (which the AER uses as its MRP point estimate) would remain at approximately 6.5 per cent.

1036 NER, clause 6.5.1(e)(3).

1037 NER, clause 6.5.2(d)(2).

1038 NER, clause 6.5.1(e)(3).

discussed above, we do not press the adoption of a market-based estimate of forecast inflation in this revised regulatory proposal.

Claimed interrelationship between the approach to the return on debt and equity beta

In the AER's preliminary determination, the AER suggests that there may be an interrelationship between the choice of method for estimating the return on debt (in particular, whether a trailing average method is adopted) and the equity beta. It is suggested that, to the extent there is a degree of 'mismatch risk' due to the choice of method for estimating the return on debt (i.e. a risk that the allowed return on debt does not reflect the debt financing costs of a BEE), this ought to be accounted for in estimating the equity beta.[1039]

We do not accept that there is this interrelationship between the transition method for estimating the return on debt and the equity beta. The risk of a mismatch between the regulatory allowance for the return on debt and efficient financing costs is not a non-diversifiable systematic risk.

Chairmont, in its report to the AER, makes this point clear:[1040]

> *Interest rate risk per se is a systematic risk for all or most companies in the market. However, the form of interest rate risk applicable to NSPs in the 'on-the-day' regime was something quite specific to firms under that regulatory umbrella. Most industries would have had greater total interest rate risk than regulated NSPs, as most enterprises do not have the benefit of a direct link between the interest rate impact of their revenues and their costs which NSPs do. This places NSPs in a better position than an unregulated business, as the allowance is in effect a revenue item that they can manage to, even with the uncertainties of the DRP mismatch component.*
>
> *Ex-post results for the DRP mismatch would have impacted the profit results of the NSPs, which may then have caused some benefit or drag to the share price of the specific NSP. However, it may be argued that this is not a systematic risk. The variability of cashflow is specific to the industry and the individual NSP and may be diversifiable by investors. If this is so, then the required return on equity would not be affected by the DRP mismatch risk as it was a diversifiable specific risk rather than a component of market systematic risk. Therefore, the return on equity should be the same regardless of the existence of DRP mismatch risk and beta should not change because of it.*

It follows that any change in the AER's approach to estimation of the return on debt (including any change to the transition method) will not affect the return on equity.

[1039] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 3-176.

[1040] Chairmont, *Financing Practices Under Regulation: Past and Transitional*, 13 October 2015, p. 40.

Revenue requirement 11

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11 Revenue requirement

This chapter provides a summary of our proposed 2016–2020 annual revenue requirements for standard control services. The building block approach required by the National Electricity Rules (**Rules**) for the calculation of revenue requirement for standard control services has been applied.

The Australian Energy Regulator's (**AER's**) post tax revenue model (**PTRM**) has been used to calculate the revenue requirement. We have not departed from the AER's published PTRM.[1041]

11.1 Rule requirements

Clause 6.4.3 of the Rules requires the application of a building block approach to determine the annual revenue requirements (**ARR**) for standard control services.

The building blocks are set out in clause 6.4.3(a) of the Rules and include:

- the indexation of the regulatory asset base (**RAB**);
- a return on capital;
- depreciation;
- the estimated cost of corporate income tax;
- revenue adjustments (if any) arising from the application of the efficiency benefit sharing scheme (**EBSS**), capital expenditure sharing scheme (**CESS**), the service target performance incentive scheme (**STPIS**), the demand management and embedded generation connection incentive scheme or small scale incentive scheme;
- other revenue adjustments (if any) arising from the application of the control mechanism in the previous regulatory control period;
- revenue adjustments (if any) arising from the use of assets that provide standard control services to provide certain other services; and
- forecast operating expenditure.

The development of most of these building blocks has been described in earlier chapters of this revised regulatory proposal.

11.2 Initial regulatory proposal

In our initial regulatory proposal, we proposed ARRs and X factors as set out in table 11.1 below.

Table 11.1 Revenue requirement ($ million, nominal)

	2016	2017	2018	2019	2020
Return on assets	129.9	139.2	151.0	161.7	170.2
Regulatory depreciation	51.8	51.3	57.8	64.7	71.8
Operating expenditure	95.9	99.9	111.0	116.9	119.9

1041 CP PUBLIC RRP MOD 1.10 - AER, *CP 2016-20 PTRM*.xlsm

	2016	2017	2018	2019	2020
EBSS efficiency carryover	-3.7	-2.1	0.8	-2.0	-
S factor true up	1.6	-	-	-	-
Shared asset revenue reduction	-	-	-	-	-
Corporate income tax	25.9	25.5	25.4	25.6	28.2
Unsmoothed revenue requirement	301.4	313.7	345.9	366.8	390.1
Smoothed revenue requirement	303.3	322.1	342.0	363.2	385.7
Forecast CPI %	2.60	2.60	2.60	2.60	2.60
Revenue X factor (%)[1042]	0.12	-3.50	-3.50	-3.50	-3.50

Source: CitiPower, *Regulatory Proposal 2016–2020,* April 2015, Table 13.9

11.3 AER's preliminary determination

In the preliminary determination, the AER determined that our ARRs and X factors should be set as shown in table 11.2.

Table 11.2 AER conclusion on revenue requirement ($ million, nominal)

	2016	2017	2018	2019	2020
Return on assets	108.0	113.9	120.3	125.2	129.6
Regulatory depreciation	57.9	56.3	59.4	62.9	68.1
Operating expenditure	81.4	84.9	89.1	93.1	97.2
EBSS efficiency carryover	-0.13	-2.81	1.05	-1.44	-
S factor true up	1.58	-	-	-	-
Shared asset revenue reduction	-0.30	-0.30	-0.31	-0.32	-0.33
Demand management incentive scheme	0.21	0.21	0.22	0.22	0.23
Corporate income tax	15.8	14.3	13.5	14.3	14.9
Unsmoothed revenue requirement	264.5	266.5	283.3	293.9	309.7
Smoothed revenue requirement	282.9	270.4	278.4	286.6	295.1
Forecast CPI %	2.50	2.50	2.50	2.50	2.50
Revenue X factor (%)[1043]	6.75	6.75	-0.45	-0.45	-0.45

Source: CitiPower, *AER Preliminary Decision, CitiPower distribution determination 2016–20 ,Overview*, October 2015, Table 3

[1042] A positive revenue X factor means a real revenue decrease and a negative revenue X factor means a real revenue increase.

[1043] A positive revenue X factor means a real revenue decrease and a negative revenue X factor means a real revenue increase.

11.4 Our response to the AER's preliminary determination

11.4.1 Roll forward of the RAB to 1 January 2016

The estimated value of our RAB for standard control services as at 1 January 2016 is discussed in chapter 9 of our revised regulatory proposal.

11.4.2 Roll forward of the RAB from 2016 to 2020

The RAB has been rolled forward from 2016 to 2020 in accordance with the Rules using the AER's PTRM and the discussion in chapter 9 of our revised regulatory proposal.

11.4.3 Depreciation

Our calculation for depreciation of the RAB is discussed in chapter 9 of our revised regulatory proposal.

11.4.4 Efficiency benefits sharing scheme

The preliminary determination amended our proposed efficiency benefit sharing scheme allowance. For the purposes of our revised regulatory proposal, we accept the AER's preliminary determination.

Table 11.3 EBSS calculation ($ million, real)

Excluded costs	2011	2012	2013	2014	2015
Regulatory proposal	-3.6	-2.0	0.7	-1.8	-
Preliminary determination	-0.1	-2.7	1.0	-1.3	-
Revised regulatory proposal	-0.1	-2.7	1.0	-1.3	-

Source: CitiPower

11.4.5 S factor true up

The preliminary determination amended our proposed S factor true up amount. For the purposes of our revised regulatory proposal, we accept the AER's preliminary determination.

Table 11.4 S factor true up ($ million, nominal)

	2016	2017	2018	2019	2020
Regulatory proposal	1.6	-	-	-	-
Preliminary determination	1.6	-	-	-	-
Revised regulatory proposal	1.6	-	-	-	-

Source: CitiPower

11.4.6 Shared asset revenue reduction

The preliminary determination did not accept our position that no shared asset revenue reduction was warranted. The AER considered our forecast of 2016 un-regulated revenue as reasonable and accepted these revenues would remain constant in real terms. That said, the AER did not believe we had indexed these revenues for inflation. Further, the AER reduced our smoothed expected revenue allowance as part of the preliminary determination which has resulted in the shared assets revenue threshold being violated.

We accept the approach applied in the preliminary determination however note that we have recalulated the smoothed expected revenue allowance based on our revised regulatory proposal. Recalulating the materiality percentage using our proposed smoothed expected revenue allowance results in the materiality threshold only being breached in 2016. As a result, our revised regulatory proposal includes an adjustment for shared asset revenue only for 2016.

Table 11.5 Materiality of shared asset revenues for the 2016–2020 regulatory control period ($ million, nominal)

	2016	2017	2018	2019	2020
Forecast unregulated revenue from shared assets	3.0	3.0	3.1	3.2	3.3
Smoothed revenue (prior to shared asset reduction)	282.9	307.7	316.8	326.2	335.9
Materiality percentage	1.05	0.98	0.98	0.98	0.97
Greater than 1 per cent materiality threshold?	Yes	No	No	No	No

Source: CitiPower

11.4.7 Estimated cost of corporate income tax

We accept the AER's method for estimating corporate income tax, but reject the value of imputation credits (gamma). The divergence between our revised estimated cost of corporate income tax and the AER's preliminary determination is primarily attributable to our revised regulatory proposal in respect of gamma and various building blocks that have a consequential effect on the tax calculation.

Our revised proposal in respect of corporate income tax is set out in the table below.

Table 11.6 Estimated cost of corporate income tax ($ million, nominal)

	2016	2017	2018	2019	2020
Regulatory proposal	25.9	25.5	25.4	25.6	28.2
Preliminary determination	15.8	14.3	13.5	14.3	14.9
Revised regulatory proposal	26.8	26.9	24.7	24.7	25.6

Source: CitiPower

It is however unclear to us what the AER means by the following comments in its preliminary determination concerning its approach to calculating tax remaining lives at the next price reset:

> *Having established the remaining tax asset lives to 1 January 2016 for this determination process, we consider that when rolling forward these remaining tax asset lives to 1 January 2020 at the next reset our preferred weighted average method should be used.*[1044]

We consider that the method used to roll forward the tax asset base from 1 January 2016 to 1 January 2021 at the next price reset must be consistent with the method used to roll forward the forecast tax asset base over the 2016–2020 regulatory control period, except that the 1 January 2016 opening tax asset base should be updated to reflect actual 2015 capital expenditure and actual 2016–2020 capital expenditure ought to be used to roll forward the tax asset base instead of forecast 2016–2020 capital expenditure. We consider it appropriate to roll

[1044] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 8-13.

forward the tax remaining asset lives by decreasing the values calculated by the AER as at 1 January 2016 by one year for each subsequent regulatory year in the 2016–2020 regulatory control period.

11.5 Our revised regulatory proposal

For the purposes of clause 6.4.3(a)(6) and clause 6.4.3(b)(6) of the Rules, there are no other revenue increments or decrements to be carried forward from the previous regulatory control period.

The previous sections set out our proposed building blocks. The building blocks are used to derive our proposed unsmoothed annual revenue requirement for standard control services which are shown in the table below.

Our proposed smoothed revenue is based on revenue X factors which have been calculated so that smoothed revenue relatively closely follows the underlying building block costs (net of efficiency scheme revenue increments or decrements). Further, revenue X factors to be included below, which relate to standard control services, are designed to equalise (in terms of NPV) the revenue to be earned by us from the provision of standard control services over the 2016–2020 regulatory control period with our proposed total revenue requirement for that period. We have estimated inflation in accordance with chapter 9 of this revised regulatory proposal.

Table 11.7 Revenue requirement ($ million, nominal)

	2016	2017	2018	2019	2020
Return on assets	108.4	115.7	125.0	133.1	139.5
Regulatory depreciation	58.2	58.0	62.6	66.9	72.8
Operating expenditure	90.1	93.4	103.0	107.7	110.1
Demand management incentive allowance (DMIA)	0.2	0.2	0.2	0.2	0.2
EBSS efficiency carryover	-0.1	-2.8	1.1	-1.4	-
S factor true up	1.6	-	-	-	-
Shared asset revenue reduction	-0.3	-	-	-	-
Corporate income tax	26.8	26.9	24.7	24.7	25.6
Unsmoothed revenue requirement	284.9	291.4	316.6	331.1	348.2
Smoothed revenue requirement	282.9	307.8	316.9	326.3	336.0
Forecast CPI %	2.50	2.50	2.50	2.50	2.50
Revenue X factor (%)[1045]	**6.75**	**-6.16**	**-0.45**	**-0.45**	**-0.45**

Source: CitiPower

[1045] A positive revenue X factor means a real revenue decrease and a negative revenue X factor means a real revenue increase.

11.6 Control mechanisms

We accept the preliminary determination position to adopt the revenue cap form of price control and formulae that give effect to the control mechanism as set out in the Framework and Approach Paper.

12 Incentive schemes

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12 Incentive schemes

Service target Performance Incentive Scheme (STPIS)

We maintain our position that it is necessary to adjust the reliability targets to take account of the lower Value of Customer Reliability (**VCR**). The VCR is the key determinant of the value of the incentive rewards and penalties under the STPIS. Due to the significant reduction in the VCR, our incentive rates have reduced by approximately 60 per cent for the Central Business District (**CBD**) network and 30 per cent for the urban network.

As a direct result, the scheme will provide weaker incentives to mitigate deteriorations in reliability or seek reliability improvement opportunities. Many projects required to maintain current network reliability performance will no longer meet the Regulatory Investment Test and/or will not provide net economic benefits to consumers. Consequently, these projects will not proceed and over time reliability will decline. It would be inconsistent with the National Electricity Rules (**Rules**) for distributors to incur STPIS penalties resulting from the gradual decline in reliability, which is caused by the lower VCR, as the penalties would exceed the benefits to customers of maintaining reliability.

We agree with the Australian Energy Regulator (**AER**) that the impact on reliability will occur over time. We have therefore proposed a transition period of 60 years until the full effect of the lower VCR translates into lower reliability outcomes.

We maintain our position that the revenue at risk should be reduced to 2.5 per cent. We are the best performing network and deliver a high level of reliability to our customers. Our network has now reached its optimal level of underlying reliability performance and there is limited opportunity for further improvement. A revenue at risk of 2.5 per cent is consistent with the Rules to ensure the benefits to consumers warrant the reward or penalty available under the STPIS. A higher revenue at risk creates a real risk of consumers incurring windfall financial gains and losses that reflect the impact on reliability of external factors and not changes in underlying reliability performance.

Efficiency Benefit Sharing Scheme (EBSS)

We accept the AER's preliminary determination to apply the EBSS in the 2016–2020 regulatory control period, with exclusions for debt raising costs, demand management incentive allowance and Guaranteed Service Level (**GSL**) payments. However, we dispute the AER's proposed exclusion for losses on scrapping of assets because this is not an operating expenditure item and therefore is not relevant to the EBSS.

Demand Management Incentive Scheme (DMIS)

We maintain our view that the DMIS should allow distributors to seek pre-approval from the AER for funding above the capped amount. Without sufficient research and development funding for the exploration of new and untested alternatives, there is a real risk that opportunities are not taken up by distributors.

Innovations in demand management have the potential to replace or defer network augmentation and therefore promote efficient investment in electricity services for the long term interests of consumers of electricity. Our proposal to provide an opportunity for further funding above the ex-ante cap is therefore consistent with the National Electricity Objective (**NEO**).

We acknowledge submissions made by stakeholders seeking further information on the types of projects that would be funded through additional DMIS funding. We consider this is best addressed by requiring the AER to consult stakeholders on a distributor's proposals for additional funding before approval.

Capital Expenditure Sharing Scheme (CESS) and Fire Factor (F-Factor) Scheme

We accept the AER's preliminary determination to apply the CESS and F-factor scheme.

12.1 Service target performance incentive scheme

12.1.1 Rule requirements

Clause 6.6.2(b)(3) of the Rules sets out the factors the AER must take into account when developing and implementing the STPIS, including:

> *(i) the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for Distribution Network Service Providers; and*
>
> *(ii) any regulatory obligation or requirement to which the Distribution Network Service Provider is subject; and*
>
> *(iii) the past performance of the distribution network; and*
>
> *(iv) any other incentives available to the Distribution Network Service Provider under the Rules or a relevant distribution determination; and*
>
> *(v) the need to ensure that the incentives are sufficient to offset any financial incentives the Distribution Network Service Provider may have to reduce costs at the expense of service levels; and*
>
> *(vi) the willingness of the customer or end user to pay for improved performance in the delivery of services; and*
>
> *(vii) the possible effects of the scheme on incentives for the implementation of non-network alternatives.*

These factors also form the objectives set out in clause 1.5 of the STPIS Guideline.

Clause 2.2 of the STPIS Guideline requires that distributors proposing variations to the scheme must demonstrate how the proposed variation is consistent with the objectives of the scheme.

12.1.2 Initial regulatory proposal

We proposed applying the STPIS in accordance with the STPIS Guideline subject to the following variations:

- the incentive rates for the reliability parameters are calculated based on the relevant VCR values from Australian Energy Market Operator's (**AEMO's**) 2014 report;
- the reliability targets for unplanned System Average Interruption Duration Index (**SAIDI**) and unplanned System Average Interruption Frequency Index (**SAIFI**), for each network segment, are calculated based on the historical five year average performance over the period 2010 to 2014 plus an adjustment to account for the deterioration in network performance that will occur as a result of the significant reduction in the VCR used for network planning purposes and the STPIS incentive rates;
- the Momentary Average Interruption Frequency Index (**MAIFI**) not be included in the STPIS;
- the definition of SAIFI is amended to include interruptions of three minutes or more; and
- capping the total revenue at risk for all s-factor parameters to +/- 2.5 per cent, including +/- 2 per cent for the reliability parameters and +/- 0.5 per cent for the customer service parameter.

We proposed no variations from the STPIS Guideline in relation to calculating the telephone answering target or incentive rates. We proposed no additional customer service parameters.

Our proposed STPIS targets and incentive rates are set out in the following tables.

Table 12.1 STPIS targets and incentive rates

Parameter	Segment	Proposed targets	Proposed incentive rates
Unplanned SAIDI	CBD	10.02	0.05%
Unplanned SAIDI	Urban	34.01	0.05%
Unplanned SAIFI	CBD	0.14	2.85%
Unplanned SAIFI	Urban	0.50	3.23%
Telephone answering	Network	75.31%	-0.04%

Source: CitiPower

The following sections set out the AER's preliminary determination on our proposed variations to the STPIS and our revised regulatory proposal for the 2016–2020 regulatory control period.

12.1.3 Incentive rates

AER preliminary determination

The AER's preliminary determination accepted the use of AEMO's 2014 VCRs to calculate the reliability incentive rates. The AER escalated AEMO's 2014 VCR by one year of Consumer Price Index (**CPI**) inflation.

The AER's preliminary determination included an error in the calculation of the reliability incentive rates. To calculate the incentive rates the AER applied total energy forecasts over the 2016–2020 regulatory control period instead of average annual energy forecasts as specified in Appendix B of the STPIS Guideline. Following notification of this error, the AER has advised us the calculation will be corrected in the final determination and will be applied for the 2016 regulatory year.[1046]

The AER's preliminary determination accepted our proposed incentives rates for telephone answering.

Our revised regulatory proposal

We accept the AER's preliminary determination to apply AEMO's 2014 VCRs escalated by one year of CPI inflation to calculate the reliability incentive rates. We have therefore calculated our incentive rates for the revised regulatory proposal in accordance with the STPIS Guideline and applying the AEMO 2014 VCRs escalated for one year of CPI inflation.

We accept the AER's preliminary determination to accept our proposed telephone answering incentive rate and have applied this for our revised regulatory proposal.

12.1.4 Targets

AER preliminary determination

The AER's preliminary determination rejected our proposal to adjust the reliability targets to take account of the impact on reliability due to the lower VCRs, because:[1047]

- the VCR has varied between years but there has been no net movement in values between the previous (2006–2010 and 2011–2015) regulatory periods and the 2016–2020 regulatory control period;

[1046] AER, *Errors in distribution determination for CitiPower regarding STPIS*, November 2015.

[1047] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p.11-16.

- there appears to be little, no immediate or no close correlation between VCR and reliability outcomes; and
- an adjustment to the targets was not applied when the VCR changed between the 2006–2010 and 2011–2015 regulatory control periods.

The AER's preliminary determination recalculated our proposed telephone answering target.

Our response to the AER’s preliminary determination

<u>Adjustment to targets for reduction in VCR</u>

We dispute the AER's preliminary determination to reject our proposed adjustment to the reliability targets to account for the impact of the lower VCR.

The STPIS is designed to provide financial incentives for distributors to plan network projects to:

- improve reliability performance where the incentive reward is higher than the project costs; and
- mitigate deteriorations in reliability where the incentive penalty is greater than the project costs.

The VCR is the key determinant of the value of the incentive rewards and penalties. Due to the significant reduction in the VCR, our incentive rates have reduced by approximately 60 per cent for our CBD network and 30 per cent for our urban network relative to the 2011–2015 regulatory control period.

As a direct result the scheme will provide weaker incentives to mitigate deteriorations in reliability and seek reliability improvement opportunities. Further, many projects required to maintain current network reliability performance will no longer meet the Regulatory Investment Test - Distribution (**RIT-D**) and/or will not provide net economic benefits to consumers. Consequently, these projects will not proceed.

Customers will therefore gradually receive a lower level of network reliability performance over time. This outcome is a fair reflection of the lower value that customers place on reliability as indicated by the reductions in the VCR.

When implementing the STPIS, the Rules require the AER to take into account (clause 6.6.2(b)(3)):

- the need to ensure the benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme; and
- any regulatory obligation or requirement to which the distributor is subject.

It would be inconsistent with the Rules for the penalty, for not undertaking projects that no longer meet the net benefits tests under either the STPIS or RIT-D, to exceed the benefits to customers of those projects.

We agree with the AER that there will not be an immediate impact on reliability. This is why we proposed a 40 year transition period to targets that fully reflect the lower incentive rates. We have increased our proposed transition period from 40 years to 60 years for our revised regulatory proposal. This reduces the magnitude of the adjustment relative to our initial regulatory proposal and allows a longer period for the change in the STPIS incentive rates to have full effect on reliability performance.

We are particularly concerned about the impact on network planning resulting from volatility in the VCRs. The VCR is a key input into network planning, including augmentation, replacement and maintenance expenditure. Instability in the VCR does not promote efficient investment decisions and is not in the long term interests of consumers. This is because investments made under the prevailing VCR can subsequently become uneconomic if the VCR is reduced. We are undertaking long term investment decisions spanning roughly 50 years. A reasonable level of stability in the VCRs is therefore essential for efficient network planning. Further, any changes in the VCR should be gradual, reflecting the relatively slow pace of change in customer preferences regarding the value of reliability. It is concerning, in this case, that the significant change in the VCR appears to be driven more by changes in survey approach than actual customer preferences.

Adjustments to targets for Victorian Government’s bushfire initiatives

Our reliability targets should not be adjusted to reflect theoretical improvements to reliability from the Victorian Government’s bushfire initiatives, including the powerline relocation program, the installation of Rapid Earth Fault Current Limiters (**REFCLs**) and changed standards for asset construction and replacement in declared areas.

The obligations relating to the replacement of powerlines in high bushfire risk areas, upgrade of automatic circuit reclosers on Single Wire Earth Return (**SWER**) lines and the installation of RECFLs are not expected to be relevant to our network. Therefore we expect no reliability impact from these programs in our network area during the 2016–2020 regulatory control period.

Notwithstanding the above, should the AER consider making such an adjustment, we would expect to be consulted on the nature, quantification and implementation prior to the making of the final determination, in accordance with section 16(1)(b) of the National Electricity Law.

Our revised regulatory proposal

We maintain our position that the reliability targets should be adjusted to account for the lower VCRs as this is more consistent with the Rules and objectives of the STPIS scheme. We have maintained our methodology for calculating the adjustment to the STPIS targets to account for the change in the VCR. However we have increased the transition period from 40 years to 60 years.

We accept the AER's preliminary determination in relation to the telephone answering target and have applied this value for our revised regulatory proposal.

12.1.5 Revenue at risk

AER preliminary determination

The AER's preliminary determination rejected our proposal to cap the revenue at risk to 2.5 per cent, instead the AER retained the five per cent revenue at risk set out in the STPIS Guideline. The AER considered that our proposal to reduce the revenue at risk was directly related to the lower VCRs. Therefore, the AER, did not accept our proposal because:[1048]

- the VCR has varied between years but there has been no net movement in values between the previous (2006–2010 and 2011–2015) regulatory periods and the 2016–2020 regulatory control period;
- there appears to be little, no immediate or no close correlation between VCR and reliability outcomes; and
- an adjustment to the targets was not applied when the VCR changed between the 2006–2010 and 2011–2015 regulatory control periods.

Our response to the AER’s preliminary determination

We dispute the AER's preliminary determination to apply five per cent revenue at risk. The AER has mis-characterised our reasons for proposing a lower revenue at risk as being a result of the lower VCR. This is not the case.

We are the best performing network in the National Electricity Market (**NEM**) and deliver a high level of reliability to our customers. Our network has now reached its optimal level of underlying reliability performance level. It is therefore increasingly difficult to economically justify projects aimed at further improving underlying reliability performance.

[1048] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p.11-16.

Observed and expected variation in reliability performance between years is primarily a result of unusual weather and other external events. These events are external to management control and it is not cost effective for us to invest in additional mitigation activities which would increase costs to customers.

When implementing the STPIS, the AER must take into account the need to ensure that the benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme (Rules clause 6.6.2(b)(3)(i)). It would be inconsistent with the Rules for the AER to set a limit on the revenue at risk which exceeds the value of the benefits customers can receive from the scheme. Given the limited opportunity to improve the underlying reliability performance of our network, a five per cent revenue at risk creates a real risk of windfall gains and losses occurring that are not reflective of true improvements in reliability, instead simply reflecting annual variations due to external events. Therefore a lower revenue at risk of 2.5 per cent is more consistent with the Rules to ensure the benefits to consumers warrant the reward or penalty available under the scheme.

Our revised regulatory proposal

For our revised regulatory proposal, we maintain our position that the revenue at risk be reduced to 2.5 per cent for the 2016–2020 regulatory control period, inclusive of two per cent for the reliability component and 0.5 per cent for the customer services component.

12.1.6 Exclusion of MAIFI from the scheme

AER preliminary determination

The AER's preliminary determination rejected our proposal to exclude MAIFI from the STPIS on the basis that:[1049]

- MAIFI is measurable and there is no other basis set out in the STPIS Guideline to remove MAIFI;
- MAIFI has an impact on customers; and
- excluding MAIFI from the scheme must be subject to a general review of the scheme and requires extensive consultation.

Our response to the AER’s preliminary determination

We do not agree with the AER's preliminary determination to include MAIFI in the STPIS.

There are few cost effective technical solutions available for us to improve MAIFI and those solutions that are available have already been taken up. The new technologies which are available for improving short duration interruptions enable interruptions to be reduced to less than three minutes but not less than one minute.

Notwithstanding, for the 2016–2020 regulatory control period, we accept the AER's preliminary determination to include MAIFI in the STPIS. However, for the reasons discussed above, we strongly encourage the AER to review the inclusion of MAIFI in its review of the STPIS Guideline to be completed by mid-2017.

Further, we seek clarification that MAIFIe will apply rather than MAIFI, consistent with the AER's preliminary determination for United Energy and current reporting practices.

Our revised regulatory proposal

For our revised regulatory proposal, we propose MAIFIe be applied and calculated in accordance with the STPIS Guideline.

[1049] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 11-22.

12.1.7 Amendment to the definition of SAIFI

AER preliminary determination

The AER's preliminary determination rejected our proposal to amend the definition of SAIFI to an interruption of three minutes duration or more, because it considered:[1050]

- doing so would alter the operation of the scheme; and
- changes of such magnitude should be consulted on with all stakeholders.

Our response to the AER's preliminary determination

We do not agree with the AER's preliminary determination. Amending the definition of SAIFI to exclude outages of less than three minute duration would create stronger incentives for distributors to invest in automation technologies that enable faster restoration times. This is because there is a greater range of cost effective options in the design of distribution automation systems for achieving restoration times less than three minutes, compared with achieving restoration times less than one minute.

Further, the Australian Energy Market Commission (**AEMC**) recommended that the definition of SAIFI be amended to exclude outages of less than three minutes.[1051] As noted by the AEMC, the current Institute of Electrical and Electronic Engineering (**IEEE**) standard defines a sustained interruption as being greater than five minutes and the UK economic regulator, the Office of Gas and Electricity Markets (**Ofgem**) changed its definition of a sustained interruption from one to three minutes in order to provide an incentive for distribution automation systems that could speed up restoration of supply for some customers.[1052]

Notwithstanding, for the 2016–2020 regulatory control period, we accept the AER's preliminary determination to retain the definition of SAIFI in accordance with the STPIS Guideline, as an interruption with duration of one minute or more. However, for the reasons stated above, we strongly encourage the AER to review the definition of SAIFI in its review of the STPIS Guideline to be completed by mid-2017.

Our revised regulatory proposal

For our revised regulatory proposal, we propose SAIFI be defined in accordance with the STPIS Guideline for the 2016–2020 regulatory control period.

12.1.8 Our revised regulatory proposal

The following table sets out our revised regulatory proposal STPIS targets and incentive rates.

[1050] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 11-23.

[1051] CP PUBLIC APP H.2 - AEMC, *Review of distribution reliability measures*, p. 9.

[1052] CP PUBLIC APP H.2 - AEMC, *Review of distribution reliability measures*, p. 13.

Table 12.2 STPIS targets and incentive rates

Parameter	Segment	Proposed targets	Proposed incentive rates
Unplanned SAIDI	CBD	9.726	0.048%
Unplanned SAIDI	Urban	33.573	0.049%
Unplanned SAIFI	CBD	0.137	3.036%
Unplanned SAIFI	Urban	0.495	3.433%
Unplanned MAIFI	CBD	0.005	0.243%
Unplanned MAIFI	Urban	0.152	0.275%
Telephone answering	Network	75.32%	-0.040%

Source: *CP STPIS targets*.xlsx and *CP STPIS incentive rates*.xlsx

12.2 Efficiency benefit sharing scheme

12.2.1 Rule requirements

Clause 6.5.8(c) of the Rules sets out the factors the AER must take into account when developing and implementing the EBSS, including:

> *(1) the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for Distribution Network Service Providers;*
>
> *(2) the need to provide Distribution Network Service Providers with a continuous incentive, so far as is consistent with economic efficiency, to reduce operating expenditure ;*
>
> *(3) the desirability of both rewarding Distribution Network Service Providers for efficiency gains and penalising Distribution Network Service Providers for efficiency losses;*
>
> *(4) any incentives that Distribution Network Service Providers may have to capitalise expenditure; and*
>
> *(5) the possible effects of the scheme on incentives for the implementation of non-network alternatives.*

Clause 1.4 of the EBSS Guideline provides for the AER to make adjustments when calculating carry over amounts, to, among other things:

> *Adjust forecast opex to add any approved revenue increments or subtract any approved revenue decrements made after the initial regulatory determination for regulatory control period n. This may include approved pass through amounts or opex for contingent projects.*
>
> *Adjust actual opex incurred in regulatory control period n to add capitalised opex that has been excluded from the Regulatory Asset Base.*
>
> *Exclude categories of opex not forecast using a single year revealed cost approach for the regulatory control period n + 1 where doing so better achieves the requirements of clauses 6.5.8 and 6A.6.5 of the NER.*

12.2.2 Initial regulatory proposal

We proposed applying the EBSS in accordance with the AER's EBSS Guideline for the 2016–2020 regulatory control period, subject to the exclusion of the following categories of operating expenditure:

- debt raising costs;

- self-insurance costs;
- superannuation costs for defined benefits and retirement schemes;
- the Demand Management Incentive Allowance (**DMIA**);
- Guaranteed Service Level (**GSL**) payments; and
- approved pass throughs.

We also proposed:

- there should be an adjustment for provisions and any changes in capitalisation policy; and
- the benchmark allowance should be adjusted for costs of meeting new obligations introduced after the final determination.

12.2.3 AER's preliminary determination

The AER's preliminary determination accepted our proposal to apply the EBSS in the 2016–2020 regulatory control period in accordance with the EBSS Guideline.

In relation to the exclusion of expenditure items for the purposes of calculating the EBSS carry over amounts for the 2016–2020 regulatory control period, the AER's preliminary determination:[1053]

- accepted our proposed exclusions for debt raising costs, DMIA and GSL payments;
- rejected our proposal to exclude superannuation for defined benefits and self-insurance costs; and
- included an additional exclusion for losses of the scrapping of assets in response to a proposal by Jemena.

The AER also stated that it will adjust forecast operating expenditure to:[1054]

- add or subtract any revenue increments or decrements made after the initial regulatory determination, including pass through amounts;
- adjust actual operating expenditure for capitalised operating expenditure that has been excluded from the regulatory asset base; and
- exclude categories of operating expenditure not forecast using a single revealed cost approach for the regulatory control period beginning in 2021 where doing so better achieves the requirements of clause 6.5.8 of the Rules.

12.2.4 Our response to the AER's preliminary determination

We accept the AER's preliminary determination to exclude debt raising costs, DMIA and GSL payments. We also accept the AER's preliminary determination not to exclude superannuation for defined benefits and self-insurance costs.

We do not accept the AER's preliminary determination to exclude losses on scrapping of assets because, as discussed in chapter 6, losses on scrapping of assets is not an operating expenditure item and therefore is not relevant to the EBSS.

1053 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, pp. 9-11 to 9-12.

1054 AER, *Preliminary decision, CitiPower distribution determination 2016–2020*, October 2015, p. 9-12.

12.2.5 Our revised regulatory proposal

For our revised regulatory proposal, we propose the EBSS apply with exclusions for debt raising costs, DMIA and GSL payments only.

12.3 Capital expenditure sharing scheme

12.3.1 Rule requirements

Clause 6.4A of the Rules sets out the objectives of the CESS and the obligations on the AER in relation to the making of the CESS Guideline, including:

> *(1) any capital expenditure sharing schemes developed by the AER in accordance with clause 6.5.8A, and how the AER has taken into account the capital expenditure sharing scheme principles in developing those schemes;*
>
> *(2) the manner in which it proposes to make determinations under clause S6.2.2A(a) if the overspending requirement is satisfied;*
>
> *(3) the manner in which it proposes to determine whether depreciation for establishing a regulatory asset base as at the commencement of a regulatory control period is to be based on actual or forecast capital expenditure;*
>
> *(4) the manner in which it proposes to make determinations under clause S6.2.2A(i) if the margin requirement is satisfied; and*
>
> *(5) the manner in which it proposes to make determinations under clause S6.2.2A(j) if the capitalisation requirement is satisfied; and*
>
> *(6) how each scheme and proposal referred to in subparagraphs (1) to (5), and all of them taken together, are consistent with the capital expenditure incentive objective.*

12.3.2 Initial regulatory proposal

We proposed applying the CESS in accordance with the CESS Guideline for the 2016–2020 regulatory control period, with no amendments.

We also supported the use of forecast depreciation to establish the opening RAB value as at 1 January 2021 and to apply the CESS on a net basis, because this is the cost borne by customers.

12.3.3 AER’s preliminary determination

The AER's preliminary determination accepted our proposal to apply the CESS in accordance with the CESS Guideline.

12.3.4 Our revised regulatory proposal

We accept the AER's preliminary determination. Our revised regulatory proposal therefore applies the CESS in accordance with the CESS Guideline.

12.4 Demand management incentive allowance

12.4.1 Rule requirements

Clause 6.6.3(b) of the Rules requires sets out the factors the AER must have regard to in developing and implementing a DMIS, including:

(1) the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme for Distribution Network Service Providers;

(2) the effect of a particular control mechanism (i.e. price – as distinct from revenue – regulation) on a Distribution Network Service Provider's incentives to adopt or implement efficient non-network alternatives;

(3) the extent the Distribution Network Service Provider is able to offer efficient pricing structures;

(4) the possible interaction between a demand management and embedded generation connection incentive scheme and other incentive schemes under clauses 6.5.8, 6.5.8A, 6.6.2 and 6.6.4;

(5) the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme; and

(6) the effect of classification of distribution services, as determined in accordance with clause 6.2.1, on a Distribution Network Service Provider's incentive to adopt or implement efficient Embedded Generator connections.

12.4.2 Initial regulatory proposal

In accordance with Part A of the DMIS, we proposed that the ex-ante capped allowance of $1 million over the regulatory control period continue to be provided as additional fixed revenue for each year of the regulatory control period.

We also proposed an amendment to the scheme which allows for further funding above the capped amount, on the proviso the AER pre-approves all proposed DMIS initiatives in excess of the capped amount. We consider a capped DMIS constrains the ability of distributors to invest in innovation. Given the rapid rate of technological change, a well-functioning DMIS should facilitate our ability to respond and realise greater benefits for consumers.

12.4.3 AER's preliminary determination

The AER preliminary determination accepted our proposal to apply Part A of the DMIS based on a fixed capped allowance of $1 million over the 2016–2020 regulatory control period.

The AER preliminary determination rejected our proposal to allow distributors to seek pre-approval from the AER for DMIS funding above the capped amount because it considered that:[1055]

- while the scheme requires reform, any changes to the scheme should be considered at the whole industry level through the scheduled review in 2016;
- the move to a revenue cap form of control will removes any disincentives for demand management initiatives; and
- the RIT-D requires consideration of non-network alternatives.

12.4.4 Our response to the AER's preliminary determination

We accept the AER's preliminary decision in relation to the value of the fixed capped allowance of $1 million over the 2016–2020 regulatory control period.

We disagree with the AER's preliminary determination not to allow distributors to seek additional DMIS funding.

[1055] AER, *Preliminary Decision, CitiPower distribution determination 2016–20*, October 2015, p. 12-9.

We agree the introduction of a revenue cap removes disincentives to invest in non-network alternatives and the RIT-D requirements allows for the consideration of non-network alternatives that are available at the time. However, neither of these removes the constraint on distributors' incentives to invest in research and development of non-network alternatives, which is created by the cap on the DMIA.

Without sufficient research and development funding for the exploration of new and untested alternatives, there is a real risk that opportunities are not taken up by distributors. Notably, Ofgem has introduced an Electricity Network Innovation Competition which provides up to £81 million per annum of additional funding for innovations that will help all networks understand what they need to do to provide environmental benefits, cost reductions and security of supply.[1056]

We acknowledge submissions made by stakeholders seeking further information on the types of projects that would be funded through additional DMIS funding. We consider that this is best addressed by requiring the AER to consult stakeholders on a distributor's proposal to seek additional funding under the DMIS before approval.

Enabling further funding to be provided, following pre-approval by the AER and stakeholder consultation, facilitates exploration of demand management innovations in a timely manner and ensures potential efficiency enhancing innovations are not unduly constrained or deferred due to an arbitrary cap. Innovations in demand management have the potential to replace or defer network augmentation and therefore promote efficient investment in electricity services for the long term interests of consumers of electricity. Our proposal to provide an opportunity for further funding above the cap is therefore consistent with the NEO.

Notwithstanding, should the AER's final determination not allow distributors to seek additional DMIS funding, we strongly encourage the AER to review this decision as part of its review of the DMIS and to ensure any changes take effect before the next round of regulatory determinations.

12.4.5 Our revised regulatory proposal

We accept the AER's preliminary determination in relation to the fixed capped allowance of $1 million over the 2016–2020 regulatory control period. We therefore continue to propose a fixed allowance of $1 million over the 2016–2020 regulatory control period.

We maintain our position that distributors should be able to seek AER pre-approval for additional funding above the capped amount. We propose the AER be required to consult stakeholders on distributors' proposals for additional funding before it pre-approves the funding.

12.5 F-factor scheme

12.5.1 Rule requirements

The *F-factor Scheme Order 2011* made under the *National Electricity (Victoria) Act 2005* sets out the operation of the F-factor scheme and places obligations on the AER in relation to making F-factor scheme determinations.

12.5.2 Initial regulatory proposal

For the 2016–2020 regulatory control period, we accepted the AER's position in the Framework and Approach paper to apply the Victorian Government's F-factor scheme, including maintaining the incentive rate of $25,000 per fire.

[1056] Ofgem, *Electricity Network Innovation Competition*, December 2015, https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/electricity-network-innovation-competition, accessed on 9 December 2015.

12.5.3 AER's preliminary determination

The AER's preliminary determination applies the F-factor scheme for the 2016–2020 regulatory control period based on the following parameters:

- target of 25.8 fires per annum based on the average performance over the past five regulatory years; and
- incentive rate of $25,000 per fire.

12.5.4 Our revised regulatory proposal

We accept the AER's preliminary determination. Our revised regulatory proposal therefore proposes the F-factor scheme apply based on the following parameters:

- target of 25.8 fires per annum based on the average performance over the past five regulatory years; and
- incentive rate of $25,000 per fire.

12.6 Small-scale incentive scheme

12.6.1 Rule requirements

Clause 6.6.4 of the Rules provides that the AER may, in accordance with the distribution consultation procedures, develop and publish a small-scale incentive scheme that provides distributors with incentives to provide standard control services in a manner that contributes to the achievement of the NEO.

The AER has not published a small-scale incentive scheme.

12.6.2 Initial regulatory proposal

For the 2016–2020 regulatory control period, we did not propose any small-scale incentive schemes.

12.6.3 AER's preliminary determination

The AER's preliminary determination does not propose applying any small-scale incentive schemes.

12.6.4 Our revised regulatory proposal

We accept the AER's preliminary determination. Our revised regulatory proposal therefore proposes no small-scale incentive schemes be applied.

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13 Managing uncertainty

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13 Managing uncertainty

This section of our revised regulatory proposal responds to the Australian Energy Regulator's (**AER's**) preliminary determination with respect to the:

- additional pass through events that are to apply for the 2016–2020 regulatory control period in accordance with clause 6.5.10 of the National Electricity Rules (**Rules**) (**nominated pass through events**); and
- application of the pass through mechanism in clause 6.6.1 of the Rules to alternative control services.

Nominated pass through events

In our regulatory proposal, we proposed as nominated pass through events: an insurance event, an insurer credit risk event, a natural disaster event, a terrorism event, an ending of the metering derogation event, a multiple trading relationships event and a retailer failure event.

In its preliminary determination, the AER accepted an insurance cap event, insurance credit risk event, natural disaster event, terrorism event and retailer failure event as nominated pass through events. However, the AER amended the definitions of those events. The AER rejected the ending of the metering derogation event and the multiple trading relationships event as nominated pass through events.

In our revised regulatory proposal, we do not wholly accept the AER's preliminary determination on the definitions of the insurance cap event, insurance credit risk event, natural disaster event, terrorism event and retailer failure event. Accordingly, we propose revisions to the AER's definitions of those events. In addition, we have revised the name of the retailer failure event, to refer to it as a retailer insolvency event (consistent with the retailer insolvency event in the Rules).

We accept the AER's preliminary determination that an ending of metering derogation event and a multiple trading relationships event should not apply as nominated pass through events in the 2016–2020 regulatory control period.

Application to alternative control services

Consistent with our regulatory proposal, we accept the AER's decision in its preliminary determination to approve the application of nominated pass through events to alternative control services. We also accept the AER's decision to reject our proposal to modify the definition of 'materially' applicable to pass throughs in respect of alternative control services, and to vary the control mechanisms for alternative control services so that approved pass through amounts would be recoverable from customers of alternative control services.

For the avoidance of doubt, the AER should specify in its final determination in connection with its constituent decision on the form of the control mechanism for alternative control services under clause 6.12.1(12) of the Rules that the pass through mechanism in clause 6.6.1 of the Rules (including all defined pass through events, being events prescribed by the Rules and those specified in the distribution determination) applies to alternative control services. Alternatively, if the AER considers this unnecessary, the AER should expressly confirm that this is because it shares our understanding that the correct legal construction of the Rules is that the Rules in and of itself applies clause 6.6.1 to alternative control services. Further, we request the AER to amend the description of the B^t term in the revenue cap formula for standard control services to make specific reference to 'direct control services' in describing the AER approved pass through amounts in that term.

13.1 Rule requirements

Clause 6.5.10(a) of the Rules provides that a building block proposal may include a proposal as to the events that should be defined as pass through events under clause 6.6.1(a1)(5) having regard to the nominated pass through event considerations.

Clause 6.12.1(14) of the Rules in turn provides that one of the constituent decisions on which the distribution determination is predicated is a decision on the additional pass through events that are to apply for a regulatory control period in accordance with clause 6.5.10. Clause 6.5.10(b) requires the AER, in making this constituent decision, to take into account the nominated pass through event considerations.

The 'nominated pass through event considerations' are relevantly defined in chapter 10 of the Rules to be:

- whether the event proposed is an event covered by a category of pass through event specified in clause 6.6.1(a1)(1) to (4);
- whether the nature or type of event can be clearly identified at the time the determination is made for the service provider;
- whether a prudent service provider could reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event;
- whether the relevant service provider could insure against the event, having regard to:
  - the availability (including the extent of availability in terms of liability limits) of insurance against the event on reasonable commercial terms; or
  - whether the event can be self-insured on the basis that:
    - it is possible to calculate the self-insurance premium; and
    - the potential cost to the relevant service provider would not have a significant impact on the service provider’s ability to provide network services; and
- any other matter the AER considers relevant and which the AER has notified network service providers is a nominated pass through event consideration.

In addition, the AER must:

- perform or exercise a function or power under the National Electricity Law (**Law**) or the Rules that relates to the making of a distribution determination in a manner that will or is likely to contribute to the achievement of the national electricity objective (**NEO**);[1057] and
- in making a distribution determination, if there are two or more decisions that will or are likely to contribute to the achievement of the NEO, the AER must make the decision that it is satisfied will or is likely to contribute to the achievement of the NEO to the greatest degree.[1058]

Finally, the AER must take into account the revenue and pricing principles when exercising a discretion in making those parts of a distribution determination relating to direct control network services.[1059] The revenue and pricing principles are set out in section 7A of the Rules and relevantly include:

[1057] NEL, section 16(1)(a) and section 2(1) definition of 'AER economic regulatory function or power'.

[1058] NEL, section 16(1)(d) and sections 2(1) and 71A definitions of 'reviewable regulatory decision'.

[1059] NEL, section 16(2)(a).

(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in–

(a) providing direct control network services; and

(b) complying with a regulatory obligation or requirement or making a regulatory payment.

(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes–

(a) efficient investment in a distribution system … with which the operator provides direct control network services; and

(b) the efficient provision of electricity network services; and

(c) the efficient use of the distribution system … with which the operator provides direct control network services.

…

(5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

The revenue and pricing principles in section 7A can be taken to be consistent with and to promote the NEO.

13.2 Nominated pass through events

13.2.1 Initial regulatory proposal

In our regulatory proposal, we proposed the following events to be approved as part of our distribution determination, to apply as nominated pass through events for the 2016–2020 regulatory control period:

- an insurance event;
- an insurer credit risk event;
- a natural disaster event;
- a terrorism event;
- an ending of the metering derogation event;
- a multiple trading relationships event; and
- a retailer failure event.

Our proposed definitions for each of these proposed nominated pass through events are set out in the following table.

Table 13.1 Our proposed nominated pass through events

Proposed event	Proposed definition
Insurance event	An 'insurance event' occurs if: (a) the distributor makes a claim on a relevant insurance policy; and (b) the distributor incurs costs beyond the relevant policy limit. For the purposes of this insurance event: (a) the relevant policy limit is the distributor’s actual policy limit at the time of the event that gives rise to the claim; and (b) a relevant insurance policy is an insurance policy held during the 2016–2020 regulatory control period or a previous regulatory control period in which CitiPower was regulated.
Insurer credit risk event	An insurance credit risk event occurs if as a result of the insolvency of an insurer, the distributor: (a) incurs higher or lower costs for insurance premiums; (b) in respect of a claim for a risk that would have been insured by the distributor’s insurers, is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the relevant policy; and/or (c) incurs additional costs associated with self funding an insurance claim, which, would have otherwise been covered by the insolvent insurer.
Natural disaster event	A natural disaster event occurs if: Any major fire, storm, flood, earthquake or other natural disaster beyond the reasonable control of the DNSP occurs during the 2016–20 regulatory control period. The term ‘major’ in the above paragraph means an event that is serious and significant. It does not mean 'materially' as that term is defined in the Rules (that is 1 per cent of the distributor’s annual revenue requirement for that regulatory year).
Terrorism event	An act (including, but not limited to, the use of force or violence, the threat of force or violence, attacks or other disruptive activities against, or the deliberate introduction of harmful code or viruses to, computer systems, computer networks, data and/or communication systems, or the threat of such attacks or disruptive activities, or of the deliberate introduction of such harmful code or viruses) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear).

Proposed event	Proposed definition
Ending of the metering derogation event	An ending of the metering derogation event occurs if the impending or actual expiry of the Victorian Metering Derogation: (1) results in the distributor incurring costs to facilitate the introduction of metering contestability (whether prior to, or subsequent to the expiry of that Derogation) including, but not limited to: (a) system costs for establishing metering contestability; (b) meter provider of last resort costs; and (c) costs incurred to obtain non-metrology data from meters to enable the distributor to operate its network; and (2) does not constitute any category of pass through event specified in clause 6.6.1(a1)(1) to (4) of the Rules. For the purposes of this ending of the metering derogation event, the Victorian Metering Derogation is the derogation currently provided for in clause 9.9C of the Rules pursuant to the AEMC, National Electricity Amendment (Victorian Jurisdictional Derogation – Advanced Metering infrastructure) Rule 2013, 28 November 2013 and any subsequent derogation which may be made with similar effect to that in clause 9.9C of the Rules, albeit with a different expiry date.
Multiple trading relationships event	A multiple trading relationships event occurs if a change (including without limitation any NEM procedure or system change) occurs that: (1) results in the distributor incurring costs to facilitate two or more entities being able to provide services at a single connection point; and (2) does not constitute any category of pass through event specified in clause 6.6.1(a1)(1) to (4) of the Rules.
Retailer failure event	A retailer failure event occurs if a distributor incurs costs as a result of the failure of a retailer during a regulatory control period to pay a distributor an amount to which the distributor is entitled for the provision of direct control services, if: (a) an insolvency official has been appointed in respect of that retailer; and (b) the distributor is not entitled to payment of that amount in full under the terms of any credit support provided in respect of that retailer. For the purposes of this definition: (a) the term 'costs' includes amounts which the distributor was entitled to be paid (but which are or will be unpaid as a result of a retailer failure event) for the provision of direct control services, including, but not limited to: (i) charges for direct control services provided by the distributor; (ii) charges to recover the designated pricing proposal charges incurred by that distributor, and these amounts must be taken to be a cost that can be passed through and not a revenue impact of the event; (b) the term 'insolvency official' means a receiver, receiver and manager, administrator, provisional liquidator, liquidator, trustee in bankruptcy or person having a similar or analogous function; (c) the term 'credit support' takes its ordinary and natural meaning; and (d) other terms used in this definition that are defined in the Rules take their definition in the Rules.

Source: CitiPower

13.2.2 AER's preliminary determination

In its preliminary determination, the AER accepted the following proposed nominated pass through events, but amended the definitions of these events:

- insurance event (the AER also termed this event an 'insurance cap event');
- insurer credit risk event;

- natural disaster event;
- terrorism event; and
- retailer failure event.

The AER rejected the following proposed nominated pass through events:

- ending of the metering derogation event; and
- multiple trading relationships event.

13.2.3 Our response to the AER's preliminary determination

We accept the AER's preliminary determination that each of the following events is a nominated pass through event:

- insurance cap event;
- insurer credit risk event;
- natural disaster event;
- terrorism event; and
- retailer failure event.

However, for the reasons explained below, we do not wholly accept the AER's revisions to our proposed definitions of those events.

In addition, we accept the AER's preliminary determination not to approve the ending of the metering derogation event and the multiple trading relationship event as nominated pass through events for the 2016–2020 regulatory control period.

We observe that in its preliminary determination, the AER stated that an additional factor it took into account in assessing nominated pass through events was consistency in its approach to assessing nominated pass through events across its determinations.[1060] We query whether consistency in the AER's approach to assessing nominated pass through events across its determinations is properly considered to be a nominated pass through event consideration in accordance with paragraph (e) of those considerations. The AER has not notified network service providers generally that this is to be a nominated pass through event consideration, as is required by paragraph (e) if a matter the AER considers relevant is to constitute a nominated pass through event consideration. In any event, consistency in the AER's approach to assessing nominated pass through events should be a product of the AER's application of the NEO, revenue and pricing principles and the nominated pass through event considerations specified in paragraphs (a) to (d). It is not a matter that is, of itself, relevant to the assessment of whether the acceptance of a nominated pass through event would promote the relevant statutory objectives and thus permissibly notified to network service providers and considered by the AER pursuant to paragraph (e) of the nominated pass through event considerations.

Further, we consider that in seeking to ensure that the definitions of the insurance cap, insurer credit risk, natural disaster and terrorism pass through events in our distribution determination are consistent with the definitions the AER implemented in its previous distribution determinations for New South Wales, the Australian Capital Territory, Queensland and South Australia, the AER has failed to give meaningful consideration to the definitions we proposed for those events in our regulatory proposal. This is particularly the case with respect to

[1060] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-11.

our proposal to include a specific reference to cyber-terrorism type attacks in the definition of the terrorism event.

Insurance cap event

The AER accepted our nomination of an insurance cap event and, as noted above, we accept that decision. We also accept the AER's renaming of the event from 'insurance event' as we proposed, to 'insurance cap event'. However, for the reasons discussed below, we do not wholly accept the AER's proposed definition of this event.

AER's preliminary determination

The AER accepted that an insurance event is consistent with the nominated pass through considerations. In particular, it accepted that the event would protect us from high cost impact events which would be uneconomical to insure against.[1061]

However, the AER amended the title of the event to 'insurance cap event' and the proposed definition to:

- define the 'relevant policy limit' by reference to the greater of the level of insurance we have actually purchased and the policy limit assumed or provided for in determining approved forecast operating expenditure;
- include a modified list of matters to which the AER will have regard when assessing a pass through application in respect of an insurance event; and
- make clear that the event will only be triggered where costs incurred beyond the policy limit result in a material increase in the costs of providing direct control services.

The AER's proposed definition for an insurance cap event is as follows:

> *An insurance cap event occurs if:*
>
> *1. CitiPower makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy,*
>
> *2. CitiPower incurs costs beyond the relevant policy limit, and*
>
> *3. the costs beyond the relevant policy limit materially increase the costs to CitiPower in providing direct control services*
>
> *For this insurance cap event:*
>
> *4. the relevant policy limit is the greater of:*
>
> *(d) CitiPower's actual policy limit at the time of the event that gives, or would have given rise to a claim, and*
>
> *(e) the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the regulatory control period in which the insurance policy is issued.*
>
> *5. A relevant insurance policy is an insurance policy held during the 2016–20 regulatory control period or a previous regulatory control period in which CitiPower was regulated.*
>
> *Note for the avoidance of doubt, in assessing an insurance cap event cost pass through application under rule 6.6.1(j) the AER will have regard to:*

[1061] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-14.

i. the relevant insurance policy for the event, and

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event.

Our response to the AER's preliminary determination

We accept the AER's definition of the insurance cap event in its preliminary determination, except that we object to defining the 'relevant policy limit' by reference to the policy limit commensurate with the allowance for insurance premiums in our forecast operating expenditure allowance. The AER included this limb to address the concern that we may otherwise have an incentive to reduce expenditure on insurance (and therefore our operating expenditure relative to the approved forecast), by transferring the risk of insurable events to customers.[1062]

We consider that this limb of the AER's definition is very uncertain in meaning and effect. Given the manner in which the AER determines our operating expenditure allowance, it is not possible to ascertain a specific policy limit for particular insurance policies that is explicitly or implicitly commensurate with the allowance for insurance premiums included in forecast operating expenditure approved in the AER's distribution determination for the regulatory control period in which the policy is issued. Indeed, it is not possible to ascertain the allowance for insurance premiums. The AER's approach to determining our forecast operating expenditure did not involve any conclusion as to the efficient and prudent amount for insurance premiums.[1063] Further, it is impossible to determine the policy limit implicit in the operating expenditure allowance in the distribution determination for policies that were entered into after the distribution determination is made.

A decision by the AER to adopt a definition for a nominated pass through event, to which the Rules give legal force and effect, that lacks certainty of meaning and effect to this degree would constitute an incorrect exercise of discretion, and an unreasonable decision, in all the circumstances, as well as a decision that is not authorised by the Rules and involves an improper exercise of power.

Further, defining the 'relevant policy limit' by reference to that commensurate with the allowance for insurance premiums in our forecast operating expenditure allowance is unnecessary to address the AER's policy concern. This is because clause 6.6.1(j) of the Rules requires the AER, in making a positive change event determination, to take into account matters including the following:

(3) … the efficiency of the Distribution Network Service Provider's decisions and actions in relation to the risk of the positive change event, including whether the Distribution Network Service Provider has failed to take any action that could reasonably be taken to reduce the magnitude of the eligible pass through amount in respect of that positive change event and whether the Distribution Network Service Provider has taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of that positive change event;

…

(7) whether the costs of the pass through event have already been factored into the calculation of the Distribution Network Service Provider's annual revenue requirement for the regulatory control period in which the pass through event occurred or will be factored into the calculation of the Distribution Network Service Provider's annual revenue requirement for a subsequent regulatory control period.

In taking into account the efficiency of our actions and whether we failed to take any action that could reasonably be taken to reduce the magnitude of the event, the AER could consider the efficiency and prudency

1062 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-14.

1063 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, attachment 7.

of the policy limit of the relevant insurance policy. As such, the existence of the requirements in clause 6.6.1(j) of the Rules serves to deter us from inefficiently reducing our expenditure on insurance.

For this reason also, a decision by the AER to adopt a definition for the insurance cap event that defines the 'relevant policy limit' for the purposes of that definition by reference to 'the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance' would constitute an incorrect exercise of discretion, and an unreasonable decision, in all the circumstances, as well as a decision that is not authorised by the Rules and involves an improper exercise of power.

Accordingly, we propose the deletion of the definition of 'relevant policy limit' in paragraph 4 of the AER's definition and the incorporation of the first limb of that 'relevant policy limit' definition (i.e. paragraph 4a of the AER's definition) directly into the second paragraph of the definition of the insurance cap event, with the omission of the words 'or would have given rise to a claim'. We consider that the words 'or would have given rise to a claim' in item 4a of the AER's definition of the event are unclear and appear to be redundant. Since item 1 of the definition premises the existence of the event on the making of a claim and the receipt of a benefit from that claim, these additional words introduce unnecessary uncertainty into the definition of the event.

We therefore propose the following revised definition of the insurance cap event (with the revisions we propose to the AER's alternate definition shown in hard mark-ups).

An insurance cap event occurs if:

1. CitiPower makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy,

2. CitiPower incurs costs beyond the ~~relevant~~ actual policy limit of the relevant insurance policy at the time of the event that gives rise to the relevant claim, and

3. the costs beyond the relevant policy limit materially increase the costs to CitiPower in providing direct control services

For this insurance cap event~~:~~

~~4. the relevant policy limit is the greater of:~~,

~~(a) CitiPower's actual policy limit at the time of the event that gives, or would have given rise to a claim, and~~

~~(b) the policy limit that is explicitly or implicitly commensurate with the allowance for insurance premiums that is included in the forecast operating expenditure allowance approved in the AER's final decision for the regulatory control period in which the insurance policy is issued.~~

~~5. A~~a relevant insurance policy is an insurance policy held during the 2016-20 regulatory control period or a previous regulatory control period in which CitiPower was regulated.

Note for the avoidance of doubt, in assessing an insurance cap event cost pass through application under rule 6.6.1(j) the AER will have regard to:

i. the relevant insurance policy for the event, and

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event.

Insurer credit risk event

The AER accepted our nomination of an insurer credit risk event and, as noted above, we accept that decision. However, for the reasons discussed below, we do not wholly accept the AER's proposed definition of this event.

AER's preliminary determination

The AER accepted that an insurer credit risk event is consistent with the nominated pass through event considerations.[1064]

However, the AER amended the proposed definition to:

- remove the pass through of costs associated with changes to insurance premiums as a result of an insurer becoming insolvent;
- confine costs passed through to those arising in respect of our insurance policies with the insurer that becomes insolvent, rather than in respect of policies of insurance generally as a result of the insolvency of an insurer; and
- insert a list of matters to which the AER will have regard when assessing a pass through application in respect of an insurer credit risk event.

The AER's proposed definition for an insurer credit risk event is as follows:

> *An insurer's credit risk event occurs if:*
>
> *A nominated insurer of CitiPower becomes insolvent, and as a result, in respect of an existing or potential insurance claim for a risk that was insured by the insolvent insurer, CitiPower:*
>
> - *is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or*
> - *incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.*
>
> *Note: In assessing an insurer's credit risk event pass through application, the AER will have regard to, amongst other things,*
>
> - *CitiPower's attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation.*
> - *In the event that a claim would have been made after the insurance provider became insolvent, whether CitiPower had reasonable opportunity to insure the risk with a different provider.*

Our response to the AER's preliminary determination

The AER amended our proposed definition of the insurer credit risk event to confine the costs passed through to those arising in respect of our insurance policies with the insurer that becomes insolvent, rather than in respect of policies of insurance generally as a result of the insolvency of an insurer. In doing so, the AER introduced the term 'nominated insurer' of CitiPower. We consider that the meaning of 'nominated insurer' is unclear and as such introduces uncertainty into the definition of the insurer credit risk event. Accordingly, we propose that the word 'nominated' be deleted from the definition. We otherwise accept the AER's proposed definition.

1064 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-14.

We therefore propose the following revised definition of the insurer credit risk event (with the revisions we propose to the AER's alternate definition shown in hard mark-ups).

An insurer's credit risk event occurs if:

A ~~nominated~~ insurer of CitiPower becomes insolvent, and as a result, in respect of an existing or potential insurance claim for a risk that was insured by the insolvent insurer, CitiPower:

- *is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the insolvent insurer's policy; or*
- *incurs additional costs associated with funding an insurance claim, which would otherwise have been covered by the insolvent insurer.*

Note: In assessing an insurer's credit risk event pass through application, the AER will have regard to, amongst other things,

- *CitiPower's attempts to mitigate and prevent the event from occurring by reviewing and considering the insurer's track record, size, credit rating and reputation.*
- *In the event that a claim would have been made after the insurance provider became insolvent, whether CitiPower had reasonable opportunity to insure the risk with a different provider.*

Natural disaster event

The AER accepted our nomination of a natural disaster event and, as noted above, we accept that decision. However, for the reasons discussed below, we do not wholly accept the AER's proposed definition of this event.

AER's preliminary determination

The AER accepted that a natural disaster event is consistent with the nominated pass through event considerations. [1065] However, the AER amended the proposed definition to:

- remove the word 'storm' from our proposed definition;
- replace the reference to natural disasters 'beyond the reasonable control of the DNSP' with a reference to natural disasters 'not a consequence of the acts or omissions of the service provider';
- include a requirement that the event materially increases our costs of providing direct control services; and
- insert a list of matters to which the AER will have regard when assessing a pass through application in respect of a natural disaster event.

The AER's proposed definition of a natural disaster event is as follows:

A natural disaster event occurs if:

Any major fire, flood, earthquake or other natural disaster occurs during the 2016–20 regulatory control period and materially increases the costs to CitiPower in providing direct control services, provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider

The term 'major' in the above paragraph means an event that is serious and significant. It does not mean material as that term is defined in the Rules (that is 1 per cent of the DNSP's annual revenue requirement for that regulatory year).

[1065] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-17.

Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:

i. whether CitiPower has insurance against the event,

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and

iii. whether a relevant government authority has made a declaration that a natural disaster has occurred.

Our response to the AER's preliminary determination

We accept the AER's proposed definition of the natural disaster event, except that we oppose the AER's inclusion of the assessment factor of whether a relevant government authority has made a declaration that a natural disaster has occurred.[1066] The AER states generally that the assessment factors in respect of the natural disaster event have been included to provide greater transparency and certainty in the operation of nominated pass through events.[1067] However, we consider that the inclusion of this assessment factor only serves to create uncertainty.

We have no control over whether a government authority will, or will not, choose to make such a declaration. State and Territory Governments are responsible for declaring whether an event is a natural disaster. When a State Government declares a natural disaster, it is concerned with the impacts on the community and its citizens (e.g. damage to houses, injuries, etc.) and not on the impact to a network business. The Victorian Government has its own criteria for determining whether an event is a natural disaster or not, which may not necessarily mean that a natural disaster which impacts distributors would be declared. If the AER has this as a factor it considers in assessing whether to accept a pass through event, there is a risk that, contrary to the purpose of the pass through mechanism in the Rules, we may not be compensated for our efficient costs of an unforeseen and uncontrollable natural disaster, even where this has a catastrophic financial impact on the distributor.[1068]

Finally, we note the AER did not accept our proposed addition of 'major storm' to the definition of the natural disaster event.[1069] In doing so, the AER stated that it considers that a storm of sufficient magnitude to constitute a natural disaster is already captured by the words 'or other natural disaster'. On that basis, we do not oppose the AER's decision not to include 'major storm' in the definition of the natural disaster event.

We therefore propose the following revised definition of the 'natural disaster event' (with the revisions we propose to the AER's alternate definition shown in hard markups).

A natural disaster event occurs if:

Any major fire, flood, earthquake or other natural disaster occurs during the 2016–20 regulatory control period and materially increases the costs to CitiPower in providing direct control services, provided the fire, flood or other event was not a consequence of the acts or omissions of the service provider

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1066 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 15-18 to 15-19.

1067 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-18.

1068 The AEMC recognised in CP PUBLIC APP L. - AEMC, *Rule determination national electricity amendment (cost pass through arrangements for network service providers) Rule 2012*, 2 August 2012, pp. 18-19, that the specification of nominated pass through events is necessary to ensure that network service providers are provided with the opportunity to recover their efficient costs where those costs result from unforseen and uncontrollable events for which insurance is limited or not available on commercial terms and self-insurance is not appropriate. The AEMC recognised that in the absence of cost pass throughs in these circumstances, efficient investment in, and efficient operation of, a distributor's network would likely be adversely affected over the long term contrary to the NEO.

1069 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-18.

The term 'major' in the above paragraph means an event that is serious and significant. It does not mean material as that term is defined in the Rules (that is 1 per cent of the DNSP's annual revenue requirement for that regulatory year).

Note: In assessing a natural disaster event pass through application, the AER will have regard to, amongst other things:

i. whether CitiPower has insurance against the event, and

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event.~~, and~~

~~*iii. whether a relevant government authority has made a declaration that a natural disaster has occurred.*~~

Terrorism event

The AER accepted our nomination of a terrorism event and, as noted above, we accept that decision. However, for the reasons discussed below, we do not wholly accept the AER's proposed definition of this event.

AER's preliminary determination

The AER accepted that a terrorism event is consistent with the nominated pass through event considerations.[1070] However, the AER amended our proposed definition to:

- remove our specific reference to attacks against, and the deliberate introduction of harmful code or viruses to, computer systems, computer networks, data and/or communication systems and the threat of same;
- include a requirement that the event materially increases our costs of providing direct control services; and
- include factors the AER will have regard to when assessing a pass through application in respect of a terrorism event.

The AER's proposed definition of a terrorism event is as follows:

A terrorism event occurs if:

An act (including, but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to CitiPower in providing direct control services.

Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things:

i. whether CitiPower has insurance against the event,

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event, and

iii. whether a declaration has been made by a relevant government authority that a terrorism event has occurred.

[1070] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-19.

Our response to the AER's preliminary determination

We do not wholly accept the AER's definition of the terrorism event.

Firstly, we maintain our position in our regulatory proposal that the definition of 'terrorism event' should be amended to make specific reference to attacks against, and the deliberate introduction of harmful code or viruses to, computer systems, computer networks, data and/or communication systems and the threat of same.[1071]

The AER rejected our proposal in its preliminary determination because it considered that the risk of such attacks should be managed primarily through prudent and efficient steps to protect our IT systems.[1072] The AER considered that if there is too much reliance on ex-post measures, we would have disincentives to take prudent actions to manage the risks.

We have proposed forecast capital expenditure for the 2016–2020 period for IT security measures designed to ensure the security of our network is maintained, proactively monitored and managed.[1073] The AER did not allow our full forecast capital expenditure amount for those IT security projects in its preliminary determination.[1074] Further, to support those IT security measures, in our regulatory proposal we proposed an operating expenditure step change for monitoring our IT networks on a 24 hour basis. That step change was rejected by the AER in its preliminary determination.[1075] In our revised regulatory proposal we maintain that the step change should be allowed (see chapter 6). As explained in our regulatory proposal and our revised regulatory proposal (chapters 6 and 8), the risk of a cyber-attack is very real, and a recent report by the Australian Government's Cyber Security Centre on cybercrime indicates that the energy sector is the most likely target for cyber security threats.[1076]

Even if our forecast capital expenditure and operating expenditure in respect of IT security measures is allowed in full, we consider that allowing a pass through for costs related to a cyber-terrorism event would not result in us having a disincentive to take prudent actions to manage the risk. It is clear from our proposal to incur capital expenditure and operating expenditure during the 2016–2020 regulatory control period on increased IT security measures that we propose to take action to manage the risk of a cyber-terrorism act occurring. However, the pass through mechanism should still be available to enable us to recover our efficient costs of a cyber-terrorism event should such an event nonetheless occur.

The AER observes in its preliminary determination that on the basis of its terrorism event definition we could make a pass through application for events that are properly characterised as cyber-terrorism.[1077] Since the AER is of that view, making specific reference to cyber-terrorism activities in that definition would not lower our incentive to take prudent actions to manage the risk. Further, we submit that, notwithstanding the AER's view, to provide us with certainty that the terrorism event would cover acts of cyber-terrorism, it is necessary for the definition of that event to be amended as proposed below and in our regulatory proposal.

[1071] CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix L, p. 16.

[1072] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-19.

[1073] CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix E, pp. 152–155.

[1074] AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 6-103.

[1075] AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-82.

[1076] CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix E, pp. 152–155 and appendix G, pp. 10–11; Australian Cyber Security Centre, *2015 Threat Report*, July 2015, figure 1, p. 10.

[1077] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-19.

If the definition is so amended, we would still have an incentive to act prudently and efficiently to manage the risk of a cyber-terrorism act occurring. This is because clause 6.6.1(j)(3) of the Rules provides that in making a determination under clause 6.6.1(d) of the Rules of the approved pass through amount and the amount that should be passed through to distribution network users in each regulatory year, the AER must take into account the efficiency of our decisions and actions in relation to the risk of the positive change event, including whether we have failed to take any action that could reasonably be taken to reduce the magnitude of the eligible pass through amount in respect of that positive change event, and whether we have taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of that positive change event. We observe, however, that while we will seek to act prudently and efficiently to manage such a risk, we may not be best placed to manage the full extent of the risk of a cyber-terrorism attack.

Secondly, one of the assessment factors the AER included within the definition of 'terrorism event' is whether a relevant government authority has made a declaration that a terrorism event has occurred.[1078] We oppose the AER's proposed inclusion of this assessment factor. Rather than providing clarity, the meaning of this assessment factor is uncertain. For example, it is unclear what 'relevant government' means. In addition, government authorities would have their own criteria as to when they should make such a declaration and we have no control over whether a government authority will, or will not, choose to make such a declaration.

Further, we consider that there are likely to be political sensitivities around the making of such a declaration. A decision whether to make such a declaration is likely to be highly political and the motives for making (or not making) such a declaration may not necessarily relate to the impact of the terrorism event on distributors. As a consequence, a government authority may not necessarily make such a declaration even in circumstances where an act of terrorism has occurred. For example, according to news reports there was a recent cyber attack on the Bureau of Meteorology's IT systems in response to which a classified report recommended the complete replacement of the Bureau's computer systems.[1079] The Bureau of Meteorology is a critical national resource and also provides a gateway to other government agencies. As far as we are aware, the Government did not make a declaration regarding that event. In this regard, we observe that an ABC News article in respect of that event states that '[t]here is now active debate within Government about whether it should stick with its policy of simply refusing to engage when evidence emerges of a cyber attack'.[1080]

If the AER has this as a factor it considers in assessing whether to accept a pass through event, there is a risk that, contrary to the purpose of the pass through mechanism in the Rules, we may not be compensated for our efficient costs of an unforeseen and uncontrollable terrorism event, even where that event has a catastrophic financial effect on the distributor.[1081]

We therefore propose the following revised definition of the terrorism event (with the revisions we propose to the AER's alternate definition shown in hard mark-ups).

A terrorism event occurs if:

[1078] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-20.

[1079] ABC News report (online), C*hina blamed for massive cyber attack on Bureau of Meteorology computer*, 2 December 2015; ABC News report (online), *Classified report on Bureau of Meteorology cyber attack recommends computer system overhaul*, 3 December 2015.

[1080] ABC News report (online), *Classified report on Bureau of Meteorology cyber attack recommends computer system overhaul*, 3 December 2015.

[1081] The AEMC recognised in CP PUBLIC APP L.1 - AEMC, *Rule determination national electricity amendment (cost pass through arrangements for network service providers) Rule 2012*, 2 August 2012, pp. 18-19, that the specification of nominated pass through events is necessary to ensure that network service providers are provided with the opportunity to recover their efficient costs where those costs result from unforseen and uncontrollable events for which insurance is limited or not available on commercial terms and self-insurance is not appropriate. The AEMC recognised that in the absence of cost pass throughs in these circumstances, efficient investment in, and efficient operation of, a distributor's network would likely be adversely affected over the long term contrary to the NEO.

An act (including, but not limited to, the use of force or violence or the threat of force or violence, attacks or other disruptive activities against, or the deliberate introduction of harmful code or viruses to, computer systems, computer networks, data and/or communication systems, or the threat of such attacks or disruptive activities, or of the deliberate introduction of such harmful code or viruses) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear) and which materially increases the costs to CitiPower in providing direct control services.

Note: In assessing a terrorism event pass through application, the AER will have regard to, amongst other things:

i. whether CitiPower has insurance against the event, and

ii. the level of insurance that an efficient and prudent NSP would obtain in respect of the event.~~, and~~

~~iii. whether a declaration has been made by a relevant government authority that a terrorism event has occurred.~~

Retailer failure event/retailer insolvency event

The AER accepted our nomination of a retailer failure event and, as noted above, we accept that decision. However, for the reasons discussed below, we do not wholly accept the AER's proposed definition of that event. Further, for consistency with the retailer insolvency event in the Rules, we propose that the event should be referred to as a 'retailer insolvency event'.

AER's preliminary determination

The AER approved a nominated retailer failure event as a pass through event in its preliminary determination on the basis that the National Energy Customer Framework (**NECF**) has not been adopted in Victoria, and accordingly, the prescribed retailer insolvency event under the Rules does not apply to Victorian distributors.[1082]

The AER rejected our proposed definition of 'retailer failure event', which drew on a rule change proposal currently under consideration by the AEMC, as the outcomes of that process were currently unknown and it did not want to approve a pass through event which was inconsistent with the retailer insolvency event that applied in other jurisdictions through the Rules. However, the AER considered it best to apply the Rules event 'as in force from time to time', to ensure that the protection afforded to Victorian distributors remains consistent with that available to distributors in NECF jurisdictions.

The AER's proposed definition of a retailer failure event is as follows:

Prior to the commencement of the National Energy Customer Framework in Victoria, retailer insolvency event has the meaning set out in the NER as in force from time to time.

Note: This retailer insolvency event will cease to apply as a nominated pass through event on commencement of the National Energy Customer Framework in Victoria.

Our response to the AER's preliminary determination

We do not wholly accept the AER's definition of the retailer failure event and propose that the definition be amended as described below.

[1082] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-21.

The AER defines the retailer failure event by reference to the retailer insolvency event set out in the Rules.

The current definition of retailer insolvency event in chapter 10 of the Rules is:

> *The failure of a retailer during a regulatory control period, to pay a Distribution Network Service Provider an amount to which the service provider is entitled for the provision of direct control services, if:*
>
> *(a) an insolvency official has been appointed in respect of that retailer; and*
>
> *(b) the Distribution Network Service Provider is not entitled to payment of that amount in full under the terms of any credit support provided in respect of that retailer.*

Firstly, we observe that the meaning of 'retailer' in the definition of retailer insolvency event in chapter 10 of the Rules is defined by reference to the National Energy Retail Law which is not in effect in Victoria. 'Retailer' is defined in chapter 10 of the Rules to have the same meaning as in the Law. Under section 2 of the Law, 'retailer' is defined as 'a person who is the holder of a retailer authorisation issued under the National Energy Retail Law in respect of the sale of electricity'. We note that this circumstance may also occur in future changes made to the retailer insolvency event in the Rules. That is, future changes to the retailer insolvency event in the Rules may introduce words that are defined by reference to provisions of the Rules or the National Energy Retail Law which are not in operation in Victoria.

Accordingly, we propose that the AER's definition of retailer failure event be amended to provide that:

- where used in the definition of 'retailer insolvency event' in the Rules, the term 'retailer' means the holder of a licence to sell electricity under the *Electricity Industry Act 2000* (Vic) or an exemption from the requirement to hold a licence to sell electricity under that Act; and
- other terms used in the definition of retailer insolvency event in the Rules as a consequence of amendments made to that definition from time to time, which would otherwise take their meaning by reference to provisions of the Rules or National Energy Retail Law that not in force in Victoria, take their ordinary meaning and natural meaning, or their technical meaning (as the case may be).

Secondly, while consistent with our regulatory proposal, the AER refers to the event as a 'retailer failure event' in its distribution determination, in the definition of the event the AER refers to the event as a retailer insolvency event.[1083] Accordingly, for consistency with the retailer insolvency event in the Rules, the AER should amend its distribution determination to refer to the nominated pass through event as a 'retailer insolvency event'.

Thirdly, we propose an amendment to the AER's definition to reflect the language that would be used in the legislation to apply the National Energy Retail Law. That is, we propose replacing the words '[p]rior to the commencement of the National Energy Customer Framework in Victoria' in the AER's definition with '[u]ntil such time as the National Energy Retail Law set out in the Schedule to the National Energy Retail Law (South Australia) Act 2011 of South Australia is applied as a law of Victoria'.

Finally, as discussed in our regulatory proposal, the Council of Australian Government' (**CoAG**) Energy Council has proposed a rule change request that seeks to ensure that distributors are able to pass through foregone revenue, in the form of distribution network charges, for the provision of direct control services following the insolvency of a retailer (**CoAG Energy Council Rule Change Request**).[1084] The CoAG Energy Council Rule Change Request also proposes an amendment with the effect that the retailer insolvency event will not be subject to the materiality threshold that is applied to other pass through events. The CoAG Energy Council is proposing these amendments

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[1083] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, Overview, p. 59.

[1084] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, appendix L, p. 28; CP PUBLIC APP L.24 - SCER, *Definition of retailer insolvency costs rule change request*, March 2014.

in order to correct omissions made in the drafting of amendments to the Rules which were given effect to by the National Electricity (National Energy Retail Law) Amendment Rule 2012 and the National Electricity (National Energy Retail Law) Amendment Rule 2012 and to reflect its original policy intent with respect to the retailer insolvency pass though event in the Rules.[1085]

Accordingly, the CoAG Energy Council has proposed the following amendments to the Rules:[1086]

- the insertion of a new and separate limb within the current definition of a 'positive change event' in chapter 10 of the Rules to include the occurrence of a retailer insolvency event. This would allow for the costs arising from a retailer insolvency event to be passed through, without being subject to the materiality threshold that is applied to other cost pass through events;
- the insertion of a new definition of retailer insolvency costs in chapter 10 of the Rules, which would specifically include revenue foregone to distributors as a result of a retailer insolvency event. This would enable distributors to seek to recover unpaid revenue through the pass through mechanism in the Rules, and not just the relevant additional costs, following the occurrence of a retailer insolvency event; and
- secondary amendments for the purposes of drafting consistency to italicise the term 'retailer insolvency costs' where it appears elsewhere in the Rules.

In the preliminary determination, the AER stated its intention to ensure that the protection afforded to Victorian distributors remains consistent with that available to distributors in NECF jurisdictions and to provide for changes to the retailer insolvency event prescribed in the Rules during the regulatory control period to also apply to Victorian distributors.[1087] Accordingly, we propose the AER's definition of this event be amended to provide that the terms 'eligible pass through amount' and 'positive change event' where they appear in the Rules are modified in respect of this nominated retailer insolvency event in the same manner as those terms are modified in respect of the retailer insolvency event prescribed in the Rules from time to time.

We therefore propose the following revised definition of retailer insolvency event.

> *Until such time as the National Energy Retail Law set out in the Schedule to the National Energy Retail Law (South Australia) Act 2011 of South Australia is applied as a law of Victoria, retailer insolvency event has the meaning set out in the National Electricity Rules as in force from time to time, except that:*
>
> *(a) where used in the definition of 'retailer insolvency event' in the National Electricity Rules, the term 'retailer' means the holder of a licence to sell electricity under the Electricity Industry Act 2000 (Vic) or an exemption from the requirement to hold a licence to sell electricity under that Act; and*
>
> *(b) other terms used in the definition of retailer insolvency event in the Rules as a consequence of amendments made to that definition from time to time, which would otherwise take their meaning by reference to provisions of the National Electricity Rules or National Energy Retail Law not in force in Victoria, take their ordinary meaning and natural meaning, or their technical meaning (as the case may be).*
>
> *For the purposes of this definition, the terms 'eligible pass through amount' and 'positive change event' where they appear in the National Electricity Rules are modified in respect of this retailer insolvency event in the same manner as those terms are modified in respect of the retailer insolvency event prescribed in the National Electricity Rules from time to time.*

[1085] CP PUBLIC APP L.24 – SCER, *Definition of retailer insolvency costs rule change request*, March 2014; CP PUBLIC APP 14.1 - AEMC, *Consultation paper, National Electricity Amendment (Retailer insolvency events – cost pass through provisions) Rule 2015*, 30 October 2014, p. 34.

[1086] CP PUBLIC APP 14.1 – AEMC, *Consultation paper, National Electricity Amendment (Retailer insolvency events – cost pass through provisions) Rule 2015*, 30 October 2014, p. 3.

[1087] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-21.

Note: This retailer insolvency event will cease to apply as a nominated pass through event on commencement of the National Energy Customer Framework in Victoria.

13.2.4 Our revised regulatory proposal

In this revised regulatory proposal, we:

- maintain our position in our regulatory proposal that the following events should be nominated pass through events in our distribution determination:
  - insurance cap event (note, consistent with the AER's preliminary determination, in our revised regulatory proposal we propose this event be called an 'insurance cap event' rather than an 'insurance event');
  - insurer credit risk event;
  - natural disaster event;
  - terrorism event; and
  - retailer insolvency event (note, consistent with the pass through event prescribed by the Rules, we propose that this event be called a 'retailer insolvency event', rather than a 'retailer failure event');
- propose that the definitions of the insurance cap event, insurer credit risk event, natural disaster event and terrorism event be those set out in the AER's preliminary determination, subject to the amendments as described above. In summary:
  - for the insurance cap event, we propose that the definition of the event be the definition set out in the AER's preliminary determination, however, with the definition of 'relevant policy limit' in the fourth paragraph of the AER's definition deleted and the words 'actual policy limit of the relevant insurance policy at the time of the event that gives rise to the relevant claim' included in the second paragraph of the definition of the insurance cap event;
  - for the insurance credit risk event, we propose that the definition of the event be the definition set out in the AER's preliminary determination, however, with the word 'nominated' deleted;
  - for the natural disaster event, we propose that the definition of the event be the definition set out in the AER's preliminary determination, however, with the assessment factor in paragraph (iii) of the note deleted, being 'whether a relevant government authority has made a declaration that a natural disaster has occurred';
  - for the terrorism event, we propose that the definition of the event be the definition set out in the AER's preliminary determination, with the following amendments:
    - include a specific reference to attacks against, and the deliberate introduction of harmful code or viruses to, computer systems, computer networks, data and/or communication systems and the threat of same (consistent with our position in our regulatory proposal); and
    - delete the assessment factor in paragraph (iii) of the note being 'whether a relevant government authority has made a declaration that a terrorism event has occurred';
- propose a new definition of the retailer insolvency event having regard to the definition set out in the AER's preliminary determination. In particular, we propose the following amendments to the AER's event:
  - the name of the 'retailer failure event' be amended to a 'retailer insolvency event'; and
  - the definition of retailer insolvency event be amended to:

- provide for the circumstance where terms used in the retailer insolvency event in the Rules are defined by reference to provisions of the Rules or the National Energy Retail Law which are not in effect in Victoria; and
- provide that the terms 'eligible pass through amount' and 'positive change event' where they appear in the Rules are modified in respect of this nominated retailer insolvency event in the same manner as those terms are modified in respect of the retailer insolvency event prescribed in the Rules from time to time; and

- remove nominated pass through events for the ending of metering derogation event and multiple trading relationships event.

The definitions of our nominated pass through events proposed for the purpose of this revised regulatory proposal are set out in the preceding section of this chapter which describes our response to the AER's preliminary determination.

13.3 Application to alternative control services

13.3.1 Rule requirements

The Rules allow for the cost pass through arrangements in clause 6.6.1 to apply to alternate control services. While clause 6.6.1 is contained in Part C of Chapter 6 of the Rules which relates to building block determinations for standard control services, clause 6.2.6(c) of the Rules provides that the control mechanism for alternative control services may utilise elements of Part C of Chapter 6 (with or without modification). Below that clause in the Rules, an example is given that the 'distribution determination might provide for the application of clause 6.6.1 to pass through events with necessary adaptions and specified modifications'. [1088]

Pass through events specified in clauses 6.6.1(a1)(1) to (4) of the Rules and nominated pass through events can relate to both standard control services and alternative control services. The definitions of the pass through events specified in clauses 6.6.1(a1)(1) to (4) of the Rules allow the pass through provisions to apply to both standard control and alternative control services as they use the term 'direct control services', which encompasses both standard control services and alternative control services.[1089]

In respect of nominated pass through events, clause 6.6.1(a1)(5) of the Rules provides that a pass through event includes any other event specified in a distribution determination as a pass through event for the determination. Clause 6.5.10 of the Rules provides that a building block proposal may include a proposal as to the events that should be defined as pass through events under clause 6.6.1(a1)(5), having regard to the nominated pass through event considerations. While clause 6.5.10 refers to 'building block proposal', which is defined as the part of the distributor’s regulatory proposal relevant to standard control services, as noted above clause 6.2.6(c) enables the control mechanism for alternative control services to utilise elements of Part C (with or without modification).

[1088] Consistently with that example, the AER notes at p. 79 of CP PUBLIC ATT 2.1 — AER, *Final framework and approach for the Victorian electricity distributors regulatory control period commencing 1 January 2016*, 24 October 2014 that the control mechanism for alternative control services in a distribution determination may incorporate a pass through mechanism.

[1089] See the definitions of regulatory change event, service standard event, tax change event and retailer insolvency event set out at the beginning of this attachment and contained in chapter 10 of the Rules. The definition of 'alternative control service' in chapter 10 of the Rules provides that an alternative control service is a 'direct control service' but not a 'standard control service'. The definition of 'standard control service' provides that a standard control service is a 'direct control service' that is subject to a control mechanism based on a distributor's total revenue requirement. Further, clause 6.2.2(a) of the Rules provides that direct control services are to be divided into two subclasses being (1) standard control services and (2) alternative control services.

The AER is required to make a constituent decision on the form of the control mechanisms for alternative control services and the formulae that give effect to those control mechanisms.[1090] In respect of our distribution determination, that decision may include a decision on the formulae to enable cost pass throughs for alternative control services.

13.3.2 Initial regulatory proposal

In chapter 14 and appendix L of our regulatory proposal, we proposed that the pass through mechanism in the Rules for specified and nominated pass through events be applied to alternative control services through the formulae for the control mechanisms for alternative control services, however, that in so applying the pass through mechanism to alternative control services a modification be made to the application of the materiality threshold for cost pass throughs in respect of alternative control services. We proposed that the definition of 'materially' to apply in respect of alternative control services for the purposes of the definitions of 'positive change event' and 'negative change event' in chapter 10 of the Rules, the pass through events specified in clauses 6.6.1(a1)(1) to (4) of the Rules and nominated pass through events be modified to the ordinary and natural meaning of the term 'materially'.[1091]

13.3.3 AER's preliminary determination

The AER approved the application of nominated pass through events to alternative control services.[1092] The AER observed that this is consistent with the definitions of the prescribed pass through events specified in clause 6.6.1(a1)(1) to (4) of the Rules which refer to direct control services (which encompass both standard control services and alternative control services).

However, the AER rejected our proposals to:

- vary the control mechanisms for alternative control services so that approved pass through amounts would be recoverable from customers of alternative control services, as the AER determined that such pass through amounts would be recovered via standard control service charges; and
- modify the definition of 'materially' applicable to pass throughs in respect of alternative control services to the ordinary and natural meaning of the term 'materially'.

13.3.4 Our response to the AER's preliminary determination

We agree with the AER's decision to approve the application of nominated pass through events to alternative control services.

We understand the AER's position to be that the Rules in and of itself applies the pass through mechanism in clause 6.6.1 of the Rules (including all defined pass through events, being events prescribed by the Rules and those specified in the distribution determination) to alternative control services.[1093] However, for the avoidance of doubt, we request that the AER specify this in its final determination in connection with its constituent decision on the form of the control mechanism for alternative control services under clause 6.12.1(12) of the Rules. Alternatively, if the AER considers this unnecessary, we request the AER to expressly confirm that this is because it shares our understanding that the correct legal construction of the Rules is that the Rules in and of itself applies clause 6.6.1 to alternative control services.

1090 NER, cl. 6.12.1(12).

1091 CitiPower, *Regulatory Proposal 2016–2020*, April 2015, appendix L, p. 35.

1092 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 15-12 to 15-13.

1093 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 15-12.

We accept the AER's decision to reject our proposal to modify the definition of 'materially' applicable to pass throughs in respect of alternative control services.

Further, we accept the AER's decision that approved pass through amounts related to alternative control services will be recovered via standard control services charges. We observe that in its preliminary determination the AER made provision for approved cost pass through amounts in the B factor in the revenue cap formulae for standard control services.[1094] To make clear that such pass through amounts may include approved pass throughs for both alternative control services and standard control services, we request the AER to amend the description of the B^t term in the revenue cap formula for standard control services to make specific reference to 'direct control services' in describing the AER approved pass through amounts in that term. That is, we request that the words 'the AER approved pass through amounts (positive or negative) with respect to regulatory year t' in the last bullet point of the description of the B^t term be amended to state 'the AER approved pass through amounts in respect of direct control services (positive or negative) with respect to regulatory year t'. A corresponding amendment should be made to the B^t term in the side constraint formula.[1095]

13.3.5 Our revised regulatory proposal

We have revised our regulatory proposal such that we no longer propose to vary the control mechanism for alternative control services so that approved pass through amounts would be recoverable from customers of alternative control services, or to modify the application of the materiality threshold with respect to cost pass throughs in respect of alternative control services.

We request the AER to specify in its final determination in connection with its constituent decision on the form of the control mechanism for alternative control services under clause 6.12.1(12) of the Rules that the pass through mechanism in clause 6.6.1 of the Rules (including all defined pass through events, being events prescribed by the Rules and those specified in the distribution determination) applies to alternative control services. Alternatively, if the AER considers this unnecessary, the AER should expressly confirm that this is because it shares our understanding that the correct legal construction of the Rules is that the Rules in and of itself applies clause 6.6.1 to alternative control services.

Further, we request the AER to amend the description of the B^t term in the revenue cap formula for standard control services to make specific reference to 'direct control services' in describing the AER approved pass through amounts in that term.

1094 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, pp. 14-10 and 14-13.

1095 AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 14-16.

Metering 14

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14 Metering

We have prepared our expenditure forecasts based on the same practices and procedures we applied during the Advanced Metering Infrastructure (**AMI**) roll out. This ensures that our forecast expenditure reflects our efficient and prudent costs of operating the metering service over the 2016–2020 regulatory control period.

We ran the most successful AMI roll out program. We ensured that the roll out of AMI meters was completed on time and on budget. We set up efficient and prudent contracting arrangements to minimise the risk of cost overruns or project delays. CitiPower and Powercor were the only Victorian distributors to run the AMI program on time and on budget without incurring significant expenditure excesses. As a result, we had the lowest metering charges in 2015, across all meter types.

Even though we have demonstrated efficient and prudent metering expenditure both in actuals and forecasts, the Australian Energy Regulator's (**AER's**) preliminary determination does not allow us to recover our forecast efficient and prudent costs of providing metering services. The AER has determined unreasonably low expenditure allowances, particularly in relation to its decisions to reject our meter purchase and meter replacement costs and real price escalation.

Importantly, we have updated our forecast expenditure requirements to reflect the Australian Energy Market Commission's (**AEMC**) final decision to extend the Victorian derogation to 1 December 2017.

Meter purchase costs

It is unreasonable for the AER to substitute our unit rates for AusNet Services and Jemena because:

- our proposed unit rates are based on quotes from our two meter providers and we undertook a rigorous tendering process to identify our preferred meter providers;
- AusNet Services unit rates do not include the value of the Network Interface Card (**NIC**). We require the NIC for the meter to be compatible with our mesh radio communications network. We purchase the NIC and meter as a bundle; and
- meter suppliers offer volume discounts on unit rates and AusNet Services and Jemena have proposed higher meter volumes than us because they assume meter contestability is not introduced until post 2020.

Meter replacement costs

The AER has erred in its view that meter replacement time is less than new connections. Meter replacement incurs longer labour time because, among other things, we:

- respond reactively to meter faults and therefore cannot coordinate works to minimise travel time; and
- action our fault response process including following necessary safety procedures and processes to identify the cause of the fault.

While the AER states that it has applied our field worker labour rate, its modelling indicates that it has only applied the business-hours labour rate and excluded on-costs. The AER's substitution of our labour rates for meter replacements is unreasonable because:

- meter faults occur both during business-hours and after-hours; and
- we must recover the overheads associated with labour through the on-costs.

Real price growth

The AER's determination to provide zero real price growth is unreasonable because:

- there is clear evidence that real labour prices will increase over the 2016–2020 regulatory control period; and

- the AER has no basis for assuming the real labour price increases can be offset by pre-emptive and unsubstantiated productivity improvements.

14.1 Rule requirements

The Advanced Metering Infrastructure Order in Council (**AMI OIC**) is an Order made under sections 15A and 46D of the *Electricity Industry Act 2000* (VIC). Clause 5K of the AMI OIC specifies that for the 2016–2020 regulatory control period, the following provisions apply:

> *(a) Subject to clause 5L, for the purposes of the second Subsequent Price Determination:*
>
> (i) an asset base (be it for standard control services or alternative control services) for the second Subsequent Price Determination must have added to it the metering asset base of Regulated Services as at the End Date (as that metering asset base has been determined in accordance with this Order); and
>
> (ii) there shall be no optimisation of the metering asset base of Regulated Services at the time that it is, pursuant to clause 5K(a), added to an asset base for the second Subsequent Price Determination.
>
> *(b) Subject to this Order, after the End Date Regulated Services are regulated pursuant to the National Electricity (Victoria) Law, the National Electricity Rules and the Subsequent Price Determination. Provided that:*
>
> (i) exit fees and restoration fees (and the services to which those exit fees and restoration fees applied) continue to be regulated after the End Date on the same basis as they are regulated under this Order;
>
> …..
>
> (iv) for the purposes of a distribution determination with respect to the "type 5, 6 and smart metering – regulated service", the AER may have regard to:
>
> (A) the actual and expected operating expenditure during the initial regulatory period of a distributor of, or in relation to, the provision, installation, maintenance and operation of advanced metering infrastructure and associated services and systems;
>
> (B) the actual and expected capital expenditure during the initial regulatory period of a distributor of, or in relation to, the provision, installation, maintenance and operation of advanced metering infrastructure and associated services and systems; and
>
> (C) this Order and any determination made pursuant to this Order.

14.2 Capital expenditure

14.2.1 Meters

Initial regulatory proposal

<u>Meter volumes</u>

We forecast the volume of meters required during the 2016–2020 regulatory control period as follows:

- new metering connections for the 2016 regulatory year only based on forecasts of new residential connections for standard control services developed by the Centre for International Economics (**CIE**). To estimate the volume of new connections by meter type, we applied the proportion of new meters installed by meter type in 2014;
- reactive meter replacements for 2016–2020 based on the 2014 fault rates. Reactive replacements are when the meter becomes faulty unexpectedly, for example, due to a fault in the meter itself, a fault in the

communications equipment contained within the meter, or a High Voltage Injection which caused the meter to become faulty;

- proactive meter replacements for the 2016 regulatory year only based on number of type 5 and 6 meters remaining in our network area as at December 2014 and an estimate of how many replacements can be undertaken during 2015 and 2016. Proactive replacements are where we initiate a program to upgrade or replace meters, including upgrading remaining type 5 and 6 meters to smart meters and replacing meters identified as faulty through sample testing; and
- customer initiated upgrades for the 2016 regulatory year only based on the actual volume of upgrades in 2014.

Meter purchase

We forecast the per unit cost of purchasing new meters, by meter type, based on quotes, in United States of America dollars (**USD**), from our two main meter providers, Landis + Gyr Pty Ltd (**L+G**) and Secure Australasia Pty Ltd.[1096] We converted the quoted unit prices to Australian dollars (**AUD**) based on a forecast exchange rate between AUD and USD derived from Bloomberg.

Meter installation costs

We forecast our labour costs for installing meters as follows:

- installation costs for new connections and customer initiated upgrades to be charged directly to the customer as an alternative control service, refer to chapter 15;
- installation costs for meter replacements are forecast based on:
  - our actual average number of labour hours incurred installing a replacement meter by meter type; and
  - our 2015 labour rates escalated for real price growth.

AER's preliminary determination

Meter volumes

The AER's preliminary determination accepted our proposed meter volumes. The AER noted that it would reconsider meter volumes in light of further information regarding the introduction of meter contestability in Victoria.

Meter purchase

The AER's preliminary determination rejected our unit rate for meter purchase. For each meter type, the AER substituted our proposed per unit meter purchase cost with the lowest per unit cost proposed by the Victorian distributors.

Meter installation costs

The AER's preliminary determination rejected our proposed meter installation costs for meter replacements.

The AER's preliminary determination was based on the assumption that the time to install a replacement meter should be no more than the installation costs for a new meter connection because a new connection involves other activities. The AER's modelling indicates it has only applied our alternative control services charge for the field time associated with a new connection. This excludes labour time associated with back-office support for a

[1096] Secure, *Proposal for supply of Smart Meters BAU to PNS*, August 2014. Landis & Gyr, *Request for quotation*, November 2014.

new connection. The AER provided no reason for this. The AER also considered that the time taken to replace a meter should not vary by meter type. The AER also provided no reasons for this conclusion.

The AER preliminary determination states that it applied our proposed field worker labour rate.[1097] However in its modelling the AER has only applied our business-hours labour rate and excluded on-costs. The AER's preliminary determination therefore rejected our labour rates without providing any basis or justification.

The AER therefore substituted our proposed meter installation costs with:

- the field time to undertake a new connection based on the field component of our proposed alternative control services charge; multiplied by
- our proposed field worker labour rate for new connections during business-hours only and exclusive of on-costs.

Our response to the AER's preliminary determination

<u>We ran an efficient and prudent AMI roll out program</u>

We ran a very successful AMI roll out program. We ensured that our roll out program was completed on time and on budget. We set up efficient and prudent contracting arrangements to minimise the risk of cost overruns or project delays. We outsourced many of the AMI roll out activities to external parties and our contractual arrangements were structured to provide sufficient flexibility to ensure we were able to achieve the AMI roll out at efficient cost.

We took a prudent approach to managing any contingencies that may have arisen during the program. We took a 'walk before you run' approach, which provided opportunity to identify best practice before ramping up the scale of operations. Our AMI deployment profile is characterised by slow initial ramp-up followed by a rapid ramp-up and then a stabilised installation rate until conclusion of the program. We focussed on non-complex sites (single phase meters) first before tackling more complex sites (i.e. three phase meters and sites where there was sparse customer density).

Importantly, CitiPower and Powercor were the only Victorian distributors to run the AMI program on time and on budget and without incurring significant expenditure excesses. As a result, we had the lowest metering charges in 2015, across all meter types.

We consider our past performance to be relevant to the AER's assessment of our proposed expenditure. Clause 5K(b)(iv) of the AMI OIC states that the AER may have regard to our actual and expected operating and capital expenditure incurred during the AMI roll out. We have prepared our expenditure forecasts based on the same practices and procedures we applied during the AMI roll out. This ensures that our forecast expenditure reflects our efficient and prudent costs of operating the regulated metering service over the 2016–2020 regulatory control period.

However, the AER has not taken into account our strong performance in managing the AMI roll out. Conversely the AER has rejected our proposed expenditure for meter purchase costs and meter installation costs, despite these being the two major categories of expenditure where the other Victorian distributors incurred expenditure excesses.[1098] We find this outcome unreasonable.

[1097] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 16-40.

[1098] Energia, *Review of Victorian Distribution Network Service Provider's Advanced Metering Infrastructure 2015 Charges Revision Applications*, December 2014, p. 8.

Meter volumes

We do not accept the AER's preliminary determination on meter volumes. This is because our proposed meter volumes assumed that metering contestability would be introduced in Victoria on 1 January 2017. On 26 November 2015, the AEMC published its final determination on changes to the National Electricity Rules (**Rules**) for the introduction of metering contestability.[1099] The final Rule change results in the introduction of metering contestability in Victoria on 1 December 2017. We therefore propose updating our meter volumes for new meter connections, proactive meter replacements and customer initiated upgrades to include forecast volumes up until 1 December 2017.

Meter purchase

We dispute the AER's preliminary determination to substitute our meter unit rates for the lowest unit rate proposed by the Victorian distributors.

The AER has not provided any transparency regarding the basis of the lowest unit rate proposed for each meter type. Our review of the AER's preliminary determinations for the other Victorian distributors indicates the AER has applied AusNet Services proposed unit rate for four meter types and Jemena's proposed meter unit rate for two meter types.

It is not appropriate for the AER to substitute our meter hardware unit rates for AusNet Services proposed unit rates. AusNet Services meters do not contain a NIC and are therefore not compatible with our mesh radio communications network.

As shown in the table below, our unit meter purchase costs would be comparable with the AER's substituted unit rates if the value of the NIC is excluded from our unit rates. Importantly, the AER must apply our unit rates inclusive of the NIC as the meter hardware and NIC card are an integrated product and the meter providers pre-load the NIC card into the meters. The NIC is required for compatibility with our mesh radio communications network. Failure to provide a meter hardware unit rate inclusive of the NIC would result in a capital expenditure allowance less than the efficient and prudent costs required to operate our metering services and therefore would be inconsistent with the Rules.

[1099] AEMC, Rule determination, *National Electricity Amendment (Expanding competition in metering and related services) Rule 2015, National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015*, November 2015.

Table 14.1 Comparison of meter hardware unit costs ($, 2015)

	Revised proposal	Revised proposal	AER Preliminary Decision
	Excl. NIC	Incl. NIC	
AMI 1Ph 1e	133.73	229.00	166.62
AMI 1Ph 1e + contactor	160.41	255.68	198.41
AMI 1Ph 2e + contactor	186.14	281.41	217.73
AMI 3 Ph	251.08	417.05	288.34
AMI 3 Ph + contactor	280.92	446.90	296.44
AMI 3 Ph CT	367.16	533.14	379.11

Source: CitiPower, AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, Metering capex model.

We also oppose the use of unit rate benchmarking when there is insufficient transparency regarding the basis of the data which is being benchmarked. Given the lack of transparency it is not possible for us to assess the reasonableness of the unit rates proposed by other distributors. Key information that is required for us to properly understand and assess the comparability and reasonableness of the AER's benchmark unit rates includes:

- how the proposed unit rates are derived, including whether the proposed unit rates are based on third party quotes or internal analysis, and if quoted, the date of the quote and duration of the contract period;
- the meter volume assumptions that underpin the proposed unit rates by meter type, including any minimum meter volume requirements specified in contracted or quoted rates. The Victorian distributors received volume discounts in the contracted unit rates during the AMI roll out program. Our suppliers' quotes provided following the roll out are also subject to minimum meter volumes over the quoted period. Notably, AusNet Services and Jemena proposed that the introduction of meter contestability would not occur until post-2020. Therefore, their proposed meter volumes are higher than if they had assumed meter contestability will be introduced on 1 December 2017 in accordance with the AEMC's final rule determination. Further, different distributors have higher volumes on certain meter type and generally meter suppliers provide volume discounts on higher volume meter types;
- the foreign exchange rate assumptions used to convert meter hardware prices from USD to AUD. Small differences in the foreign exchange rate assumptions of the different distributors can lead to large differences in the proposed unit rates; and
- whether the proposed unit rates are inclusive or exclusive of the NIC. As noted above, our proposed unit rates are inclusive of the NIC. We cannot confirm whether this is the case for Jemena and we assume it is not the case for AusNet Services due to the different communications technology. Other distributors may have chosen to allocate the costs of the NIC to communications capital expenditure rather than meter unit rates.

Further, our proposed meter unit rates reflect the efficient and prudent costs of operating a metering service in accordance with our regulatory obligations. For the purposes of the AMI roll out program, we undertook a competitive tender process to select our meter providers. The tender process was designed jointly with Deloitte and was independently audited by Portland Group. From this tender process we selected two meter providers, Secure Australasia and L+G. The contractual arrangements with both vendors were independently reviewed and audited for quality assurance purposes by KEMA. Following expiry of the original contract period on

31 December 2015, we now have the option to extend the contract terms and determine the optimal mix of meter volumes from each vendor, taking into account price and service performance, to achieve the most efficient outcome.

<u>Meter replacement installation costs</u>

We dispute the AER's preliminary determination to reject our meter replacement installation costs and substitute for the field time to undertake a new meter connection multiplied by the field labour rate for business-hours excluding on-costs.

The labour time taken to replace a meter is longer than a new connection because:

- travel time to a fault cannot be coordinated to maximise efficiencies. Fault calls are responded to reactively while new connections can be planned to minimise travel time;
- we do not know the cause of the fault until arriving on the site, therefore we action a network fault response which involves sending a fault truck and crew to the site;
- upon arriving on site, we need to ensure the site is safe, including isolating the supply point and replacing the service fuse; and
- following the completion of safety procedures, we need to identify the cause of the fault, e.g. whether the fault is due to a faulty meter, faulty wiring or the meter board.

The AER has provided no evidence to support its statement that the time for undertaking a new connection exceeds that of a meter replacement. Notably, the AER has only included the field time for a new connection and excluded, without reason or explanation, the back-office costs. The table below sets out the difference in our proposed labour time for a meter replacement and the AER's preliminary determination which is based on our field time for a new connection (i.e. excluding back-office time).

We also disagree with the AER that the labour time to complete a meter replacement is equivalent across all meter types. More complex meter installations (such as three phase CT meters) involve more complexity in terms of the activities involved in meter removal and replacement, for example, wiring complexities. Nevertheless, we have revised our modelling approach to apply an average meter replacement time across all meter types, as shown in the table below.

While the AER states that it applied our proposed field worker labour rate, its modelling indicates it has the only applied the business-hours labour rate and has excluded on-costs. We disagree with the AER's substitution of our meter replacement labour rates with our new connections field labour rate for business-hours and excluding on-costs. The labour rate for meter replacements must take into account the fact that meter faults do not necessarily occur during business-hours. Based on our actual meter data between January and October 2015, 16.4 per cent of meter faults occurred after-hours. We also dispute the exclusion of on-costs from our labour rates. As noted above, we ran an efficient low cost AMI roll out program and our on-costs reflect the efficient costs of operating a metering business. The AER has provided no reasons or evidence to support its decision to exclude on-costs from our labour unit rates.

The AER has erred in its presumption that meter replacements are equivalent in labour time and labour unit rates to new meter connections for the reasons set out above. The AER's preliminary determination is inconsistent with the Rules because it results in less capital expenditure than reasonably required of an efficient and prudent service provider to provide metering services.

The table below compares our proposed meter installation costs, broken down by labour unit rate and replacement time, with the AER's preliminary determination.

Table 14.2 Meter replacement costs

	Revised Proposal	AER Preliminary Decision	% change
Meter replacement labour rate per hour, $ 2015	165.73	121.49	-27
Average labour time to replace meter, hours	2.92	1.87	-36
Average labour cost to replace a meter, $ 2015 (direct cost)	484.40	227.56	-53

Source: CitiPower; AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015 - Metering capex model.

Our revised regulatory proposal

Meter volumes

For our revised regulatory proposal we assume metering contestability is introduced in Victoria on 1 December 2017 in accordance with the AEMC's final rule determination. We therefore propose meter volumes for:

- new connections from 1 January 2016 to 1 December 2017;
- reactive meter replacements from 1 January 2016 to 31 December 2020;
- proactive meter replacements from 1 January 2016 to 1 December 2017; and
- customer initiated upgrades from 1 January 2016 to 1 December 2017.

Our revised regulatory proposal meter volumes are provided in the table below.

Table 14.3 Meter volumes assuming metering contestability is introduced on 1 December 2017

	2016	2017	2018	2019	2020
New connections	6,216	4,465	-	-	-
Reactive replacements	1,017	1,029	1,035	1,026	1,017
Proactive replacements	807	-	-	-	-
Customer initiated upgrades	347	304	-	-	-
Total meters	**8,387**	**5,798**	**1,035**	**1,026**	**1,017**

Source: CitiPower

At the time of submitting our revised regulatory proposal, we are not aware of any other changes to the Rules that would result in an alternative date for the introduction of meter contestability in Victoria. We note however that should there be amendments to the Rules or AMI OIC to delay the introduction of metering contestability in Victoria beyond 1 December 2017, we have not proposed adequate capital expenditure to continue to install new meters or undertake meter replacements or upgrades. We therefore provide in the table below our forecasts of meter volumes that would be required if metering contestability was deferred in Victoria. We expect the AER to apply the meter volumes that best reflect the knowledge it has available regarding the introduction of metering contestability in Victoria at the time of making its final determination.

Table 14.4 Substitute meter volumes if metering contestability is deferred in Victoria

	2016	2017	2018	2019	2020
New connections	6,216	4,871	4,905	4,939	4,974
Reactive replacements	1,017	1,029	1,036	1,043	1,051
Proactive replacements	807	-	-	-	-
Customer initiated upgrades	347	332	327	323	319
Total meters	**8,387**	**6,232**	**6,268**	**6,306**	**6,344**

Source: CitiPower

Meter purchase

For our revised regulatory proposal, we maintain our position that our unit purchase costs should be based on our actual quoted and contracted unit rates.

In November 2015, we sought updated quotes from our two meter providers for the 2017 to 2020 period given the small change in our revised proposal meter volumes. Our meter providers confirmed our quoted unit rates in USD used in the initial regulatory proposal remain valid for the forecast period.

We have updated our revised proposal unit rates in AUD for updated USD to AUD exchange rate forecasts prepared by Jacobs.[1100]

Meter replacement installation costs

For our revised regulatory proposal, we maintain our position that our proposed meter replacement costs reflect the efficient and prudent costs of providing metering services.

Our revised meter replacement installation costs are based on:

- our actual meter replacement time averaged across all meter types; and
- our labour unit rate for a meter replacement which is a weighted average of the business-hours and after-hours labour rate, and is inclusive of on-costs.

14.2.2 Communications network

Initial regulatory proposal

We forecast capital expenditure in the 2016–2020 regulatory control period for:

- augmentation of the communications network to accommodate new meter connections in 2016, including infilling the network due to supply abolishments and extending the network to achieve communications from non-communicating sites;
- replacement of back-up batteries in communications devices, which have a five year expected life; and
- replacement of faulty communications devices.

For each of the above categories, we forecast:

[1100] Jacobs, *Escalation Indices Forecast, 2016–2020, CitiPower,* November 2015, p. 7.

- the unit cost of communications devices and back-up batteries based on quotes from our service provider, Silver Spring Networks Pty (**Silver Springs Networks**), which we converted to AUD;
- labour hours based on historic average number of labour hours incurred installing communications devices and batteries;
- hourly labour rates based on our current labour rate escalated for real price growth; and
- fault rates for communications devices based on average fault rates in 2013 and 2014.

AER's preliminary determination

The AER's preliminary determination accepted our proposed communications network capital expenditure.

Our revised regulatory proposal

We have maintained our approach to forecasting communications network capital expenditure for the 2016–2020 regulatory control period. We have updated our forecast to:

- include augmentation for new metering connections between 1 January 2017 and 1 December 2017, to reflect the AEMC's final Rule change on the date for the introduction of metering contestability; and
- revised our foreign exchange rate forecast to better reflect current market forecasts.

14.2.3 Information technology

Initial regulatory proposal

We forecast IT capital expenditure for:

- software and hardware upgrades associated with UtilityIQ which are required by our communications network service provider, Silver Spring Networks, to ensure continued operation, support and compatibility; and
- security upgrades associated with UtilityIQ and the smart meter communications network required to ensure the security of our smart meter network and associated systems.

AER's preliminary determination

The AER's preliminary determination accepted our proposed IT capital expenditure.

Our revised regulatory proposal

We have maintained our forecast IT capital expenditure for the 2016–2020 regulatory control period.

14.2.4 Total capital expenditure forecast

Our revised regulatory proposal

The table below sets out our revised regulatory proposal capital expenditure requirement for type 5, 6 and smart metering services for the 2016–2020 regulatory control period. A key change in our capital expenditure forecast between our initial and revised regulatory proposals is the timing of the introduction of metering contestability which is now scheduled for 1 December 2017 rather than 1 January 2017.

Table 14.5 Total capital expenditure forecast ($ million, 2015)

	2016	2017	2018	2019	2020
Meters capex	3.5	2.5	1.0	1.0	1.1
Communications network	0.4	0.1	0.1	0.1	0.1
Information technology	0.4	0.6	0.2	0.2	1.0
Total capital expenditure	**4.3**	**3.2**	**1.4**	**1.3**	**2.1**

Source: CitiPower

14.3 Operating expenditure

We proposed a base-step-trend approach to forecast our operating expenditure requirements for the 2016–2020 regulatory control period.

14.3.1 Base expenditure

Initial regulatory proposal

We proposed using actual 2014 operating expenditure as the base level of expenditure as this reflects business as usual operating expenditure.

We proposed adjusting our actual 2014 operating expenditure to remove non-recurrent expenditure associated with:

- manual meter read costs that are permitted to be recovered directly from customers in accordance with the AMI OIC from 1 April 2015;
- direct overheads as the move to business as usual metering activity and the introduction of contestability will require fewer overheads; and
- IT systems other than the UtilityIQ system. As discussed in chapter 6, we proposed transferring IT related operating expenditure associated with IT systems other than UtilityIQ to standard control services operating expenditure. We therefore removed IT operating expenditure associated with systems other than UtilityIQ from our base operating expenditure for metering services.

We also proposed adjusting our 2014 operating expenditure for our change in capitalisation policy to ensure our forecast operating expenditure is allocated in accordance with the approved Cost Allocation Methodology.

AER’s preliminary determination

The AER's preliminary determination accepted:

- our 2014 actual operating expenditure as the base level of expenditure for forecasting 2016–2020 expenditure requirements; and
- our proposed removal of non-recurrent expenditure for manual meter reading and direct overheads from 2014 base level of expenditure.

The AER's preliminary determination rejected our proposal to transfer operating expenditure associated with IT systems other than UtilityIQ to standard control services. The AER's preliminary determination classified the IT expenditure we transferred to standard control services as alternative control type 5, 6 and smart meters services.

Our response to the AER's preliminary determination

We accept the AER's preliminary determination to apply our 2014 actual operating expenditure as the base expenditure level for forecasting our expenditure requirements in 2016–2020.

We do not accept the AER's preliminary determination in relation to the value of non-recurrent costs. This is because we have updated the value of the non-recurrent manual meter read costs to reflect the updated number of customers eligible to pay manual meter charges.

We dispute the AER's preliminary determination to classify IT operating expenditure for IT systems other than UtilityIQ as alternative control type 5, 6 and smart metering services for the reasons discussed in chapter 6.

Our revised regulatory proposal

For our revised regulatory proposal, we:

- accept the use of 2014 actual operating expenditure as the base expenditure level;
- update our non-recurrent costs for updated number of customers eligible for manual meter charges; and
- maintain our position that the forecast base level of operating expenditure is based on actual 2014 operating expenditure, less our proposed non-recurrent costs and less operating expenditure occurred in 2014 associated with IT systems other than Utiltiy IQ.

14.3.2 Step changes

Initial regulatory proposal

We proposed a step change for labour costs of testing of current transformer (**CT**) meters to meet our regulatory obligations under the Rules. Under the Rules every CT meter is required to be tested within five years (clause 7.6, schedule 7.3). Our 2014 operating expenditure does not include testing of CT meters as these meters were only installed in 2013 and 2014.

Our proposed step change was based on:

- the volume of CT meters in service; and
- our current labour rate multiplied by testing time per meter of 2.5 hours.

AER's preliminary determination

The AER's preliminary determination accepted our step change because it is required to comply with a regulatory obligation.

Our response to the AER's preliminary determination

We accept the AER's preliminary determination to accept our proposed step change for CT meter testing.

Our revised regulatory proposal

For our revised regulatory proposal, we continue to propose a step change in operating expenditure to meet our regulatory obligation in the Rules to test all CT meters within five years of installation.

14.3.3 Scale escalation

Initial regulatory proposal

We forecast the growth in operating expenditure that would result from the growth in our metering service by:

- for each operating expenditure category, assessing the proportion of operating expenditure that varies with meter volumes; and multiplying by

- forecast net growth in meter volumes over the 2016–2020 regulatory control period. Our forecast net meter volume growth was based on our forecast of residential customer connections prepared by CIE less supply abolishments, which were based on the proportion of abolishments in 2014.

AER's preliminary determination

The AER's preliminary determination rejected our proposed scale escalation for growth in meters. The AER based its decision on a view that the majority of operating expenditure associated with metering are fixed costs, particularly IT and communications operating expenditure.[1101]

Our response to the AER's preliminary determination

We disagree with the AER's preliminary determination that the majority of operating expenditure relates to fixed costs. We note that metering operating expenditure includes customer services, meter maintenance, meter data services, overheads, IT and communications. Notably, our IT operating expenditure is for licencing fees which are directly related to the number of meters and our backhaul communications costs are directly related to the volume of meter data being collected and transmitted via 3G access points which is related to meter numbers. We are therefore unclear on what basis the AER has determined that metering operating expenditure is mostly fixed.

Notwithstanding, given the short timeframe before metering contestability is introduced, we accept the AER's decision to provide no scale escalation for operating expenditure.

Our revised regulatory proposal

For our revised regulatory proposal, we propose no scale escalation to compensate for operating expenditure increases driven by the growth in meter volumes.

14.3.4 Total operating expenditure

Our revised regulatory proposal

The table below sets out our revised regulatory proposal operating expenditure requirements for type 5, 6 and smart metering services for the 2016–2020 regulatory control period.

[1101] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 16-44.

Table 14.6 Total operating expenditure forecast ($ million, 2015)

	2016	2017	2018	2019	2020
Actual 2014 expenditure	9.80	9.80	9.80	9.80	9.80
Reclassification of IT expenditure	-2.91	-2.91	-2.91	-2.91	-2.91
Other non-recurrent	-0.07	-0.56	-0.56	-0.56	-0.56
Change in capitalisation policy	0.17	0.17	0.17	0.17	0.17
Step change for CT meter testing	0.18	0.20	0.20	0.20	0.21
Scale escalation	-	-	-	-	-
Real price growth	0.26	0.35	0.46	0.57	0.68
Total operating expenditure	**7.44**	**7.05**	**7.16**	**7.27**	**7.39**

Source: CitiPower

14.4 Real price escalation

14.4.1 Initial regulatory proposal

We forecast real price growth in our operating and capital expenditure by:

- for each expenditure category, assessing the proportion of expenditure associated with labour, material and contracts; and
- applying the respective labour, material and contracts escalators proposed for standard control services, refer to chapter 4.

14.4.2 AER’s preliminary determination

The AER's preliminary determination rejected our proposed real price escalation. The AER applied zero real price escalation because:[1102]

- operating expenditure is expected to be relatively flat because the distributors will be entering a business as usual phase; and
- any real price changes should be able to be managed through productivity improvements.

14.4.3 Our response to the AER’s preliminary determination

We dispute the AER's preliminary determination. The AER has no basis for considering that there will be zero real price escalation during the 2016–2020 regulatory control period.

The AER argues that there will be no real price escalation because the industry is entering a business as usual phase following the completion of the roll out phase of the AMI program. The fact that we are entering a business as usual phase has no bearing on the growth in real input prices. Growth in real input prices is dependent on supply and demand conditions in the market and labour structure arrangements, including the outcomes of enterprise bargaining agreements (**EBA**).

[1102] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p.16-44.

The AER's preliminary determination to allow no real price growth forecast, when there is a real expectation of growth in wages, does not provide a realistic expectation of the cost inputs required to deliver metering services. As discussed in chapter 4, we are committed to paying our labour resources in accordance with our EBAs. Further, forecasts prepared by Deloitte Access Economic, BIS Shrapnel and CIE all demonstrate an expectation that wages will grow at a faster rate than CPI for all sectors of the Victorian economy and for the Electricity Gas Waste and Water sector in Victoria.[1103]

We dispute the AER's view that any real price growth which occurs should be offset by productivity improvements. By assuming pre-emptive and unsubstantiated productivity improvements to offset any real price growth, the AER's preliminary decision fails to provide a reasonable opportunity for us to recover at least the efficient costs of metering services. The AER has provided no qualitative or quantitative evidence to justify where it expects such productivity improvements to be sourced from.

Importantly, any productivity improvements that do arise during the regulatory control period would be returned to customers through lower operating expenditure and a lower regulatory asset base in the next regulatory control period.

We note that in its submission to the AER, the Victorian Department of Economic Development, Jobs, Transport and Resources (**DEDJTR**) states that it 'expects an additional level of productivity improvement associated with the rollout of smart meters so that the DNSP's customers are able to realise the benefits for their investment in the smart meter rollout'.[1104] It is unclear what operating expenditure related productivity improvements DEDJTR has in mind. As the AER observes, DEDJTR has not identified or quantified the benefits of the AMI program it expects to be realised over the 2016–2020 regulatory control period.[1105] Our response to DEDJTR's proposal is provided in chapter 6 of our revised regulatory proposal.

14.4.4 Our revised regulatory proposal

For our revised proposal we maintain our position that real price escalation should be applied. We have forecast our real price escalation for the 2016–2020 regulatory control period based on:

- for each expenditure category, assessing the proportion of expenditure associated with labour, materials and contracts; and
- applying the respective escalators proposed for each expenditure category consistent with our escalators proposed for standard control services, refer to chapter 4.

14.5 Regulatory asset base

14.5.1 Initial regulatory proposal

To calculate our opening metering Regulatory Asset Base (**RAB**) as at 1 January 2016, we used the AER's approved 2015 charges application model, updated with:

- actual 2014 revenue, operating expenditure and the depreciated value of capital expenditure;
- forecast capital expenditure in 2015 based on our AMI Revised Charges Application dated August 2014; and

[1103] CIE, *Labour price forecasts*, November 2015. Deloitte Access Economics, *Forecast growth in labour costs in NEM regions of Australia*, June 2015. BIS Shrapnel, *Real labour and materials cost escalation forecasts to 2020* - Australia and Victoria, November 2014.

[1104] Victorian Department of Economic Development, Jobs, Transport & Resources, *Submission to Victorian electricity distribution pricing review - 2016–20*, 13 July 2015, p. 8.

[1105] CP- AER, *Preliminary decision, CitiPower distribution determination 2016–20,* October 2015, p. 7-72.

- depreciation of the 2015 opening RAB and forecast capital expenditure in 2015.

We rolled forward the RAB using the Post Tax Revenue Model (**PTRM**).

14.5.2 AER's preliminary determination

The AER's preliminary determination did not accept our opening metering RAB as at 1 January 2016. The AER replaced our actual 2014 capital expenditure with the capital expenditure amount approved in its 2015 AMI charges model, updated for CPI inflation.

14.5.3 Our response to the AER's preliminary determination

We accept the AER's preliminary determination with respect to the opening RAB value.

14.5.4 Our revised regulatory proposal

For our revised regulatory proposal, we have applied the AER's preliminary determination opening RAB value.

14.6 Depreciation

14.6.1 Initial regulatory proposal

We forecast depreciation for the 2016–2020 regulatory control period using the AER's PTRM and applying the standard asset lives of 15 years for smart meters and seven years for communications and IT assets.

14.6.2 AER's preliminary determination

The AER's preliminary determination accepted our proposed methodology.

14.6.3 Our response to the AER's preliminary determination

We accept the AER's preliminary determination to accept our proposed methodology.

14.6.4 Our revised regulatory proposal

For our revised regulatory proposal, we have retained our proposed methodology for calculating depreciation.

14.7 Rate of return

14.7.1 Initial regulatory proposal

We forecast the return on capital for metering services by applying the same rate of return as we propose for standard control services, refer to chapter 10.

14.7.2 AER's preliminary determination

The AER's preliminary determination did not accept our proposed rate of return for the reasons discussed in chapter 10.

14.7.3 Our response to the AER's preliminary determination

We do not accept the AER's preliminary determination for the reasons discussed in chapter 10.

14.7.4 Our revised regulatory proposal

For our revised regulatory proposal we forecast the return on capital for metering services by applying the same rate as our revised proposal for standard control services, refer to chapter 10.

14.8 Tax allowance

14.8.1 Initial regulatory proposal

We calculated our proposed tax allowance using the PTRM. The cumulative tax losses as at 31 December 2015, opening tax assets as at 1 January 2016 and the standard tax lives are sourced from the AER's approved 2015 charges application model, updated with actual 2014 revenue and expenditure. We forecast the value of imputation credits (gamma) to be the same as for standard control services, refer to chapter 10.

14.8.2 AER's preliminary determination

The AER's preliminary determination did not accept our tax allowance. The AER applied our proposed methodology for calculating the tax allowance, except the AER substituted:

- our actual 2014 expenditure with the 2014 AMI approved budget; and
- our proposed value of gamma of 0.25 with a value of 0.40.

14.8.3 Our response to the AER's preliminary determination

We do not accept the tax allowance in the AER's preliminary determination.

We do not accept the AER's preliminary determination to replace our proposed value of gamma for the reasons discussed in chapter 10.

We accept the AER's decision to replace our actual 2014 expenditure with the AMI budget.

14.8.4 Our revised regulatory proposal

For our revised regulatory proposal, we propose the tax allowance be calculated using:

- 2014 expenditure based on the approved AMI charges; and
- the value of gamma proposed for standard control services, as set out in chapter 10.

14.9 Annual revenue requirement

14.9.1 Our revised regulatory proposal

The table below sets out our revised regulatory proposal annual revenue requirement for type 5, 6 and smart metering services for the 2016–2020 regulatory control period. The key change in our annual revenue requirement between our initial and revised proposals is the timing of the introduction of metering contestability which is now scheduled for 1 December 2017 rather than 1 January 2017.

We have calculated the smoothed metering revenue such that in the last year of the regulatory control period smoothed metering revenue is within one per cent of metering revenue requirement. This minimises price volatility in the first year of the subsequent regulatory control period. We propose that the AER apply the same principle in its final determination.

Table 14.7 Revised regulatory proposal - Annual revenue requirement ($ million, 2015)

	2016	2017	2018	2019	2020
Depreciation	12.26	12.88	13.45	12.38	8.47
Return on capital	7.54	6.89	6.16	5.30	4.52
Operating expenditure	7.50	7.11	7.21	7.32	7.43
Tax	-	-	-	-	1.09
Unsmoothed revenue requirement	27.30	26.88	26.82	25.00	21.51
X-factor (%)	19.4	18.0	7.0	7.0	7.0
Smoothed revenue requirement	**32.17**	**26.38**	**24.53**	**22.81**	**21.21**

Source: CitiPower

14.10 Exit fee

14.10.1 Rule requirements

Clause 7 of the AMI OIC sets out the provisions for when an exit fee applies and what the value of the exit fee is to include.

Clause 7.1 states that the exit fee is paid by the retailer to the distributor where:

(a) that retailer becomes the responsible person in respect of a metering installation for a customer with annual electricity consumption of 160MWh or less which, immediately prior to that time, included a revenue meter that is a remotely read interval meter which complies with the Specifications and that has been previously installed by a distributor; and

(b) the responsible person in respect of that metering installation immediately prior to that time was the distributor.

Clause 7.2 requires that the AER must:

determine an exit fee payable to each distributor as referred to in clause 7.1 in such a way that the exit fee enables the distributor to recover in a lump sum which is payable upon the change in responsible person referred to in clause 7.1:

(a) the reasonable and efficient costs of removing the metering installation for which the distributor was the responsible person; and

(b) the unavoidable costs (fixed and variable) that a prudent distributor has incurred or would incur as a result of the metering installation for which it was the responsible person being removed prior to the expiry of the life of that metering installation (which must be assumed to be as set out in clause 4.1(g)), including:

(i) the written down value of the meter (assuming that depreciation is calculated on a straight line basis);

(ii) the proportion referable to that metering installation of the written down value of commissioned telecommunications and information technology systems; and

(iii) a reasonable rate of return on the written down values determined under paragraphs (i) and (ii), calculated using the applicable WACC.

14.10.2 Initial regulatory proposal

In accordance with the AMI OIC, we proposed an exit fee apply to a customer that chooses to replace the meter we installed under the derogation with a competitively sourced meter. Our proposed exit fees are dependent on the year of exit and the type of meter installation.

We proposed the exit fee include:

- recovery of the sunk investment costs - this included the depreciated value of the meter purchase and installation costs and IT and communications assets;
- administrative costs to facilitate meter exit - this included back office processing costs such as data management and the costs of processing and disposing of returned meters; and
- costs to ensure no other customer is made worse off - this included the costs of lost economies of scale due to the customers exit, including a share of fixed operating costs and the costs of infilling the communications network to maintain the ratio of communications assets to National Meter Identifiers (**NMI**).

A key philosophy of our proposed exit fee is that no customer should be made worse off by another customer's decision to exit.

14.10.3 AER's preliminary determination

The AER's preliminary determination did not accept our proposed exit fees.

The AER applied our methodology for calculating the exit fees. However, the AER updated the value of the exit fee to revise the operating and capital expenditure inputs to reflect its preliminary determination on our operating and capital expenditure allowances.

14.10.4 Our response to the AER's preliminary determination

We do not accept the AER's preliminary determination of the value of the exit fee.

We accept the AER's preliminary determination to accept our methodology for calculating the exit fees. However, we have updated the calculation to reflect our revised operating and capital expenditure requirements, as set out in this chapter.

Our proposed exit fees are consistent with clause 7 of the AMI OIC. Our proposed exit fees ensure there is no cross subsidy between metering customers that exit the regulated service and those that remain with the regulated metering service. Our proposed exit fee therefore sends efficient signals to the market by ensuring that the customers face the full economic costs of the decision whether to replace an existing regulated meter installation with a competitively sourced meter installation.

14.10.5 Our revised regulatory proposal

For our revised regulatory proposal we have applied the exit fee values from the AER's preliminary determination.

Table 14.8 Revised regulatory proposal - Exit fees, $ nominal

	2017	2018	2019	2020
AMI 1P	422.01	380.72	338.02	303.05
AMI 3P	505.36	463.62	418.45	380.60
AMI 3P CT	1,222.13	1,218.97	1,221.71	1,229.75
Non AMI NMIs	43.35	45.21	47.15	49.17

Source: CitiPower

Alternative control and negotiated services 15

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15 Alternative control and negotiated services

In its *Framework and approach paper* the Australian Energy Regulator (**AER**) set out its proposed classification and corresponding control mechanisms for our distribution services.[1106] The AER classified these services as either direct control, negotiated or unclassified services. For those services the AER identified as direct control, it further categorised these as either standard control or alternative control services.

This chapter has regard to those services classified by the AER as negotiated or alternative control services (excluding metering services, which are discussed separately in chapter 14). This includes our public lighting services.

Our revised regulatory proposal is consistent with many components of the AER's preliminary determination for alternative control and negotiated services. This includes the total labour rates set out by the AER.

In our revised regulatory proposal, however, we adopt an estimate for labour price growth and the rate of return that differs from those used by the AER. Our reasons for applying these estimates are discussed in chapter 4 and 10.

15.1 Rule requirements

The National Electricity Rules (**the Rules**) require the AER make a number of constituent decisions as part of a distribution determination. The decisions relevant to our alternative control services for the 2016–2020 regulatory control period include the following:

- clause 6.12.1(12) requires the AER make a decision on the form of the control mechanisms for alternative control services, and on the formulae that give effect to those control mechanisms; and
- clause 6.12.1(13) requires the AER make a decision on how compliance with a relevant control mechanism is to be demonstrated.

Unless the AER considers that unforeseen circumstances justify a departure, the form of control and the formulae that give effect to those control mechanisms must be in accordance with those set out in the *Framework and approach paper*.

In regard to negotiated services, the Rules the AER make constituent decisions on:

- the negotiating framework that is to apply; and
- the negotiated distribution service criteria we must apply in negotiating terms and conditions (including the prices for negotiated distribution services).

15.2 Alternative control services (excluding public lighting)

Alternative control services (**ACS**) are those that can be attributed to a particular customer (rather than shared across our entire customer base). We recover the full costs of providing these services through set prices.

15.2.1 Initial regulatory proposal

Our regulatory proposal was developed to be largely consistent with the form of control for alternative control services set out in the *Framework and approach paper*.

[1106] CP PUBLIC ATT 2.1 - *AER, Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016*, 24 October 2014.

Our regulatory proposal also set out our proposed method for developing charges for alternative control services. For fee-based services, we proposed a bottom-up build of costs based on labour, materials and/or contractor costs. For quoted services, our charges are levied on a time and materials basis.

15.2.2 AER's preliminary determination

The AER refers to the service groups previously identified as fee based services and quoted services as a single collective group called ancillary network services.

In its preliminary determination, the AER largely accepted our proposal for ancillary network services. This included applying a price cap form of control to ancillary network services (consistent with the formulae we included in our regulatory proposal), as well as adopting our total forecast labour rates.[1107]

The AER, however, did not accept our forecast escalation of costs. Specifically, the AER did not accept our escalation of total labour rates, nor did it accept our method for calculating our consumer price index (**CPI**) escalator. The AER also adjusted the time we proposed for performing meter accuracy tests (on the basis of benchmark comparison with other distributors).

15.2.3 Our response to the AER's preliminary determination

Consistent with the AER's preliminary determination, our revised regulatory proposal maintains the total labour rates included in our regulatory proposal. The AER accepted that these total labour rates were efficient.

In our revised regulatory proposal, we also apply the AER's assessment in regard to the following:

- the time taken to perform meter accuracy tests—that is, we accept the AER's forecast of the time required to perform single phase meter accuracy tests (one hour), and multi-phase meter accuracy tests (3.5 hours); and
- the AER's approach for calculating the CPI escalator from 2014 to 2015.

We do not accept the AER's approach, however, for the calculation of labour cost escalation. Instead, we have applied the labour price escalators set out in chapter 4 of our revised regulatory proposal. The reasons supporting these escalators are also set out in chapter 4.

15.2.4 Our revised regulatory proposal

Our revised regulatory proposal applies the same method for developing ancillary network service charges as set out in our regulatory proposal (subject to the amendments set out above for meter accuracy tests and CPI escalation). This method is summarised in table 15.1. Further information regarding the unit cost inputs used to calculate the proposed charges for the 2016–2020 regulatory control period can be found in our ACS model.[1108]

Table 15.1 Summary of ancillary network services charges

Component	Fee-based services	Quoted services
Form of control	Price caps on individual services	Price caps on individual services
Method for developing charges	Bottom-up build of costs based on labour and materials	Charges levied on time, contractor and materials costs for each specific quote

[1107] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 16-7.

[1108] CP PUBLIC RRP MOD 1.1, *CP ACS Model.slsx*.

Component	Fee-based services	Quoted services
Labour costs	Labour costs determined based on: • identifying the task(s) involved in performing each service; • quantifying the time that each task will take; • identifying the types of personnel that will be required to undertake each task, based on the skills required; • quantifying the number of personnel that are required to undertake each task; and • applying the applicable labour rate(s)	Labour costs determined based on: • identifying the task(s) involved in performing each service; • quantifying the time that each task will take; • identifying the types of personnel that will be required to undertake each task, based on the skills required; • quantifying the number of personnel that are required to undertake each task; and • applying the applicable labour rate(s)
Materials costs	Materials costs determined based on: • identifying the tasks involved in performing each service; and • identifying the type and number of materials that are required for each task	Materials costs determined based on: • identifying the tasks involved in performing each service; and • identifying the type and number of materials that are required for each task
Contractor costs	Not applicable	Reflects all costs associated with the use of external labour, including overheads and any direct costs incurred

Source: CitiPower

A description of the ancillary network services we propose to apply for the 2016–2020 regulatory control period are set out in table 15.2 and table 15.3.

Table 15.2 Description of fee-based services for the 2016–2020 regulatory control period

Fee based service	Description
Routine connections (customers below 100 amps)	This charge applies when a customer with a supply point with fuses less than 100 amps moves into a new premises and requests supply. Different charges apply depending on whether we are responsible for the meter or not, whether the meter is single or multiphase and whether the service is provided during or after business hours.
De-energisation of existing connections	This charge applies when a request is received to disconnect at a supply point for fuses less than 100 amps by a field visit. This charge includes disconnection for non-payment. This service is only provided during business hours.
Re-energisation	This charge applies when a request is received to re-energise a supply point for fuses less than 100 amps by a field visit. Three options for re-energisation are available: • reconnections (same day) business hours only; • reconnections (including customer transfer) business hours; and • reconnections (including customer transfer) after hours.
Meter investigation	This charge applies when a request is received to investigate the metering at a given supply point. This request may be initiated by either the retailer or a customer. Different charges apply depending on whether the service is provided during or after business hours.
Meter testing	This charge applies when a request is made to test the accuracy of a meter at a given supply point. Different charges apply depending on the type of meter being tested, if it is the first or subsequent meter and whether the meter is single or multi-phase and whether the service is provided during or after business hours.

Fee based service	Description
Special meter reading	This charge applies when a request for a Special Meter Read is to be performed by a field visit outside the scheduled meter reading cycle. Where customers have multiple metering installations, such as farms and units, a separate charge applies to each meter on the property. This service is only available during business hours.
Wasted attendance (not distributor fault)	This charge applies to service truck visits requested where: • the crew arrives to find the site is not ready for the scheduled work within 15 minutes of arriving; • the truck attendance is no longer required once on site; • 24 hours notice is not provided for a cancellation; • the site is locked with a non-industry lock; • asbestos removal or warning on site; • scaffolding obstructing meter position; • non-adherence to VESI SIR's; or • other issues associated with safety assessment of the site. Once the site is ready for the service truck visit another appointment needs to be booked and the normal service truck visit charge applies. Business hours and after hours charges apply where appropriate.
Service truck visits	This charge applies when a service crew is requested for up to an hour in a number of circumstances including: • disconnection of complex site; • reconnection of complex site; • metering additions or alternations; and • shutdowns. While larger scale works will be charged through a quoted service after hours truck by appointment charge, where the job unexpectedly goes above the hourly mark, additional half hourly intervals will be charged up to two hours. Different charges apply depending on whether the service is provided during or after business hours.
Remote meter configuration	This charge applies when a request is received to reconfigure a smart meter and the related infrastructure is in place.
Remote de-energisation	This charge applies when a request is received to de-energise a customer that has smart metering and related infrastructure in place which is then used to disconnect the customer from our network.
Remote re-energisation	This charge applies when a request is received to re-energise a customer that has smart metering and related infrastructure in place which is then used to connect the customer to our network.
Manual meter reading	This charge applies to customers who have elected not to have their manually read meter replaced with a remotely read smart meter.
Customer access to meter data	This charge applies when a request is received: • from a customer more than four times in any given 12 month period; or • from a customer in a different manner or form than specified in the Australian Energy Market Operator (**AEMO**) metering data provision procedures; or • by a customer authorised representative as part of a request for information about more than one customer.

Source: CitiPower

Table 15.3 **Description of quoted services for the 2016–2020 regulatory control period**

Quoted service	Description
Routine connections (customers above 100 amps)	This charge applies when customers above 100 amps request a routine connection.
Supply abolishment (above 100 amps)	This charge applies when customers above 100 amps request a permanent removal of our supply assets. A separate charge applies per site.
Rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting assets	This charge applies when a customer requests capital work for which the prime purpose is to satisfy a customer requirement other than new or increased supply, other than where Guideline 14 is applied. Examples include: • Vic Roads and Council requested asset relocations to allow for new road works; and • customer removal or relocation of service wire to allow work on private installation.
Auditing design and construction	This charge applies when either a third party requests or we deem it necessary to review, approve or accept work undertaken by a third party. Examples include: • customer provided buildings, conduits or ducts used to house our electrical assets; • customer provided connection facilities including switchboards used in the connection of an electricity supply to their installation; • any electrical distribution work completed by our approved contractor that has been engaged by a customer under option two provisions; • provision of system plans and system planning scopes, for option two designers; and • reviewing and/or approving plans submitted by option two designers.
Specification and design enquiry fees	This charge applies when an element of detailed design is required to fairly assess the costs so that an offer for connection services can be issued to a customer. Examples include: • the route of the network extension required to reach the customer's property; • the location of other utility assets; • environmental considerations including tree clearing; and • obtaining necessary permits from State and Local Government bodies.
Elective undergrounding where above ground service currently exists	This charge applies when a customer with an existing overhead service requests an underground service, other than where Guideline 14 is applied.
Damage to overhead service cables caused by high load vehicles	This charge applies to an identifiable third party when overhead service cables require repairing because they have been damaged by high load vehicles pulling down cables.
High load escorts (lifting overhead lines)	This charge applies when a third party requires safe clearance of overhead lines to allow high load vehicles to pass along roads.
Covering of low voltage mains for safety reasons	This charge applies when customers request coverage of powerlines for safety reasons. The charge applied will depend on the time taken to perform the service. Differing charges can arise as a result of the type of line being covered; street mains (two wires or all wire) or service cables.

Quoted service	Description
After hours truck by appointment	This charge applies when a request is received to undertake larger scale works by a service truck. Examples of types of works include: • disconnection of complex site; • reconnection of complex site; • metering additions or alternations; and • shutdowns (includes preparation works).
Reserve feeder maintenance	This charge applies when a customer requests continuity of electricity supply should the feeder providing normal supply to their connection experience interruption. The fee covers the maintenance of the service, it does not include the capital required to implement or replace the service as this is covered in the connection agreement. This service is not available to new customers.

Source: CitiPower

15.3 Negotiated services (excluding public lighting)

Negotiated services include those where all relevant parties have sufficient market power to negotiate the provision of those services. For these services, we negotiate prices directly with our customers according to a negotiating framework established by the Rules.

15.3.1 Initial regulatory proposal

As part of our regulatory proposal, we attached our negotiating framework.[1109] This framework reflected that approved by the AER for the 2011–2015 regulatory control period, but amended to include the additional service classifications set out in the *Framework and approach paper*.

15.3.2 AER's preliminary determination

The AER accepted our negotiating framework for the 2016–2020 regulatory control period, as submitted in our regulatory proposal.[1110]

The AER also retained the negotiated distribution service criteria it published in 2015. These criteria give effect to the negotiated distribution service principles set out in the Rules.

15.3.3 Our revised regulatory proposal

Consistent with the AER's preliminary determination, we propose to apply the negotiating framework for the 2016–2020 regulatory control period as submitted in our regulatory proposal.[1111]

15.4 Public lighting

We operate and maintain public lighting assets throughout our distribution network, and provide public lighting services to local councils and VicRoads.

[1109] See: CP PUBLIC ATT 16.7 - CitiPower, *Proposed negotiating framework, Regulatory control period commencing 1 January 2016*.

[1110] AER, *Preliminary decision, CitiPower distribution determination 2016–20*, October 2015, p. 17-6.

[1111] See: CP PUBLIC ATT 16.7 - CitiPower, *Proposed negotiating framework, Regulatory control period commencing 1 January 2016*.

15.4.1 Initial regulatory proposal

Our regulatory proposal for public lighting applied the service classifications set out in the *Framework and approach paper*.[1112]

On 3 August 2015, however, the AER noted its intention to depart from the classification of all dedicated public lighting services as negotiated services. Specifically, the AER considered that unforeseen circumstances justified its departure from the classification published in its final *Framework and approach paper*. On 14 August 2015, therefore, we submitted a response to the AER that included our revised prices for public lighting services.[1113]

15.4.2 AER's preliminary determination

In its preliminary determination, the AER largely accepted our proposed method for developing public lighting charges. The AER, however, adjusted our charges for the following:

- applied a rate of return consistent with its preliminary determination for standard control services;
- applied a labour price escalator consistent with its preliminary determination for standard control services;
- reduced our general labour rate, and our labour rate per hour for night patrols;
- reduced our urban elevated work platform vehicle per hour cost, and our rural patrol vehicle per hour cost;
- reduced our operating expenditure overhead;
- reduced our average cost per phone call complaint; and
- removed our account management costs.

The AER also made a number of amendments to the public lighting model.

15.4.3 Our response to the AER's preliminary determination

Our revised regulatory proposal adopts the amended unit rates set out in the AER's preliminary determination. We have also removed our account management costs in developing our public lighting charges, consistent with the approach set out by the AER.

We have not applied the AER's approach, however, for the calculation of labour cost escalation. Instead, we have applied the labour price escalators set out in chapter 4 of our revised regulatory proposal. The reasons supporting these escalators are set out in chapter 4.

Similarly, our public lighting charges included in our revised regulatory proposal are based on the rate of return set out in chapter 10 of our revised regulatory proposal. The reasons supporting this rate of return are set out in chapter 10.

15.4.4 Our revised regulatory proposal

Our proposed public lighting charges for the 2016–2020 regulatory control period are set out in our Public Lighting ACS model.[1114]

[1112] CP PUBLIC ATT 2.1 - AER, *Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016*, 24 October 2014.

[1113] CitiPower and Powercor, *Letter to AER, RE: Victorian public lighting reclassification*, 14 August 2015.

[1114] CP PUBLIC RRP MOD 1.7, *CP Public Lighting ACS Model.xlsx*

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Glossary 16

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16 Glossary

Table 16.1 Glossary

Term	Definition
2011-15 final determination	AER’s 2011-15 final determination
2021 RFM	The roll forward model to accompany the AER’s 2021–2025 distribution determination
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACG	Allen Consulting Group Pty Ltd
ACR	Automatic circuit recloser
ACS	Alternative control service
ACSC Threat Report	Australian Cyber Security Centre, 2015 Threat Report, July 2015
ACT	Australian Capital Territory
ACT	Australian Competition Tribunal
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
AMI OIC	Advanced Metering Infrastructure Order in Council
APESMA	Association of Professional Engineers, Scientists and Managers Australia
Application by UED	Application by United Energy Distribution Pty Limited (No 1) [2012] ACompT 1
ARORO	Allowed Rate of Return Objective
ARR	Annual revenue requirement
ASD	Australian Signals Directorate
ASU	Australian Services Union
ASU/APESMA/NUW EBA	Powercor Australia Ltd (ASU; APESMA; NUW) Enterprise Agreement 2013
ATO	Australian Tax Office
AUD	Australian dollar
Assumption 1	The assumption in respect of gamma that all domestic investors are eligible to utilise imputation credits, while foreign investors are not
Assumption 2	The assumption in respect of gamma that eligible investors (i.e. domestic investors) value imputation credits at their full face value because each dollar of imputation credits received can be fully returned to them in the form of a reduction in tax payable

Term	Definition
B2B	Business-to-business
BAU	Business-as-usual
BEE	Benchmark Efficient Entity
BFV	Bloomberg Fair Value
BIS Shrapnel	BIS Shrapnel Pty Limited
BTS	Brunswick Terminal Station
BVAL	Bloomberg Valuation Service
Black CAPM	Black Capital Asset Pricing Model
CAM	Cost allocation methodology
Capex	Capital Expenditure
Capex criteria	Capital expenditure criteria set out in clause 6.5.7(c) of the National Electricity Rules
CatA RIN	Category Analysis Regulatory Information Notice
CBD	Central Business District
CBRM	Condition Based Risk Management
CCA	Competition and Consumer Act 2010 (Cth)
CEG	Competition Economists Group
CEPA	Cambridge Economic Policy Associates
CEPU	Communications Electrical Plumbing Union
CEPU EBA	Powercor Australia Ltd/CitiPower Pty & CEPU Enterprise Agreement 2013-2016
CERT Australia	Computer Emergency Response Team Australia
CESS	Capital Expenditure Sharing Scheme
CGS	Commonwealth Government Bond Securities
CHED Services	CHED Services Pty Ltd (ACN 112 304 622)
CIE	Centre for International Economics
CIS	Customer Information System
CIS OV	Customer Information System – Open Vision
CitiPower	CitiPower Pty Ltd (ACN 064 651 056)
CoAG	Council of Australian Government
Code	Victorian Electricity Distribution Code

Term	Definition
Confidentiality Guideline	AER, Better Regulation Confidentiality Guideline, November 2013
CPI	Consumer Price Index
CRM	Customer Relationship Management
CT	Current transformer
CT meters	meters with current transformers
DAE	Deloitte Access Economics
DAPR	Distribution Annual Planning Report
DEDJTR	Department of Economic Development, Jobs, Transport and Resources
DGM	Dividend Growth Model
Deloitte	Deloitte Touche Tohmatsu
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
DRP	Debt Risk Premium
DUoS	Distribution Use of System
EBA	Enterprise Bargaining Agreement
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity Distribution Price Reset
EGWW	Electricity Gas Water and Waste
2005 ELC Regulations	Electricity Safety (Electric Line Clearance) Regulations 2005
2010 ELC Regulations	Electricity Safety (Electric Line Clearance) Regulations 2010
2015 ELC Regulations	Electricity Safety (Electric Line Clearance) Regulations 2015
ERA	Economic Regulation Authority Western Australia
ERP	Equity Risk Premium
ESCV	Essential Services Commission of Victoria
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
F&A	Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016
FFM	Fama French Three Factor Model

Term	Definition
Frontier Economics	Frontier Economics Pty Ltd
FW Act	Fair Work Act 2009 (Cth)
GDP	Gross Domestic Product
GFC	Global Financial Crisis
GSL	Guaranteed Service Level
GSP	Gross State Product
Guideline 14	Electricity Industry Guideline No. 14 – Provision of Services by Electricity Distributors
Guideline 15	Electricity Industry Guideline No. 15- Connection of Embedded Generation
HI	Health index
HV	High voltage
IC	Incremental cost
IEEE	Institute of Electrical and Electronic Engineering
Incenta	Incenta Economic Consulting
IR	Incremental revenue
IT	Information technology
ITAA36	Income Tax Assessment Act 1936 (Cth)
ITAA97	Income Tax Assessment Act 1997 (Cth)
Jacobs	Jacobs Group (Australia) Pty Limited
JEN	Jemena Electricity Networks (Vic) Pty Ltd
JGN	Jemena Gas Networks (NSW) Ltd
kV	Kilovolt
kW	kilowatt
kWh	Kilowatt hour
Law	National Electricity Law
LGA	Local government area
LPI	Labour price index
LV	Low voltage
MAIFI	Momentary average interruption frequency index
MED	Major event days

Term	Definition
MRP	Market risk premium
MSATS	Market settlement and transfer solutions
MVA	Megavolt ampere
MW	Megawatts
MWh	Megawatt hour
NECF	National Energy Customer Framework
NEFR	National Electricity Forecast Report
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NEO preferable decision	A decision made by the AER that is preferable in respect of contributing to the achievement of the NEO
NER	National Electricity Rules
NERA (UK)	NERA UK Limited trading as NERA Economic Consulting
NEVA	National Electricity (Victoria) Act 2005
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NIC	Network Interface Card
NMI	National meter identifier
NPC	Network Planning Committee
NPV	Net present value
NSP	Network Service Provider
NSW	New South Wales
NSW and ACT merits reviews	Applications for merits review of the AER's distribution determinations for the NSW electricity distributors (Ausgrid, Endeavour Energy, Essential Energy), the ACT electricity distributor (ActewAGL), and the NSW gas distributor (JGN)
NUW	National Union of Workers
Ofgem	Office of Gas and Electricity Markets
Opex	Operating expenditure

Term	Definition
Opex criteria	Operating expenditure criteria in clause 6.5.6(c) of the National Electricity Rules
Order	F-Factor Scheme Order 2011
PEG	Pacific Economics Group, LLC
PNS	Powercor Network Services
PoE	Probability of exceedance
POEL	Private overhead electric line
Powercor	Powercor Australia Ltd (ACN 064 651 109)
PPIs	Producer price indexes
Proposed Bushfire Mitigation Regulations	Electricity Safety (Bushfire Mitigation) Further Amendments Regulations Exposure Draft
PTRM	Post tax revenue model
Public Lighting Code	Victorian Public Lighting Code
PV	Photovoltaic
QCA	Queensland Competition Authority
QLD	Queensland
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
RCM	Reliability centred maintenance
REFCL	Rapid earth fault current limiter
Repex	Replacement expenditure model
Reset RIN	Price Reset Regulatory Information Notice
RFM	Roll forward model
RIN	Regulatory information notice
RIT-D	Regulatory investment test – distribution
RoR	Rate of return
RoR Guideline	AER, Better Regulation, Rate of Return Guideline, 17 December 2013
Rules	National Electricity Rules
SA	South Australia
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index

Term	Definition
SCADA	Supervisory control and data acquisition
SCS	Standard control services
SCER	Standing Council for Energy and Resources
SIR	Service and Installation Rules
SF	Security fee
SL-CAPM	Sharpe-Lintner Capital Asset Pricing Model
SPI	SPI Electricity Pty Ltd
STPIS	Service Target Performance Incentive Scheme
STPIS Guideline	Electricity distribution network service providers, Service target performance incentive scheme
SWER	Single wire earth return
Theta	The value of distributed imputation credits
Tribunal	Australian Competition Tribunal
TSS	Tariff structure statement
UED	United Energy Distribution
UK	United Kingdom of Great Britain
US	United States of America
USD	United States of America dollar
VBRC	Victorian Bushfire Royal Commission
VCR	Value of customer reliability
VESI	Victorian Electricity Supply Industry
VPN	Victoria Power Networks
WACC	Weighted average cost of capital
WMTS	West Melbourne Terminal Station
WPI	Wage Price Index

Source: CitiPower

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Attachments 17

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17 Attachments

Table 17.1 Attachments

Reference	Attachment	Chapter	Confidential
CP PUBLIC RRP ATT 2.1	CitiPower, Confidentiality Claim, January 2016	All	No
CP PUBLIC RRP ATT 2.2	CitiPower, Certification of reasonableness of key assumptions, January 2016	All	No
CP PUBLIC RRP ATT 3.1	SCER, Regulation impact statement limited merits review of decision-making in the electricity and gas regulatory frameworks decision paper, 6 June 2013	3	No
CP PUBLIC RRP ATT 3.2	Application by Energex Limited (No 4) [2011] ACompT 4	3	No
CP PUBLIC RRP ATT 3.3	House of Assembly Hansard, Second reading speech for the National Electricity (South Australia) (New National Electricity Law) Amendment Bill 2005, 9 February 2005	3	No
CP PUBLIC RRP ATT 3.4	Re Application by ElectraNet Pty Limited (No 3) [2008] ACompT 3	3	No
CP PUBLIC RRP ATT 3.5	Re Seven Network Limited (No 4) (2004) ACompT 11	3	No
CP PUBLIC RRP ATT 3.6	Application by Chime Communications Pty Ltd (No 2) [2009] ACompT 2	3	No
CP PUBLIC RRP ATT 3.7	NERA, Economic Interpretation of clauses 6.5.6 and 6.5.7 of the National Electricity Rules, supplementary report, Ausgrid, 8 May 2014	3	No
CP PUBLIC RRP ATT 3.8	HoustonKemp, AER determination for ActewAGL Distribution - contribution to NEO and preferable NEO decision, 13 February 2015	3	No
CP PUBLIC RRP ATT 3.9	HoustonKemp, AER preliminary decision for Energex - contribution to NEO and NEO preferable decision, 3 July 2015	3	No
CP PUBLIC RRP ATT 3.10	HoustonKemp, Economic review of ERA's draft decision, 27 November 2014	3	No
CP PUBLIC RRP ATT 3.11	Farrier Swier Consulting, Economic considerations for the interpretation of the national gas objective, expert report prepared by Geoff Swier for Jemena Gas Networks (NSW) Ltd, 23 May 2014	3	No
CP PUBLIC RRP ATT 3.12	Economic Insights, Regulation of suppliers of gas pipeline services – gas sector productivity, initial report prepared for Commerce Commission, 10 February 2011	3	No
CP PUBLIC RRP ATT 3.13	G Yarrow, M Egan and J Tamblyn, Review of the limited merits review regime: stage two report, 30 September 2012	3	No

Reference	Attachment	Chapter	Confidential
CP PUBLIC RRP ATT 3.14	AEMC, Review of the electricity transmission revenue and pricing rules, transmission revenue: rule proposal report, draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006, February 2006	3	No
CP PUBLIC RRP ATT 4.1	AER, Final decision - appendices, Victorian distribution network service providers, Distribution determination 2011–2015, October 2010	4	No
CP PUBLIC RRP ATT 4.2	Economic Insights, Economic benchmarking of electricity network service providers, 25 June 2013	4	No
CP PUBLIC RRP ATT 4.3	Frontier Economics, Review of AER's preliminary decision on opex input weights, December 2015	4	No
CP PUBLIC RRP ATT 4.4	Pacific Economics Group, LLC, TFP research for Victoria's power distribution industry, December 2004	4	No
CP PUBLIC RRP ATT 4.5	AER, Final decision, SA Power Networks determination 2015-16 to 2019-20, Attachment 7, October 2015	4	No
CP PUBLIC RRP ATT 4.6	DLA Piper, Legal opinion, 16 December 2015	4	No
CP PUBLIC RRP ATT 4.7	Deloitte Access Economics, NSW distribution network service providers labour analysis, final addendum to 2014 report, 28 April 2015	4	No
CP PUBLIC RRP ATT 4.8	SA Power Networks, Revised regulatory proposal 2016-20, 3 July 2015	4	No
CP PUBLIC RRP ATT 4.9	United Energy Distribution, 2016 to 2020 Regulatory Proposal, 30 April 2015	4	No
CP PUBLIC RRP ATT 4.10	Tenix Australia Pty Ltd and ETU power construction maintenance enterprise agreement 2013–2016, 15 October 2014	4	No
CP PUBLIC RRP ATT 4.11	ZNX Pty Ltd - ETU Victorian electricity enterprise agreement 2013, 17 June 2014	4	No
CP PUBLIC RRP ATT 4.12	ZNX Victorian staff enterprise agreement 2014, 3 February 2015	4	No
CP PUBLIC RRP ATT 4.13	SPI PowerNet & SPI Electricity - ASU/APESMA enterprise agreement 2013, 14 October 2013	4	No
CP PUBLIC RRP ATT 4.14	SPI PowerNet & SPI Electricity - ETU enterprise agreement 2013, 30 October 2013	4	No
CP PUBLIC RRP ATT 4.15	SPI PowerNet & SPI Electricity - ETU enterprise agreement 2010-13, 8 November 2010	4	No
CP PUBLIC RRP ATT 4.16	Jemena Asset Management enterprise agreement (VIC) 2013, 23 August 2013	4	No

Reference	Attachment	Chapter	Confidential
CP PUBLIC RRP ATT 4.17	Jemena Asset Management - ETU Victorian electricity enterprise agreement 2013, 12 June 2014	4	No
CP PUBLIC RRP ATT 4.18	Utilities Management Pty Ltd Enterprise Agreement 2014, 19 May 2014	4	No
CP PUBLIC RRP ATT 4.19	AER, Final decision Ausgrid distribution determination 2015–16 to 2018–19, April 2015, Attachment 7	4	No
CP PUBLIC RRP ATT 4.20	Frontier Economics, Review of AER's preliminary decision on labour price growth, December 2015	4	No
CP PUBLIC RRP ATT 4.21	AER, Preliminary decision, AusNet Services distribution determination 2016–20, October 2015, Attachment 7	4	No
CP PUBLIC RRP ATT 4.22	AER, Preliminary decision, Jemena distribution determination 2016–20, October 2015, Attachment 7	4	No
CP PUBLIC RRP ATT 4.23	Deloitte Access Economics, Forecast growth in labour costs in NEM regions of Australia, 23 February 2015	4	No
CP CONFIDENTIAL RRP ATT 4.24	Memorandum of understanding between CitiPower, Powercor and the CEPU, attaching the ETU powerline enterprise agreement 2013–2016 (undated)	4	Yes
CP PUBLIC RRP ATT 4.24	Memorandum of understanding between CitiPower, Powercor and the CEPU, attaching the ETU powerline enterprise agreement 2013–2016 (undated)	4	No
CP PUBLIC RRP ATT 4.25	NERA (UK), Expert report on the allowed rate of change in SA Power Networks' expenditure due to expected inflation in labour costs, 23 June 2015	4	No
CP PUBLIC RRP ATT 4.26	AER, Final decision, SP AusNet transmission determination 2014-15 to 2016-17, January 2014	4	No
CP PUBLIC RRP ATT 4.27	AER, Final decision, Powerlink transmission determination 2012-13 to 2016-17, April 2012	4	No
CP PUBLIC RRP ATT 4.28	Australian Services Union, Log of claims, June 2013	4	No
CP PUBLIC RRP ATT 4.29	Association of Professional Engineers, Scientists and Managers, Australia, Log of claims (undated)	4	No
CP PUBLIC RRP ATT 4.30	National Union of Workers, Log of claims (undated)	4	No
CP PUBLIC RRP ATT 4.31	The Centre for International Economics, Labour price forecasts, 20 November 2015	4, 14	No
CP PUBLIC RRP ATT 4.32	Reserve Bank of Australia, Exchange Rates - Daily - 2014 to current, accessed 18 December 2015: http://www.rba.gov.au/statistics/historical-data.html#exchange-rates	4	No

Reference	Attachment	Chapter	Confidential
CP PUBLIC RRP ATT 4.33	Jacobs, Escalation indices forecast 2016–2020, CitiPower, Material asset price escalation indices forecast, 17 November 2015	4, 14	No
CP PUBLIC RRP ATT 4.34	AER, Explanatory statement, Capital expenditure incentives Guideline for Electricity Network Service Providers, November 2013	4, 14	No
CP PUBLIC RRP ATT 4.35	BIS Shrapnel, Real cost escalation forecasts to 2017, October 2012	4	No
CP PUBLIC RRP ATT 4.36	Access Economics, Forecast growth in labour costs: March 2010 report, March 2010	4	No
CP PUBLIC RRP ATT 4.37	Access Economics, Labour costs indices for the energy sector, April 2007	4	No
CP PUBLIC RRP ATT 4.38	AEMC, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014: Rule determination, November 2014	4, 5, 6	No
CP PUBLIC RRP ATT 4.39	AEMO, Detailed summary of 2015 electricity forecasts , 2015 National Electricity Forecasting Report, June 2015	4, 5	No
CP PUBLIC RRP ATT 4.40	AER, Explanatory statement, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013	4	No
CP PUBLIC RRP ATT 4.41	Armstrong, Combining forecasts, June 2001	4	No
CP PUBLIC RRP ATT 4.42	Borland, Recommendations for methodology for forecasting WPI, October 2012	4	No
CP PUBLIC RRP ATT 4.43	BIS Shrapnel, Real labour cost escalation forecasts to 2017 - Australia and Victoria, November 2012	4	No
CP PUBLIC RRP ATT 4.44	Deloitte, Forecast growth in labour costs: Victoria and South Australia, February 2013	4	No
CP PUBLIC RRP ATT 4.45	Deloitte, Forecast growth in labour costs in NEM regions of Australia, June 2015	4	No
CP PUBLIC RRP ATT 4.46	Deloitte, A response to submissions on AER preliminary decision for a Regulatory Proposal, September 2015	4	No
CP PUBLIC RRP ATT 4.47	Deloitte, Forecast growth in labour costs in Victoria, June 2013	4	No
CP PUBLIC RRP ATT 4.48	BIS Shrapnel, Real labour and materials cost escalation forecasts to 2020 - Australia and Victoria, November 2014	4, 14	No
CP PUBLIC RRP ATT 4.49	AER, Economic Benchmarking RIN for distribution network service providers, Instructions and definitions, November 2013	4	No
CP PUBLIC RRP ATT 4.50	AER, Final decision, AusGrid distribution determination 2015-16 to 2018-19, Attachment 7 - operating expenditure, April 2015	4	No

Reference	Attachment	Chapter	Confidential
CP PUBLIC RRP ATT 4.51	Economic Insights, Response to Ergon Energy's Consultants reports on Economic Benchmarking, October 2015	4	No
CP PUBLIC RRP ATT 4.52	BIS Shrapnel, Outlook for SA Power Networks real internal and external; labour cost escalation and customer connections expenditure forecasts, January 2014	4	No
CP PUBLIC RRP ATT 5.1	CEPA, Review of demand forecasting approaches, December 2015	5	No
CP PUBLIC RRP ATT 5.2	CIE, Maximum demand forecasting for CitiPower and Powercor - 2015 update, July 2015	5	No
CP PUBLIC RRP ATT 5.3	Oakley Greenwood, Metadata analysis of disruptive technologies on CitiPower and Powercor demand forecasts, June 2015	5	No
CP PUBLIC RRP ATT 5.4	CIE, Review of Assessment of forecasts by Darryl Biggar and AER, December 2015	5	No
CP PUBLIC RRP ATT 5.5	CIE, Review of 2015 AEMO Transmission connection point forecasts and methodology, December 2015	5	No
CP PUBLIC RRP ATT 5.6	CitiPower, Tariff Structure Statement 2017–2020, Overview paper, September 2015	5	No
CP PUBLIC RRP ATT 5.7	Oakley Greenwood, CitiPower pricing comparisons, 1995 to 2014, December 2014	5	No
CP PUBLIC RRP ATT 5.8	GHD, AEMO Demand Forecast Review (2015 update), December 2015	5	No
CP PUBLIC RRP ATT 5.9	AEMO, National Electricity Forecasting Report (NEFR) September Feedback Workshops, October 2015	5	No
CP PUBLIC RRP ATT 5.10	AEMO email to CitiPower and Powercor regarding demand forecasting , 17 November 2015	5	No
CP PUBLIC RRP ATT 5.11	Minister for Energy and Resources, Distribution network pricing arrangements, November 2015	5, 6	No
CP PUBLIC RRP ATT 5.12	AER, Preliminary decision, Jemena distribution determination 2016 to 2020, October 2015	5	No
CP PUBLIC RRP ATT 5.13	AEMO, 2015 Transmission connection point forecasting report for Victoria, September 2015	5	No
CP PUBLIC RRP ATT 5.14	AEMO, 2015 NEFR forecasting methodology information paper, July 2015	5	No
CP PUBLIC RRP ATT 5.15	AEMO, 2014 Transmission connection point forecasting action plan, October 2014	5	No

Reference	Attachment	Chapter	Confidential
CP PUBLIC RRP ATT 5.16	AEMO, 2015 Forecast accuracy report 2015 for the 2015 NEFR, November 2015	5	No
CP PUBLIC RRP ATT 5.17	Fan and Hyndman, Forecasting long-term peak half-hourly electricity demand for Victoria, June 2015	5	No
CP PUBLIC RRP ATT 5.18	Fan and Hyndman, Monash Electricity Forecasting Model, June 2015	5	No
CP PUBLIC RRP ATT 5.19	AEMO, 2014 Transmission connection point forecasts for NSW and ACT	5	No
CP PUBLIC RRP ATT 5.20	AEMO, 2015 Transmission connection point forecasts for QLD	5	No
CP PUBLIC RRP ATT 5.21	AEMO, 2015 Transmission connection point forecast for Victoria	5	No
CP PUBLIC RRP ATT 5.22	Ergon Energy, 2015-16 to 2019-20 Reset RIN	5	No
CP PUBLIC RRP ATT 5.23	Energex, 2015-16 to 2019-20 Reset RIN	5	No
CP PUBLIC RRP ATT 5.24	Essential Energy, 2014-15 to 2018-19 Reset RIN	5	No
CP PUBLIC RRP ATT 5.25	Endeavour Energy, 2014-15 to 2018-19 Reset RIN	5	No
CP PUBLIC RRP ATT 5.26	AusGrid, 2014-15 to 2018-19 Reset RIN	5	No
CP PUBLIC RRP ATT 5.27	Actew AGL, 2014-15 to 2018-19 Reset RIN	5	No
CP PUBLIC RRP ATT 5.28	AER, Final decision Ausgrid distribution determination, 2015-16 to 2018-19, Attachment 6, April 2015	5	No
CP PUBLIC RRP ATT 5.29	AER, Final decision Endeavour Energy distribution determination, 2015-16 to 2018-19, Attachment 6, April 2015	5	No
CP PUBLIC RRP ATT 5.30	AER, Final decision Essential Energy distribution determination, 2015-16 to 2018-19, Attachment 6, April 2015	5	No
CP PUBLIC RRP ATT 5.31	AER, Final decision Ergon Energy distribution determination, 2015-16 to 2019-20, Attachment 6, April 2015	5	No
CP PUBLIC RRP ATT 5.32	AER, Final decision Energex distribution determination, 2015-16 to 2019-20, Attachment 6, April 2015	5	No
CP PUBLIC RRP ATT 5.33	AER, Final decision ActewAGL distribution determination, 2014-15 to 2018-19, Attachment 6, April 2015	5	No
CP PUBLIC RRP ATT 5.34	CIE demand model code - Data preparation, adding cogen and wind farms 2015 update	5	No
CP PUBLIC RRP ATT 5.35	CIE demand model code - Data preparation, adding Melbourne water cogen	5	No
CP PUBLIC RRP ATT 5.36	CIE demand model code - Data preparation, append old electricity data	5	No

Reference	Attachment	Chapter	Confidential
CP PUBLIC RRP ATT 5.37	CIE demand model code - Data preparation, append old electricity data to new	5	No
CP PUBLIC RRP ATT 5.38	CIE demand model code - Data preparation, maximum actual demand max cogen coincidence	5	No
CP PUBLIC RRP ATT 5.39	CIE demand model code - Modelling, Average quarterly demand model	5	No
CP PUBLIC RRP ATT 5.40	CIE demand model code - Modelling, max demand model	5	No
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CP PUBLIC RRP ATT 10.152	NERA (2013) Payout Ratio, 2013	10	No
CP PUBLIC RRP ATT 10.153	NERA (2015) Estimating distribution and redemption rates from taxation statistics, 2015	10	No
CP PUBLIC RRP ATT 10.154	Officer (1994) Cost of capital of a company, 1994	10	No
CP PUBLIC RRP ATT 10.155	SFG 2014 QCA gamma, 2014	10	No
CP PUBLIC RRP ATT 10.156	SFG Jemena gamma reply, Feb 2015	10	No
CP PUBLIC RRP ATT 10.157	SFG Jemena gamma submission, May 2014	10	No
CP PUBLIC RRP ATT 10.158	ACT, Application by Energex Ltd, 2010	10	No
CP PUBLIC RRP ATT 10.159	Handley (2015) Advice on the NERA report - taxation statistics, 2015	10	No
CP PUBLIC RRP ATT 10.160	Handley 2014 Advice on the value of imputation credits, 2014	10	No
CP PUBLIC RRP ATT 10.161	Hathaway (2013) Franking credit redemption ATO data 1988-2011, 2013	10	No
CP PUBLIC RRP ATT 10.162	Hathaway (2014) Franking credit redemption ATO data 1988-2012, 2014	10	No
CP PUBLIC RRP ATT 10.163	Lally (2013) Estimation of gamma, 2013	10	No
CP PUBLIC RRP ATT 10.164	Lally (2014) Review of submissions to the QCA on MRP, 2014	10	No
CP PUBLIC RRP ATT 10.165	IPART WACC Update, August 2015	10	No
CP PUBLIC RRP ATT 10.166	Lonergan Edwards Stanmore Coal, 2012	10	No

Reference	Attachment	Chapter	Confidential
CP PUBLIC RRP ATT 10.167	McKinsey - Dobbs, Koller, Lund, Quantative easing, 2014	10	No
CP PUBLIC RRP ATT 10.168	Partington and Satchell, Analysis of criticism of 2015 Determinations, Oct 2015	10	No
CP PUBLIC RRP ATT 10.169	RBA Stevens Speech, 2015	10	No
CP PUBLIC RRP ATT 10.170	SFG, The required return on equity for the benchmark efficient entity, March 2015	10	No
CP PUBLIC RRP ATT 10.171	SFG, Required return on equity for regulated gas and electricity network businesses, June 2014	10	No
CP PUBLIC RRP ATT 10.172	Wright Mason Miles, Cost of capital for regulated utilities in the UK, 2003	10	No
CP PUBLIC RRP ATT 10.173	Wright Smithers, The Cost of Equity Capital for Regulated Companies, 2015	10	No
CP PUBLIC RRP ATT 10.174	Zenner and Junak, Musings on low cost of debt, 2012	10	No
CP PUBLIC RRP ATT 10.175	AEMC (2012) Final-Rule-Determination, 2012	10	No
CP PUBLIC RRP ATT 10.176	Debelle 2015 low yields, 2015	10	No
CP PUBLIC RRP ATT 10.177	ERA ATCO Gas Final, 2015	10	No
CP PUBLIC RRP ATT 10.178	FERC Opinion 531, 2014	10	No
CP PUBLIC RRP ATT 10.179	Grant Thornton 2012, Independent expert report on Oh!media Scheme, 2012	10	No
CP PUBLIC RRP ATT 10.180	Handley, Advice on the Return on Equity, Oct 2014	10	No
CP PUBLIC RRP ATT 10.181	IPART, Review of WACC Methodology, 2013	10	No
CP PUBLIC RRP ATT 10.182	Ernst and Young, Independent expert report for MacMahon Holdings, 2013	10	No
CP PUBLIC RRP ATT 12.1	AER, Errors in distribution determination for CitiPower regarding STPIS, November 2015	12	No
CP PUBLIC RRP ATT 12.2	ACIL Allen, Regulatory Impact Statement, Bushfire Mitigation Regulations Amendment, November 2015	12	No
CP PUBLIC RRP ATT 12.3	Ofgem, Electricity Network Innovation Competition, December 2015	12	No
CP CONFIDENTIAL RRP ATT 14.1	Secure, Proposal for supply of Smart Meters BAU to PNS, August 2014	14	Yes
CP PUBLIC RRP ATT 14.1	Secure, Proposal for supply of Smart Meters BAU to PNS, August 2014	14	No
CP CONFIDENTIAL RRP ATT 14.2	Landis & Gyr, Request for quotation, November 2014	14	Yes

Reference	Attachment	Chapter	Confidential
CP PUBLIC RRP ATT 14.2	Landis & Gyr, Request for quotation, November 2014	14	No
CP PUBLIC RRP ATT 14.3	Energeia, Review of Victorian Distribution Network Service Provider's Advanced Metering Infrastructure 2015 Charges Revision Applications, December 2014	14	No
CP PUBLIC RRP ATT 15.1	CitiPower and Powercor, RE: Victorian public lighting reclassification, 14 August 2015	15	No

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Models 18

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18 Models

Table 18.1 Models

Reference	Folder	Model	Confidential
CP PUBLIC RRP MOD 1.1	Other ACS	CP ACS Model.xlsx	No
CP PUBLIC RRP MOD 1.2	Metering ACS	CP Metering Capex and Opex.xlsx	No
CP CONFIDENTIAL RRP MOD 1.2	Metering ACS	CP Metering Capex and Opex.xlsx	Yes
CP PUBLIC RRP MOD 1.4	Metering ACS	CP Metering PTRM and Exit Fees.xlsm	No
CP PUBLIC RRP MOD 1.5	Metering ACS	CP Metering Volumes.xlsx	No
CP PUBLIC RRP MOD 1.6	Metering	CP AMI Charges Model (2015 Charges Application).xlsx	No
CP PUBLIC RRP MOD 1.7	Public Lighting ACS	CP Public Lighting ACS Model.xlsx	No
CP PUBLIC RRP MOD 1.9	Standard Control	CP 2011-15 RFM.xlsx	No
CP PUBLIC RRP MOD 1.10	Standard Control	CP 2016-20 PTRM.xlsm	No
CP PUBLIC RRP MOD 1.11	Standard Control	CP 2016-20 Depreciation.xlsm	No
CP PUBLIC RRP MOD 1.12	RAB roll forward illustration	CP 2016-20 illustration of RAB roll forward.xlsm	No
CP PUBLIC RRP MOD 1.16	Capex	CP Augmentation Capex.xlsx	No
CP PUBLIC RRP MOD 1.17	Standard Control	CP Capex Consolidation.xlsx	No
CP PUBLIC RRP MOD 1.18	Capex	CP Connections Capex.xlsm	No
CP PUBLIC RRP MOD 1.20	Capex	CP IT capex.xlsx	No
CP PUBLIC RRP MOD 1.53	Capex	CP Material Project - WMTS decommissioning.xlsx	No
CP PUBLIC RRP MOD 1.55	Capex	Accenture Metering Contestability - Impact Traceability Matrix.xlsx	No
CP PUBLIC RRP MOD 1.56	Capex and Opex	CP RIN Compliance Expenditure.xlsx	No
CP PUBLIC RRP MOD 1.33	Opex	CP Decommissioning Step Change.xlsx	No
CP PUBLIC RRP MOD 1.34	Opex	CP GSL Step Change.xlsx	No
CP PUBLIC RRP MOD 1.35	Opex	CP Mobile Replacement Step Change.xlsx	No
CP PUBLIC RRP MOD 1.36	Standard Control	CP Opex Consolidation.xlsx	No
CP CONFIDENTIAL RRP MOD 1.54	Opex	CP Lease Renewals Step Change.xlsx	Yes
CP PUBLIC RRP MOD 1.57	Opex	CP Chapter 5A Step Change.xlsx	No

Reference	Folder	Model	Confidential
CP PUBLIC RRP MOD 1.58	Opex	CP Introduction of Cost Reflective Tariffs Step Change.xlsx	No
CP PUBLIC RRP MOD 1.38	Rate of change	CP Capex Escalators.xlsx	No
CP PUBLIC RRP MOD 1.39	Rate of change	CP Labour Escalation.xlsx	No
CP PUBLIC RRP MOD 1.40	Rate of change	CP Opex Non-Labour Escalation.xlsx	No
CP PUBLIC RRP MOD 1.42	Rate of return	CP Rate of return Illustration.xlsx	No
CP PUBLIC RRP MOD 1.47	STPIS	CP STPIS targets.xlsx	No
CP PUBLIC RRP MOD 1.48	STPIS	CP STPIS incentive rates.xlsx	No
CP PUBLIC RRP MOD 1.51	Demand Forecasts	CIE Forecast results FINAL -sent to AEMO.xlsm	No

Source: CitiPower

Regulatory information notice 19

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19 Regulatory information notice

Table 19.1 Regulatory information notice

Reference	Regulatory template	Confidential
CP PUBLIC RRP RIN 3.4	Operational data	No
CP PUBLIC RRP RIN 5.3	MD Network Level	No
CP PUBLIC RRP RIN 5.4	MD utilisation	No

Source: CitiPower