2016 to 2020 Regulatory Proposal

UNITED ENERGY

30 April 2015

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Table of contents

1. A message from our Chief Executive

I am pleased to present this proposal for the 2016-20 regulatory period that will provide our customers with improved services, access to better technology and a price reduction of approximately $70 in 2016.

We have been providing safe and reliable electricity to the people of east and south-east Melbourne and the Mornington Peninsula for the past 20 years, since we were privatised in 1994.

In that time, we have witnessed enormous changes to the way our community uses the energy we help provide through our network of poles and wires.

We are now seeing more energy efficient appliances driving lower electricity use in households and businesses, reversing a decades' old trend of growing energy consumption from one year to the next. At the same time, we are continuing to strengthen the electricity network to support growing demand for electricity at peak times, during Melbourne's hot summer days and early evenings. Keeping the lights on at an affordable price is now more challenging than ever.

History shows we've done a good job on price. Today, our charges are some 25 per cent lower, in real terms, than they were in 1995. Reliability has also improved, by almost three times over that period. We now manage our network with near real time information from 650,000 interval meters, replacing the old-school pin board we once used to monitor supply.

The Australian Energy Regulator's annual benchmarking report indicates that we are one of the most efficient distributors nationally across a variety of measures, alongside our Victorian and South Australian peers. This has not been an overnight success. As our experience has shown, efficiency initiatives take time to introduce and embed across the business before the full benefits can be realised over time.

We are acutely aware that despite privatised networks in Victoria delivering superior outcomes in terms of cost and performance, electricity affordability is a major issue for our customers. We will deliver real price cuts in the 2016-20 period.

The current period has been one of transforming our business to an operating model that delivers maximum efficiency and performance for our customers and shareholders. We are proud of our record of delivering on the commitments we made five years ago and we intend to build on those achievements over the forthcoming regulatory period.

While 2011-15 was about the transformation of our business internally, to position for the future, the 2016-20 period is focussed squarely on our customers. Our customers have told us that they want better information faster about the performance of the network and the energy choices they make. This means empowering them with access to real time information and data, to give them greater control. Our objective is to make dealing with us an effortless experience for our customers, to give them the information they need to make choices and then to provide opportunities to exercise that choice through technology innovation on our network.

We anticipate continued population growth and urbanisation of the Melbourne metropolitan area, with customers being increasingly reliant on reliable and affordable power for the information and service economy. We believe the grid will retain its primacy in the distribution of energy and that new technologies will add to the complexity of energy supply, as solar PV has done in some areas. The efficient integration and sharing of these technologies in harmony with the grid will enhance customer choice and environmental outcomes.

We look forward to continuing to provide safe and reliable electricity to our community.

I would like to acknowledge and thank our many stakeholders and customer group representatives for the hours they have committed to provide us with input and constructive feedback. Our Regulatory Proposal is undoubtedly better for the exchange of views and ideas that we have shared over the past 12 months.

Hugh Gleeson

Chief Executive Officer
United Energy

2. Proposal snapshot

We set out in Table 2-1 the key elements of our Regulatory Proposal, which we explain and justify in the remainder of this document.

Table 2-1: Regulatory proposal snapshot

Standard control services ($M Real 2015)	2016	2017	2018	2019	2020	Total
Capital expenditure forecast (gross)	246.5	256.2	253.8	226.8	212.1	1,195.3
Customer contributions	17.7	18.1	18.3	18.7	18.5	91.4
Regulatory asset base	2,188.6	2,302.0	2,404.8	2,493.5	2,562.7	n/a
Revenue requirements						
Return on capital (WACC 7.38%)	98.5	104.2	109.6	114.5	118.7	545.4
Regulatory depreciation (forecast)	118.4	130.3	138.1	124.3	128.9	640.0
Operating expenditure (including debt raising costs)	157.7	159.1	159.9	162.6	161.1	800.4
Efficiency benefit sharing scheme (carryover amounts)	3.2	19.3	5.1	0.2	0.0	27.7
Shared assets	(0.5)	(0.5)	(0.5)	(0.5)	(0.5)	(2.7)
Corporate tax allowance (Gamma 0.25)	31.1	31.2	29.7	22.5	24.4	138.9
Annual revenue requirement (unsmoothed)	408.5	443.4	441.7	423.6	432.6	2,149.8
X factor (%)	(7.19)	-	-	-	-	n/a
Forecast energy consumption (GWh)	7,585.3	7,600.2	7,672.6	7,726.1	7,776.5	38,360.8
Alternative Control Services	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
Metering annual revenue requirement (unsmoothed) ($M Real 2015)	50.2	47.9	32.5	29.2	28.0	187.7
Metering x factor (%)	64.6	0.0	0.0	0.0	0.0	n/a
Typical residential Alternative Control Services price impact (currently pays $154) ($ Real 2015)	55.92	55.92	55.92	55.92	55.92	

Price Impact (Standard Control Services and AMI)	2015 $	2016 $	2016 %
Small (LVS1R)	449.04	371.61	(17.24)
Medium (LVM1R)	8,806	9,444	7.25
Large (HVkVATOU)	271,939	291,627	7.24

Service classification and control mechanisms	Service classification	Control Mechanism
Standard control services – network and connection services	Accept AER classification	Accept revenue cap
Alternative Control Services – Types 5, 6 and smart meters – not subject to competition		Accept revenue cap
Alternative Control Services – OMR&R shared public lighting		Accept fee based
Alternative Control Services – ancillary network services and other connection services		Accept fee based
Negotiated services – other public lighting		Accept negotiating framework
Unclassified		Accept not applicable
Incentive schemes		
Efficiency benefit sharing scheme	Accept the AER's Version 2 of the scheme published in November 2013	
Service target performance incentive scheme	(a) If AER accepts our proposed capital expenditure then 5 per cent per annum revenue at risk and targets based on historical 5 year average, otherwise (b) Propose 1 per cent per annum revenue at risk and targets relaxed for additional minutes expected to be incurred.	
Capital Efficiency Sharing Scheme	Accept the AER's Version 1 of the scheme published in November 2013	
Demand Management Incentive Scheme	Accept Part A only of AER's Version 1 of the scheme published in April 2009 – propose DMIA of $6.6 million ($ Real 2015)	
Victorian Government F-Factor Scheme	Participate in the Victorian Government's public consultation process about the scheme.	
Proposed additional pass-through events		
Terrorism event Natural disaster event Insurance cap event Insurer's credit risk event A retailer insolvency event A National Energy Customer Framework event		

3. About our Regulatory Proposal

This is our Regulatory Proposal to the Australian Energy Regulator (AER) for our forthcoming regulatory period, 1 January 2016 to 31 December 2020.

We have developed this Regulatory Proposal following extensive communication and engagement with our customers and other stakeholders. It details, in particular, the revenues that we require to maintain the quality, safety, reliability and security of our distribution services, and of our assets that we use to deliver them.

We have also provided to the AER with this Regulatory Proposal:

- Our Overview Paper that summarises the key elements of our proposal;
- A range of supporting documents and models that provide further detail about our proposal – these are discussed in chapter 27; and
- Our responses to the AER's Reset Regulatory Information Notice (RIN).

3.1. Regulatory context

We operate under a distribution licence that is issued by the Essential Services Commission of Victoria (ESCV). This licence sets out the conditions under which we provide services to our customers.

The AER regulates the prices that we can charge for many of our services. Our charges represent about one quarter of the average domestic electricity customer's bill.

In October 2010, the AER made a determination that regulates the prices that we can charge for our services between 1 January 2011 and 31 December 2015.

In November 2012, the Australian Energy Market Commission (AEMC) changed the National Electricity Rules (Rules) under which we are regulated. In November and December 2013, the AER published a series of guidelines that set out its approach to regulation under the new Rules. We have prepared our Regulatory Proposal in accordance with the new Rules and the AER's Guidelines.

The AER's distribution determination will regulate the prices that we can charge for our services for the coming five years. The AER must make its determination in a manner that will, or is likely to, contribute to achieving the national electricity objective. This objective, which is detailed in section 7 of the National Electricity Law (NEL), 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*
>
> *(b) the reliability, safety and security of the national electricity system.*

On 24 October 2014, the AER issued its final Framework and Approach paper for the Victorian distribution network service providers (DNSPs) for the forthcoming regulatory period. This determined the control mechanisms that will apply to our services. The AER also proposed the service classification, incentive schemes, application of the Expenditure Forecast Assessment Guideline and approach to treating depreciation and dual function assets. Section 20 of this Regulatory Proposal details our responses to each of the AER's positions.

There are various other regulatory developments that we have considered in preparing our Regulatory Proposal, including:

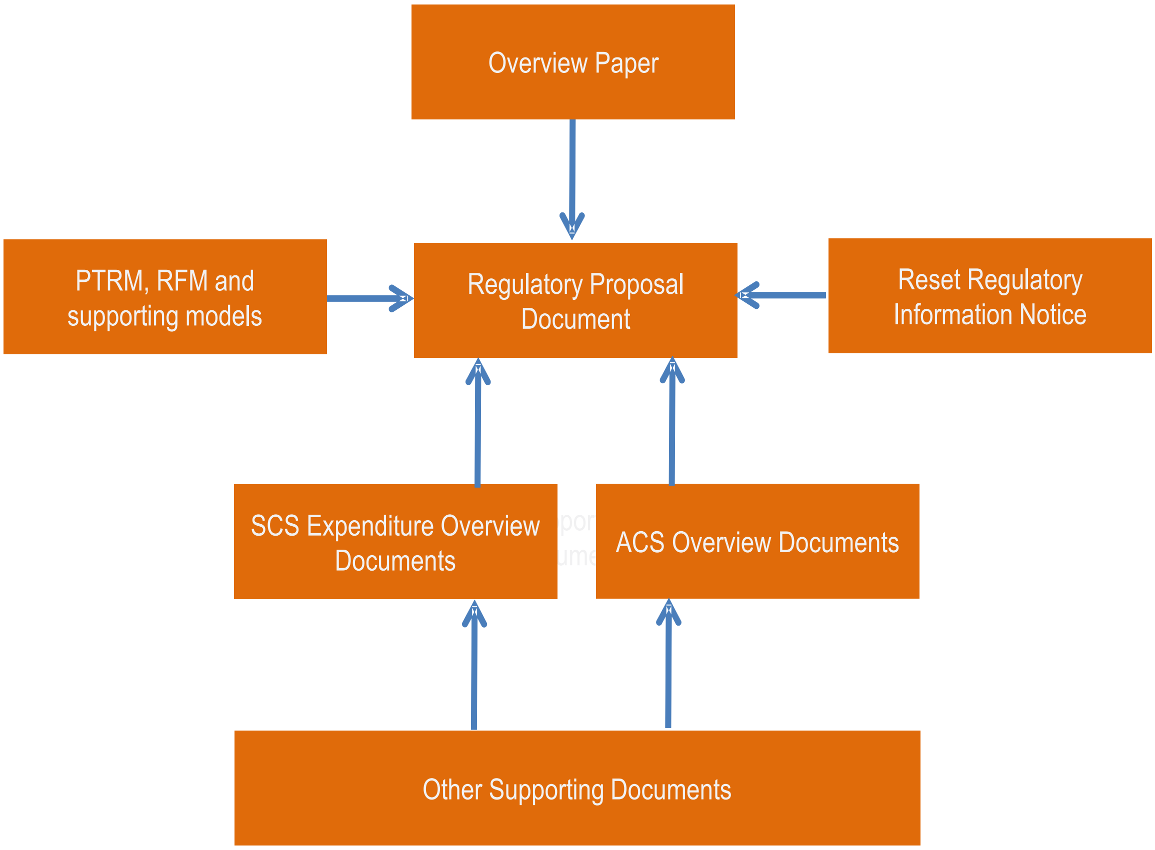
- New Rules that establish a national framework for distribution network planning and expansion, including new demand-side obligations on us which we have adopted and embedded into our network planning processes;
- New Rules that implement the AEMC's Power of Choice review, including to better promote cost reflective pricing;
- New Rules that seek to clarify how the existing expenditure objectives relating to reliability, security, and quality work together;

- The expiry from 31 December 2016 of Victoria's derogation from the Rules under which we are the monopoly supplier of type 5 and type 6 metering in our service area[1];
- New requirements for reporting against various RINs issued by the AER; and
- Amendments to the *Electricity Safety (Electric Line Clearance) Regulations* in response to the Victorian Bushfires Royal Commission (VBRC).

The new Victorian Government does not currently support the move to the National Energy Customer Framework because they consider it would not offer existing consumer protections although there may be some harmonisation or review of Victorian instruments. We propose that any costs arising from the introduction of these reforms be treated as a cost pass through event in the forthcoming regulatory period. This is discussed further in chapter 16.

3.2. Regulatory Proposal and supporting documents' structure

Our Regulatory Proposal is structured as follows to be as clear and accessible to our readers as possible.



[1] The AEMC's Draft Determination on metering competition and related services currently proposes that competition commences from 1 July 2017. We also note that economic regulation of metering provider services transitions from the CROIC to the National Electricity Rules from 1 January 2016.

4. Next steps and our stakeholders' feedback

Our customers and other stakeholders' views on our Regulatory Proposal are important to us. We welcome feedback through any of the following channels:

Channel	Details
Email	yourenergy@ue.com.au
Post	EDPR Feedback PO Box 449 Mount Waverley VIC 3149
Phone	1300 131 689
Online	unitedenergy.engagementhq.com

The AER has indicated that it will invite submissions on our Regulatory Proposal up until 31 July 2015. We will continue to engage with our stakeholders during (and after) this period, including to explain what we have proposed.

The AER indicated in its Framework and Approach paper that it will issue its Preliminary Distribution Determination by 30 October 2015. We will set our prices for our distribution services for the 2016 calendar year based on this Determination.

We will then submit our Revised Regulatory Proposal to the AER by 30 January 2016 and the AER will issue its Substitute Distribution Determination by 30 April 2016. We will deal with any differences between the AER's Preliminary and Substitute Determinations that affect our allowed revenues for 2016 through a revenue 'true-up' from 1 January 2017.

5. Business Overview

This chapter provides an overview of our business and the customers we serve. We also highlight our operating environment, our vision and the key challenges ahead.

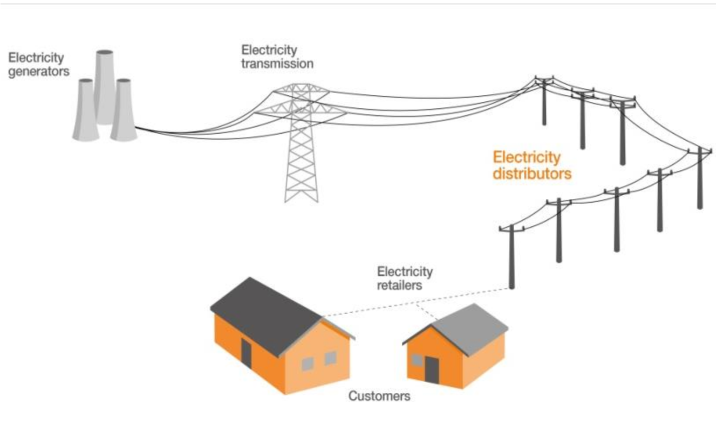
5.1. About us and our network

We distribute electricity to approximately 665,000 customers across east and south-east Melbourne and the Mornington Peninsula over an area of 1,472 square kilometres. The distribution network we construct, operate and maintain transforms electricity from sub-transmission voltages to distribution voltages for supply to our customers. Currently, our distribution network comprises 47 zone substations, approximately 215,000 poles, 13,700 distribution substations, 10,100 kilometres of overhead power lines and 2,800 kilometres of underground cables.

Although our service area is geographically small (about one per cent of Victoria's land area), it accounts for around one quarter of Victoria's population and one fifth of Victoria's electricity maximum demand.

Our distribution area can be generally separated into three parts:

- The northern part of our service area is a developed urban region in metropolitan Melbourne, comprising predominantly residential and commercial centres such as Box Hill, Caulfield, Doncaster and Glen Waverley, and light industrial centres such as Braeside, Clayton, Heatherton, Mulgrave and Scoresby;
- The central part of our service area is a mix of developed and undeveloped land and includes the industrial and commercial centre of Dandenong, which is Victoria's manufacturing heartland in the south-east of Melbourne. Dandenong and the adjacent suburb of Keysborough are our largest growth area for new residential and industrial development; and
- The southern part of our service area comprises Frankston and the Mornington Peninsula. Frankston is one of the largest retail areas outside the Melbourne central business district (CBD). The Mornington Peninsula has a large retirement population and significant holiday use with a coastal boundary of over 190 kilometres.



As a business, we have come a long way since the State Electricity Commission of Victoria was privatised in 1994 and the Victorian Government established Victoria's current electricity industry structure and a new regulatory framework. United Energy Limited was formed originally as a distributer and retailer, but sold its last interest in the electricity retail business in 2002. In 2003, we were restructured and delisted from the Australian Stock Exchange. United Energy Distribution Holdings Pty Ltd was established as a new holding company, with DUET holding 66 per cent equity and Alinta Ltd holding the remaining shares. The majority of our operations were outsourced to Alinta Asset Management, which in turn was purchased by Singapore Power in 2007. DUET continues to hold majority (66 per cent) ownership with the remaining 34 per cent owned by SGSP (Australia) Assets Pty Ltd (SGSPAA). DUET is a large Australian infrastructure specialist fund and SGSPAA is a joint venture between the Singapore-based Singapore Power Limited (SP) and the Chinese-backed State Grid Corporation of China (SG).

We do not generate electricity or sell it to customers. Rather, electricity is produced by generators in the National Electricity Market (NEM) and is transported (in most part) through the transmission network into our distribution network.

Since the restructuring and disaggregation of the electricity industry in the early 1990s, retailers have acted as the custodians of the customer relationship, with distribution being part of the supply chain that is not highly visible to customers. However, this model is changing, as customers become more engaged and proactive in relation to energy supply and consumption, including with our business and the services we deliver. Technology is also playing an important role by increasing the range of services we can offer to our customers.

5.2. Our customers

Our distribution area has a demographically diverse residential population and a broad mix of commerce and industry. We must understand this diversity if we are to engage effectively with our residential and business customers and deliver the services they want. A brief overview of the characteristics of our residential, commercial and industrial customers is provided below, followed by an outline of our approach to engaging with those customers.

5.2.1. Residential customers

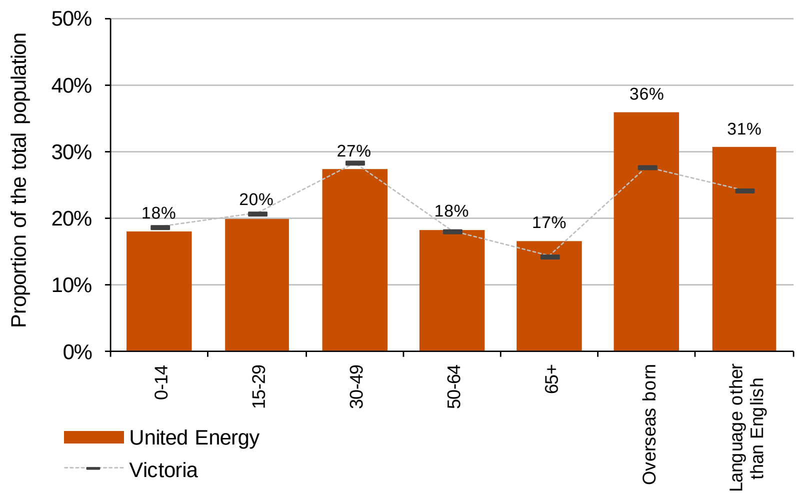
Ninety per cent of our customers are residential.

The chart below presents various demographic indicators expressed as a percentage of our resident population in 2011, benchmarked against Victorian averages.

While the demographic profile of our distribution area generally reflects the Victorian average, notable differences include:

- More older persons: 17 per cent of our resident population was 65 years of age or older compared to the Victorian average of 14 per cent. This difference may in part be attributed to the attractive retirement lifestyle on the Mornington Peninsula; and
- Greater cultural diversity: 36 per cent of our resident population was born overseas compared to the Victorian average of 28 per cent. The cultural diversity of our distribution area is further highlighted by the 31 per cent of people who speak a language other than English.

Figure 5-1: Demographic profile of our service area [2]



[2] Source – ABS and KPMG data

5.2.2. Commercial and industrial customers

Different industries have different electricity consumption patterns. Changes over time in the industry profile of our distribution area therefore impact electricity demand on our network. In broad terms, the composition and trends in our commercial and industrial customer base are similar to Victoria as a whole:

- Manufacturing was once the largest employer in our distribution area, but now comprises 12 per cent of all jobs. However, in line with trends across Victoria, this reflects a significant reduction in the proportion of manufacturing jobs compared with previous years; and
- Professional, scientific and technical services comprise nine per cent of all jobs in our distribution area. This is higher than the Victorian average and an increase on previous years.

Other significant sources of employment include health care and social assistance as well as retail trade. These two industries represent approximately 12 per cent and 11 per cent of total employment in our area respectively.

Our understanding of the diverse characteristics of our residential and business customers positions us to engage effectively with them, so that we can understand our customers' needs and deliver the services that they want.

5.2.3. Customer engagement

We are committed to improving our stakeholder engagement, which means understanding what our customers expect from us and taking action to address their concerns. The following commitment underpins our stakeholder engagement strategy:

> *We will be an outwardly focussed business. We will embed effective stakeholder engagement throughout our operations and develop mature relationships with our stakeholders based on effective two-way communication and understanding.*

Our objective in adopting this approach is to place customers at the centre of our business. An important part of this cultural change is reflected in our goal of providing an effortless customer experience. Further information on what our customers are telling us is provided in Chapter 7, and reflected in our expenditure plans and service performance targets.

5.3. Our operating environment

Our expenditure plans must reflect what our customers are telling us. In addition, we need to address the particular characteristics of our network, manage emerging issues, and meet customers' demand for our services. We briefly discuss some of the key characteristics of our network operations that have a material bearing on our expenditure plans.

5.3.1. Safety and compliance

Safety remains our first and highest priority for our customers, the general public, our staff and contractors. As a Victorian DNSP, we are particularly conscious of bushfire risk and we ensure that our network operations address the recommendations of the VBRC. Our electricity network operations have not contributed to starting a bushfire for almost 10 years.

More broadly, we have significant compliance obligations relating to technical standards, workplace health and safety, electrical safety, the environment and counter-terrorism, and therefore, much of our expenditure is non-discretionary.

In later chapters of this Regulatory Proposal, we provide further details of our compliance obligations, including those that have been recently introduced.

5.3.2. Maintaining reliability to satisfy our customers' needs

We are focused on ensuring that we deliver a standard of service that meets the needs and preferences of our customers. The characteristics of our network asset base - specifically the age of our network assets - has a considerable bearing on the overall reliability we can deliver, as well as on future investment needs.

The age profile of our asset base reflects its historical development. The significant growth in the network during the 1960s and 1970s is now driving increases in replacement capital expenditure (capex), as an increasing number of our assets are reaching end of life. The increasing age of some of our assets contributes significantly to the risk of equipment failure and explains the trend deterioration experienced in our network reliability in recent years.

We will continue to manage our ageing asset base by finding ways to work our assets harder and defer capex and reduce costs to customers where it is safe and efficient to do so. These initiatives include:

- Implementing targeted asset refurbishment programs;
- Enhancing our asset condition assessment and monitoring; and
- Better managing the risk and consequences of asset failures.

However, our expenditure plans for the forthcoming period must also address the impacts of our ageing asset base on the reliability performance of our network. Specifically, our expenditure plans must enable us to deliver network services at a reliability standard that meets the needs and preferences of our customers. We discuss this issue in detail in relation to our forecast capex in Chapter 10.

5.3.3. Responding to customers' changing energy service needs

Our distribution network has been developed over the past century on the basis of two fundamental design assumptions: the predominant flow of electricity is in one direction only, from remote large-scale generators, over wires to end-use customers; and electricity cannot be stored in any significant quantity. Both of these assumptions are now beginning to become invalid, as embedded generation and storage options become more economically viable, and it is expected that this trend will accelerate.

Our distribution network must serve a more empowered and actively engaged customer base, and must accommodate new customer-centric and intelligent energy technologies, more dynamic demand profiles and evolving and complex externalities including climate change and an increasing security threat level. We recognise that a network designed to operate passively to move electricity from the transmission grid to consumers must evolve to support the integration of distributed energy resources and more active demand-side participation.

In particular, our longer term network strategy, as well as our more immediate plans, reflect the impacts of the following key drivers of change:

- Customers have responded to rising energy prices and concerns about climate change and sustainability by using less electricity, buying more energy efficient appliances, and building more energy efficient houses. They also seek to be much more actively engaged in energy decision-making;
- Substantial reforms to the NEM have been made, and more are in-train to promote consumer choice, enable consumers to make better and more informed decisions about energy products and services, promote demand-side participation, enhance consumer access to competitive offers from market participants and support competition in the provision of electricity and demand-side services;
- Development of solar photovoltaic (PV) panel, battery and electric vehicle (EV) technology has accelerated in the last decade, leading to dramatic reductions in the costs of these technologies and a significant increase in their use. This trend is expected to continue, particularly in relation to energy storage technology development;
- Development of Smart Grid technology will enable the network to:
    - Support the intermittent and less predictable renewable energy technologies;
    - Automatically anticipate and resolve faults on the grid; and
    - Continually monitor asset condition to identify the need for maintenance.

It will also enable the use of energy efficient 'smart appliances', which can be programmed to run on off-peak power.

- The interconnectivity of communications and control devices due to Smart Grid technology and the increased convergence with the corporate and operational information technology networks, raises new risks around physical and cyber security. Understanding these risks and responding with new security measures will be essential for the efficient and reliable on-going operation of the electricity network.

We are committed to ensuring that we are positioned to respond positively to the changing requirements of our customers, changes in technology and markets and changes in community and government expectations, so that we can provide services that our customers value highly. Against the backdrop of this dynamic environment, we must continue to develop our network efficiently to meet peak demand for the forthcoming regulatory period, as explained below.

5.3.4. Demand

We operate within the constraints of a regulatory environment determined by the Rules. Our network planning activities are governed by the Distribution Network Planning and Expansion Framework as prescribed in Chapter 5 Part B of the Rules.

We plan our network to facilitate meeting forecast peak demand by investing in network or non-network options when they become economically efficient. Peak demand forecasting is a key component of the network planning and development process as it is used to determine emerging network limitations and timing for augmentations based on credible growth scenarios.

Peak demand forecasting can be challenging due to its dependency on a number of factors such as retail electricity prices, economic growth, population growth, weather patterns, solar PV panel installations, government policy, and demand management.

In our service area, summer peak demand relative to the summer equipment ratings is the key constraint of our distribution network assets. Given the high dependency of peak demand on economic conditions and ambient temperature, our maximum demand forecasts are developed under three economic scenarios and three ambient temperature conditions. Our Augmentation capex is directly related to the forecast peak demand. Therefore, prudent network planning requires that reliable peak demand forecasts are derived and reconciled using appropriate forecasting models.

In formulating our peak demand forecasts, we have regard to the impacts of disruptive technologies such as solar PV generation installed within our network. At present, there is approximately 100 megawatt (MW) of solar PV capacity connected to our network. We explicitly model these disruptive technologies as post-model adjustments applied to our peak demand forecasts.

Economic growth, population increases and higher penetration of temperature sensitive loads such as air-conditioning units over the last 15 years have been the major drivers for peak demand growth in our service area. Slowing peak demand growth in recent years has been primarily attributed to electricity price rises, low growth economic conditions and, to a lesser extent, the impact of solar PV installations and customer-implemented energy efficiencies.

We have been employing probabilistic planning practices in our network planning process for 20 years. This has delivered an efficient, highly utilised network at relatively low network prices for the benefit of all our customers. Our good track record in the area of Augmentation capex has delivered the highest utilised network in Australia according to AER benchmarks. This demonstrates our forecasting of maximum demand and our Augmentation capex programs are best practice relative to our peers.

In evaluating the capacity and investment needs of the network, it is important to distinguish between:

- Peak demand, which determines the network capacity that we provide at peak times in order to maintain a continuous supply of electricity to our customers; and
- Annual energy consumption, which refers to the total energy throughput during the year.

While our annual energy consumption declined modestly over the past five years our peak demand has grown on average over the current regulatory period. As explained in Chapter 9, in the forthcoming regulatory period we expect growth in peak demand to return to its long-term trend as electricity prices stabilise. Our forecast of Augmentation capex in Chapter 10 explains that our network can accommodate this increased demand with reduced levels of Augmentation capex.

5.4. Our corporate vision

Our vision is to create the *Intelligent Utility* to meet the energy needs of our customers now and into the future. We will achieve this by focusing on industry leadership and innovation and working in the best interests of all our stakeholders.

We are thinking about what our customers will want from energy in five, 10, 20 and 50 years from now. As the Intelligent Utility, we will give our customers access to the best technology and the most advanced network, with a priority on efficiency and on building our reputation by meeting current and future requirements.

Our customers and stakeholders have high expectations about the level of service we provide; the focus we have on distributing safe and reliable energy; the value we deliver for them; and how we respond to their needs, individually and as a community. These expectations are reflected in our values – safety, accountability, collaboration, communication, winning culture, empowerment and respect – which guide us in everything we do.

5.5. Responding to our long term challenges

The key challenges we face in the forthcoming regulatory period and beyond are to:

- Respond to customers' changing needs and expectations;
- Leverage our advanced metering infrastructure (AMI) technology to maximise benefits to customers;
- Continue our strong focus on safety;
- Maintain the reliability of our network in accordance with the needs and preferences of our customers; and
- Reform our network tariffs to better signal the costs of providing network services to our customers, as part of a suite of solutions to more effectively manage peak demand.

Chapter 8 outlines the actions we propose to take in the forthcoming regulatory period to respond to these challenges, in light of what:

- We have delivered to date (Chapter 6); and
- Our customers and other stakeholders are telling us (Chapter 7).

6. What we have delivered

Since we were established 20 years ago, we have delivered significant price reductions to our customers. Today, our charges are some 25 per cent lower in real terms than they were in 1995. This is a great outcome for our customers.

In addition to delivering lower prices than our peers in the NEM, during the current regulatory period, we have successfully:

- Restructured our business so that we can deliver better value to our customers in the future;
- Consolidated our position as a highly efficient business compared to our peers;
- Delivered a level of network service with which customers are generally satisfied, though below our performance targets for the period;
- Completed the rollout of AMI meters, which is already delivering significant benefits to our customers;
- Delivered a number of demand-side initiatives, both internally and with third-party non-network providers; and
- Maintained our focus on safety as our top priority.

Each of these achievements is discussed in turn below.

6.1. Restructuring has delivered benefits and will continue to do so

We pride ourselves on delivering our commitments. Our Regulatory Proposal to the AER for the current regulatory period outlined a strategy to comprehensively transform our business model to:

- Lock in the cost efficiencies we have achieved to date;
- Establish greater business flexibility to best manage future change and risk; and, most importantly
- Deliver a better value proposition to our customers.

The transformation has:

- Delivered cost efficiencies through a hybrid insource/outsource business model, while ensuring that we retain control of strategy and planning;
- Created competitive tension and aligned incentives to deliver cost and service improvements through the division of the network into two regions with separate service providers;
- Built a solid foundation to improve service delivery through the consolidation of our Information and Communications Technology (ICT) systems and the introduction of new ICT and back office providers;
- Positioned the business to realise network benefits from the completion of the AMI rollout that will improve service delivery outcomes with the opening of the Network Control Centre; and
- Brought our strategy and planning functions in-house.

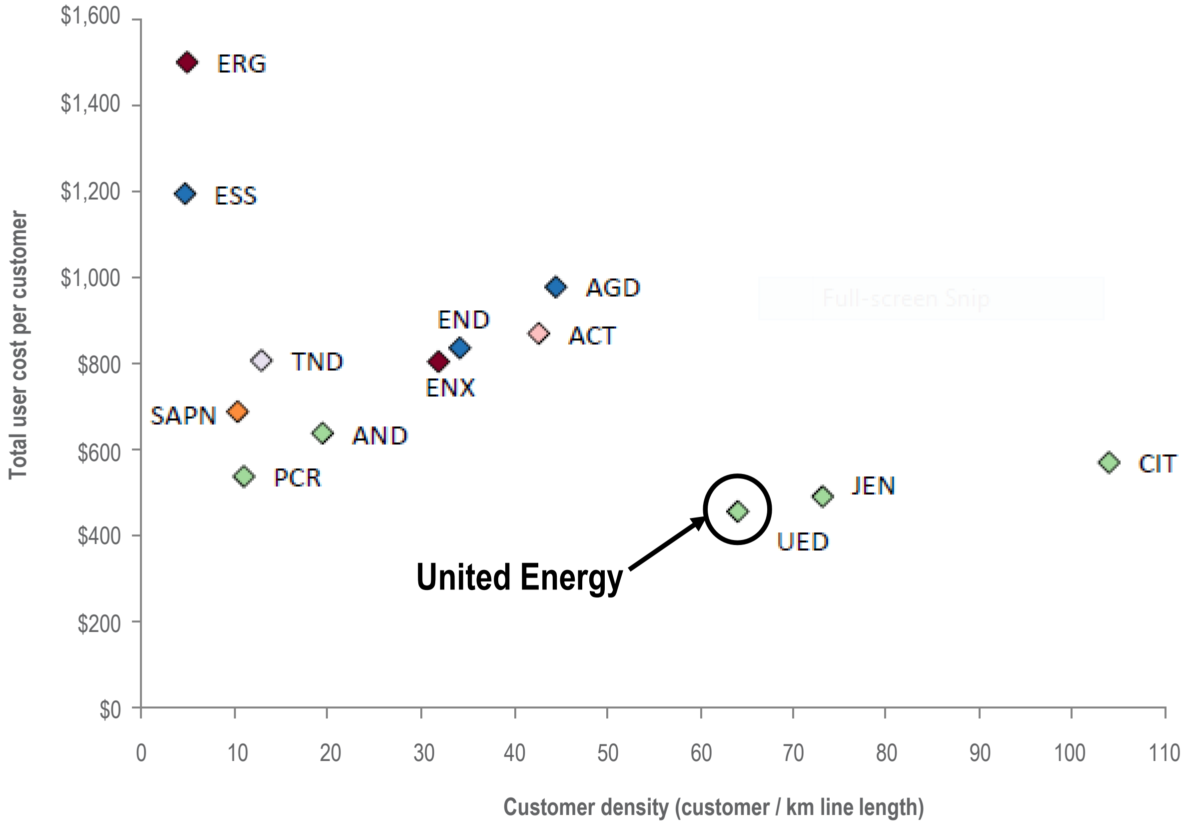
We have been successful in delivering savings in our opex, particularly in the latter stages of this period as the synergies of our new business model have been realised.

Through the transformation of our business over the current regulatory period, we have established a strong team with a proven ability to deliver on our commitments. We will build on this transformation in the forthcoming regulatory period.

6.2. Benchmarking shows that we are an efficient business

Our success in delivering cost efficiencies is best illustrated by the AER's November 2014 Annual Benchmarking Report. Figure 6-1 shows that our average annual total cost per customer is the lowest in the NEM.

Figure 6-1: Average annual total customer cost for 2009 to 2013 against customer density ($2013-14)

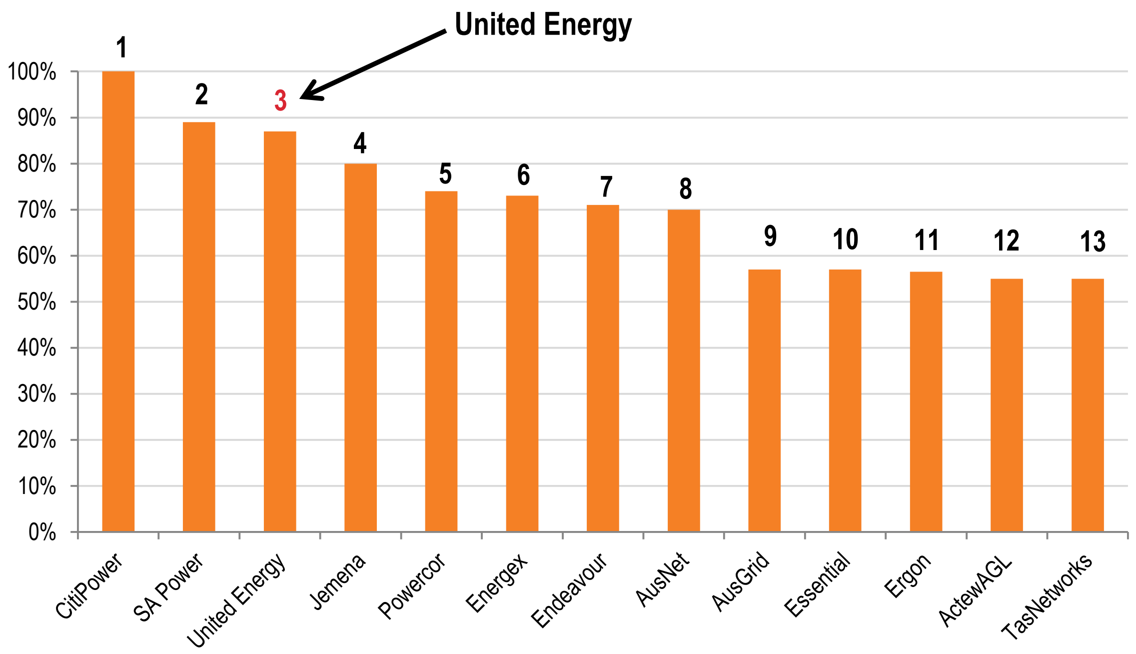


Source – AER's Annual Benchmarking Report, November 2014

We are particularly focused on this benchmark because it shows what customers actually pay. On average our customers pay less than those served by other DNSPs. This outcome vindicates our decision to adopt our new business model and highlights the benefits being delivered to customers.

We also recognise that simple measures such as total cost per customer do not necessarily provide a comprehensive assessment of the overall efficiency performance of a business. The AER's consultant, Economic Insights, has looked at more complex measures of performance such as Multilateral Total Factor Productivity (MTFP), which encompasses both capex and opex performance. According to this analysis (reproduced in Figure 6-2 below), we are the third best performer in the NEM.

Figure 6-2: MTFP Performance (average 2006-2013)



Source – AER, Draft Decision, Ausgrid Distribution Determination 2014-19, Attachment 7: Operating Expenditure, November 2014

This suggests that, over the long-term, we have sustained price and service outcomes to our customers that place us at the efficient frontier of DNSPs in the NEM.

The AER concluded[3]:

> *The MTFP results indicate that, on average, CitiPower, SA Power Networks, United Energy and JEN are the most productive. Ausgrid, ActewAGL, Ergon Energy, Essential Energy and TasNetworks appear to be amongst the least efficient.*

As explained in section 11.3, our efficiency ranking is further improved if the differences in the treatment of overhead costs across all distribution companies are properly taken into account.

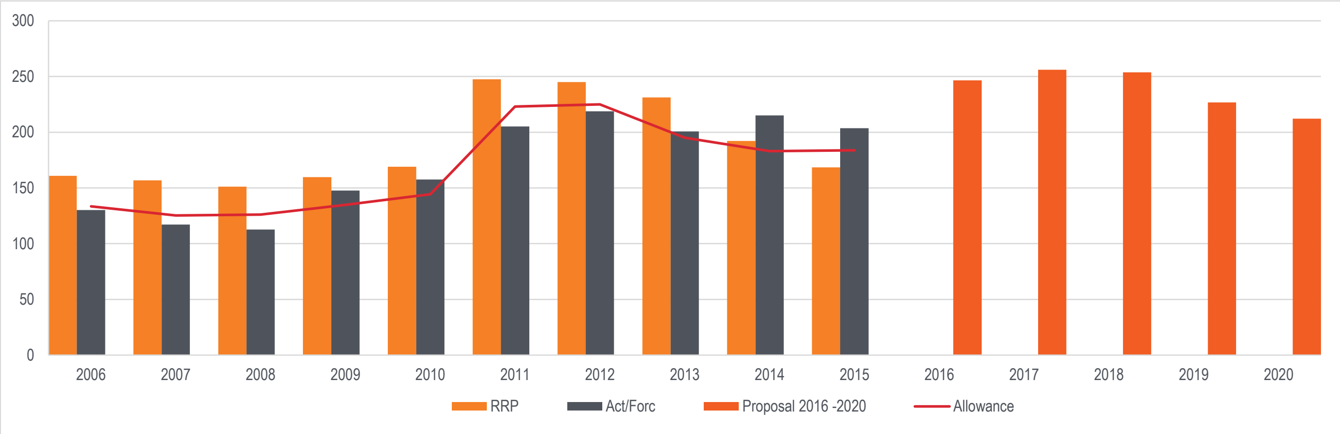
6.3. Capex and network performance targets have been challenging

While we benchmark well against our peers, it has not been possible for us to stay within the AER's capex allowance for the current regulatory period, and we will marginally exceed it over the five years. Although we have delivered on our safety objectives, our increased capex has been insufficient to meet the AER's network reliability performance targets. We anticipate exceeding our capex allowance by $33.5 million[4] (or 3.3 per cent) between 2011 and 2015, as illustrated in Figure 6-3 below.

[3] Ibid, page 57.

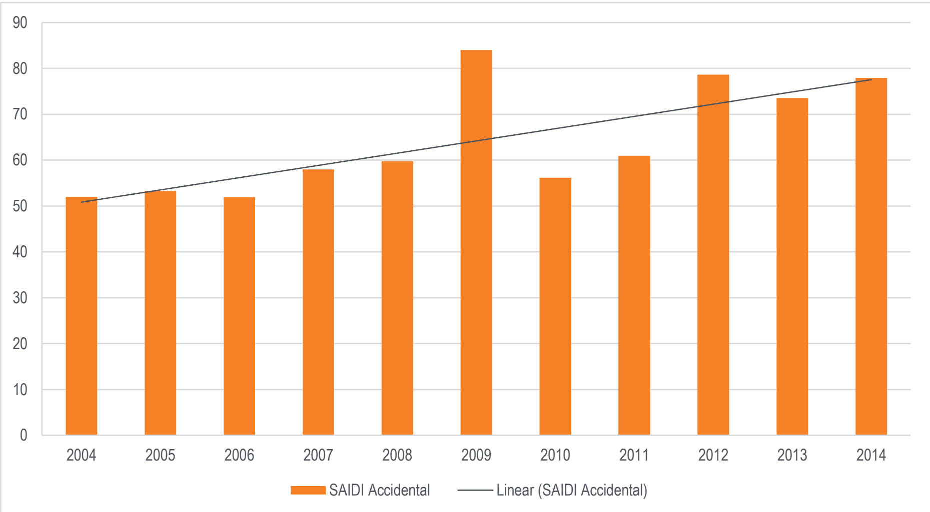
[4] The allowance in 2011 includes equity raising costs of $3.96 million ($, Real 2015).

Figure 6-3: Total capex profile 2006 to 2020 ($M, Real 2015)



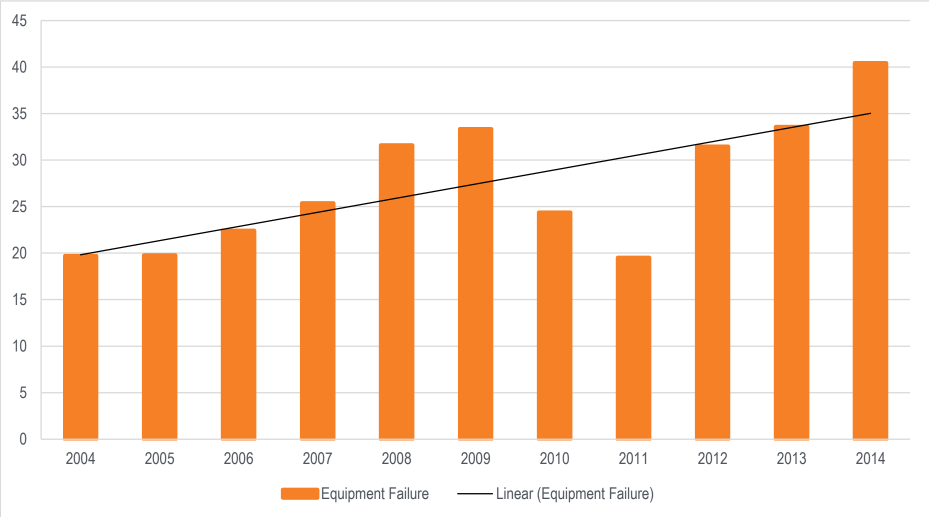
As illustrated in Figure 6-4 below, the reliability trend for our network shows a long-term deteriorating performance in unplanned or “accidental” system average interruption duration index (SAIDI) (excluding major event days) at a rate of 2.6 minutes per year since 2004.

Figure 6-4: Actual and trend unplanned SAIDI



Supply interruptions are caused by a variety of factors, however the single most significant controllable cause for our network over this period is a growing trend in equipment failure. Equipment failure contributed more than half of the deterioration in our unplanned SAIDI, as illustrated in Figure 6-5 below. As further explained in detail in Chapters 8 and 10, we intend to address this challenge in the forthcoming regulatory period.

Figure 6-5: Actual and trend unplanned SAIDI due to equipment failure (minutes)



The deterioration in the reliability performance of our network during the current period has resulted in significant financial penalties for our shareholders under the AER's service target performance incentive scheme (STPIS), and commensurate price reductions for our customers. This is despite the fact that our overall service performance remains substantially better than at the time of our establishment in the mid-1990s. Our research consistently indicates that the vast majority of our customers are satisfied with the current average level of reliability performance of our network.

In the forthcoming regulatory period, we expect to be allowed sufficient capex to meet our performance targets, which are consistent with maintaining the present level of reliability in accordance with the feedback provided to us by our customers. As explained in Chapter 10, we will require increased capex to deliver the standards of service our customers want, and to maintain current levels of reliability, safety and security in accordance with the expenditure objectives set out in the Rules. If our proposed capex is not accepted, then our network performance targets under the STPIS must be relaxed to reflect the trend deterioration in our performance. These issues are discussed further in Chapter 10 and section 15.3, which present our capex forecasts and discuss our performance targets under the STPIS for the forthcoming regulatory period.

6.4. Benefits from our Advanced Metering Infrastructure (AMI) rollout

During the current regulatory period, we completed the rollout of AMI meters in accordance with our best endeavours obligation under the Victorian regulations. An independent audit report for the ESCV found that we had demonstrated a commitment to delivering the AMI program within time, scope, and budget, whilst providing a safe operating environment for staff, service providers and the general public[5].

Given its scale, novelty and complexity, the successful completion of the AMI rollout program is a very significant achievement. However, our key task now is to ensure that the AMI program delivers maximum benefits to our customers. To this end, we have established the *Energy Easy* web portal, which is the first portal in Australia enabling customers to access their energy consumption data in near real time. This secure platform, when teamed with smart meters, enables our customers to understand their electricity use more easily, make more informed energy purchasing decisions, and manage their electricity costs more effectively.

The Energy Easy portal is offered free to all customers who have an AMI meter installed in our network. Specifically, it enables customers to:

- Download their energy consumption in half hourly intervals;

[5] Ernst & Young, Audit of AMI Regulatory Obligations for Distributors, United Energy Distribution Ltd, May 2014, page 6

- View their half hourly energy consumption on a daily, weekly, seasonal and annual basis;
- Compare usage with other customer profiles in their area;
- Set maximum daily consumption reminders;
- Receive emails and text messages for unplanned outages in their area; and
- Pair in-home display devices with their AMI meter.

In addition to providing customers with better access to energy consumption data, AMI is also delivering other significant benefits to our customers, such as:

- Delivering Alternative Control Services at lower cost:
  - More than 54,000 connections and disconnections were completed remotely in 2014. Charges paid by customers for these services have been reduced by more than $30 for each transaction, delivering aggregate savings to customers to date of over $1.6 million for this activity alone;
  - More than 2,300 unnecessary truck visits to customers' premises have been avoided in 2014. The savings to these customers range from $51 to $115 per truck visit – where the higher amount applies to truck visits outside normal business hours;
  - More than 5,000 remote meter reconfigurations in 2014 facilitated data collection of net solar energy exported to our network. Avoided site visits to undertake a meter exchange to a bi-directional meter resulted in customer savings of over $80 for each transaction;
  - More than 1,200 special meter reads were undertaken remotely in 2014 resulting in customer savings of more than $10 per transaction; and
  - The collection of data remotely allows customers to be billed on actual data and avoids estimated bills and associated customer enquiries and complaints.
- Managing the network smarter and safer by:
  - Detecting hazardous 'Loss of Neutral' faults remotely;
  - Undertaking remote neutral integrity testing to avoid site visits and manual testing at around 65,000 premises per annum. This results in an annual savings of approximately $2.6 million;
  - Enhancing our monitoring of supply to life-support customers during storm events;
  - Identifying faults remotely, to avoid wasted truck visits and restore supply more quickly;
  - Having improved voltage data provides us with a better understanding of equipment failure risks and assessment of damage claims;
  - Having improved data on transformer peak load and the likely requirement for transformer upgrades facilitates more efficient use of existing capacity and more efficient investment;
  - Calculating dynamic cyclic ratings for distribution transformers enables us to achieve greater use of the spare capacity in the network;
  - Rebalancing of over-loaded phases enables us to improve network utilisation on peak demand days, and reduce the need for network augmentation;
  - Enhancing load switching enables us to better manage expected high demand days in high network risk areas; and
  - Improving our identification of theft and stolen meters.
- Customers have better access to energy consumption data and a broader range of pricing options:
  - Approximately seven per cent of our residential customers have made use of interval data and have taken up flexible network tariffs;

  - More than 15,000 customers are accessing detailed information on their electricity consumption via our web portal and more recently third party energy agents are seeking access to customer data (with customer consent) in order to provide customers with improved pricing options; and
  - More than 2,800 customers have taken up the use of in-home displays to better understand their energy usage and appliance consumption.
- Facilitating demand-side responses, which will deliver capex savings for our customers. We discuss our recent demand-side initiatives in the next section; and
- Introducing new optional capacity based tariffs for residential customers that will be available from 1July 2015.

We will build on these AMI benefits in the forthcoming and subsequent regulatory periods. Chapter 8 explains our plans for ensuring that the new technology maximises the benefits for our customers.

6.5. Promoting demand-side initiatives

The promotion of demand-side initiatives and non-network solutions to emerging constraints has been an integral part of our business throughout the current regulatory period. Our demand-side engagement has been proactive and well received by our stakeholders.

For example, in 2011 we commenced the District Energy Services Scheme (DESS) Project in conjunction with Manningham City Council. The purpose of this project is to promote demand management opportunities in the Doncaster Hill development area with the aim of deferring the need for network augmentation.

In the summer of 2013-14, we commenced the voluntary Summer Energy Demand (Summer Saver) trial to test customers' responses to financial incentives to reduce maximum demand. The trial was substantially expanded this summer (2014-15), with more than 350 residential customers taking part.

The Virtual Power Plant (VPP) trial was initiated to assess the technical and economic feasibility of installing batteries as an alternative to augmentation of network capacity to meet peak demand. We now have a number of such systems installed and being tested at residential sites on our network.

We have been actively engaged in the debate on reforms to network pricing and in mid-2015 will introduce a voluntary capacity tariff for the first time. One of the objectives of this new tariff is to create price signals that support more effective maximum demand management, in order to reduce the need to invest in network capacity that is called upon for only a few days per year.

In 2014, we signed a two-year network support agreement with GreenSync Pty Ltd for the provision of 1 MW of demand management services in the Chelsea area to defer a planned augmentation. This is an example of a non-network solution being employed to economically defer network investment, reducing total overall costs.

We have been praised by external stakeholders for our high-quality Distribution Annual Planning Report (DAPR) and the level of detail it contains. This report, along with the zone substation metering data we publish, provides interested parties with the information they need to formulate non-network alternatives. We have held public forums each year to facilitate a two-way discussion on the outcomes of the annual planning process and the contents of our DAPR.

We have developed an interactive Google Earth map displaying our network capacity constraints, developed in consultation with local councils. The map can be used to identify suitable locations for non-network solutions.

We have signed eight memoranda of understanding (MoUs) with non-network providers to undertake joint planning activities for developing non-network alternatives. This is complemented by our Demand-Side Engagement Register which currently holds the contact details of 78 individuals from 44 organisations. These individuals receive correspondence on all our network planning and expansion engagement activities and publications.

We have established close working relationships with local government councils. We held a forum in early 2015, which was attended by all councils in our service area. The cross-sector planning opportunities identified included:

- Mapping areas of development to further improve the accuracy of our peak demand forecasting;

- Councils facilitating the promotion of our demand management initiatives and alignment with their sustainability programs;
- Developing council-led non-network solutions;
- Facilitating planning approvals and identifying suitable land for both network and non-network solutions; and
- Councils facilitating non-network initiatives when approached by third-party organisations specialising in demand aggregation and community generation schemes.

We are committed to continuing to develop innovative and effective ways of engaging with our customers and stakeholders, meeting our customers' changing needs as energy storage, distributed generation and other demand-side technologies continue to develop.

6.6. We have continued to focus on safety as our top priority

While we have been transforming our business, we have maintained our focus on the safety of the community, our employees and contractors as our highest priority. Over the current five year period, we have:

- Achieved a significant reduction in the number of incidents resulting in personal injuries. Our Lost Time Injury Frequency Rate (LTIFR) is tracking at 1.05 per annum which is below the overall national industry average of 4.5 per annum. We are moving towards measuring our safety performance based on lead indicators as we continue to build a strong safety culture within our business;
- Hosted, and provided support for, a research project at our Frankston South zone substation. This aims to gain a detailed understanding of the benefits of Rapid Earth Fault Current Limiters (REFCLs) in reducing the risk of bushfires in the rare occurrence that a bare overhead powerline conductor falls to the ground. The project was initiated on the recommendation of the Powerline Bushfire Safety Taskforce following the VBRC. The testing confirmed that when a live high voltage conductor falls to the ground, under worst-case fire weather conditions such as those experienced on Black Saturday 2009, the REFCL could reduce the conductor-soil arcing to levels below that required to start a fire. We plan to install more REFCLs at our zone substations in the forthcoming regulatory period to reduce the risk of bushfires from conductor failure;
- Accepted a request from the Victorian Government to assist with research into fire ignition and measurement of fault current and voltage disturbances that occur when overhead powerlines contact trees and branches. The research has been undertaken at our Springvale zone substation during 2015;
- Addressed our regulatory obligation imposed by Energy Safe Victoria (ESV) to ensure the safe provision of electricity to end consumers, where an effective neutral connection at each property is essential by undertaking a Neutral Supply Test (NST) on-site at each property:
  - Once every 10 years; and
  - Whenever there is a change to a physical meter configuration;

  in accordance with our Electricity Safety Management Scheme (ESMS) compliance.
- Developed a plan to implement an intelligent software solution utilising analytics on AMI meter data to detect neutral integrity issues as they occur. This will avoid site visits other than those where detected issues need investigation and rectification. Avoiding site visits for neutral integrity testing translates to a lower risk of electrical shocks due to associated neutral integrity issues. Our approach will ensure that neutral integrity tests are performed on a daily basis and are corrected before the customer notices any problems;
- Inspected our assets located in high bushfire risk areas on a three year cycle, and our assets located in low bushfire risk areas on a five year cycle, in accordance with our ESMS. The inspection, condition assessment, and refurbishment of our assets in accordance with our ESMS is nearing completion for the current regulatory period. All assets identified during these inspections as requiring attention have been attended to, or are subject to work that is programmed to be completed within six months of the need being identified;
- In accordance with our ESMS, we have:
  - Replaced low voltage services identified as being too low or defective;

- Removed public lighting switchwire;
- Replaced wooden cross arms;
- Replaced HV fuses, surge diverters, and insulators;
- Cleaned and tightened pole top structures;
- Installed aerial bundled cable in high bushfire risk areas;
- Replaced or staked wooden poles;
- Installed backup protection schemes;
- Replaced Doncaster-type LV service pillars;
- Replaced air break switches;
- Installed vibration dampers and armour rods in high bushfire risk areas; and
- Undertaken works on HV spans to prevent conductor clashing.

- Worked hard to deliver better bushfire safety outcomes by lowering bushfire risk across our network. The safety initiatives we have taken include our responses to the recommendations of the VBRC. While these initiatives have placed upward pressure on costs, they have delivered substantial benefits to our customers and the wider community. Our electricity network operations have not contributed to starting a bushfire for almost 10 years.

7. What our stakeholders are telling us

7.1. Key findings from our stakeholder engagement

During the current regulatory period we were focused principally on transforming our business model and ensuring that the planned efficiency improvements were achieved. As indicated in Chapter 5, our focus for the forthcoming regulatory period is to put customers at the centre of our business.

While there is a clear regulatory imperative for us to engage with our customers and stakeholders, we recognise that best practice engagement should be an integral and on-going part of our operating model. This requires a shift in culture, the introduction of new specialist skills and time to build understanding and trust with an extensive group of stakeholders who have an interest in our services. We have established a web page[6] to enable customers to provide feedback directly to us, and we encourage all stakeholders to talk to us on any matter of importance to them.

As a first step, we engaged KPMG to assist us in obtaining stakeholder input in developing our Regulatory Proposal. KPMG facilitated six focus groups, comprising 57 participants, and two workshops, one with our Customer Consultative Committee and another with our large and commercial consumers. KPMG also designed a Willingness to Pay (WTP) survey, in light of the priorities and service improvement suggestions identified in the focus groups and workshops.

The fundamental priorities for our customers are reliability, affordability and communication. The key findings from our customer research indicate that:

- Affordability is a key issue for our customers. This has been further highlighted by recent correspondence from the Energy and Water Ombudsman Victoria (EWOV) that we have provided as an attachment to our Regulatory Proposal;
- Customers do not want to accept lower reliability in exchange for lower prices;
- Customers perceive electricity to be a basic utility. Electricity supply should be constant and of high quality, and customers do not see any reason to pay a premium for improved reliability;
- Customers want better communication about planned and unplanned interruptions;
- Customers generally want better and more timely information and guidance to enable them to control their electricity consumption and bills;
- Customers are willing to respond to incentives to reduce their maximum demand, although this can be more difficult for business customers; and
- We are meeting customers' expectations regarding the day-to-day issues of vegetation management, safety and aesthetics.

The input from customers is important in formulating our expenditure plans. In particular, customers are clear that lower reliability would be unacceptable, even if it leads to lower electricity costs. By the same token, while reliability is highly valued, customers expect us to deliver this standard and do not want to pay more for increased reliability. Our customer feedback is consistent with the Rules' objective of 'maintaining reliability'.

We are also conscious of the need to provide customers with the tools to manage their demand in order to reduce their electricity bills.

[6] http://unitedenergy.engagementhq.com/creating-the-intelligent-utility

7.2. Our response to stakeholder feedback

Table 7-1 sets out key customer outcomes which form part of our Regulatory Proposal, matched against the findings of our engagement activities, categorised by general issue.

Table 7-1: Key customer outcomes

Issue	Customer objective	Outcome
Affordability and reliability	Customers do not want to pay more for better reliability or additional services.	We will maintain reliability and cut our charges for a typical customer by approximately $70 in 2016.
Better communication	Customers want better information faster, when the lights go out.	We will invest in ICT solutions to provide better outage information, online customer claims and tracking tools and a self-service portal for new connections to streamline the process for customers, electricians and developers.
Energy information	Customers want access to energy consumption data to help control electricity bills.	We will invest in our customer portal '*EnergyEasy*' to give customers ready access to the information they need to make informed energy choices.
Market transactions	Retailers want us to improve the quality and reliability of our market transactions and data provision, including the reliability of transfer reads and re-energisation / de-energisation transactions.	We will continue to invest in our ICT systems to improve the quality and reliability of market transactions. We will also take advantage of the remote capabilities of AMI meters for transfer and re-energisation / de-energisation reads.
Energy innovation	Councils and some customer groups want us to find alternatives to traditional network investment to meet growing peak demand.	We will continue to pursue non-network solutions including demand-side initiatives and technology.
Safety and environment	Councils want us to find better solutions to manage vegetation in order to balance our safety requirements with local amenity.	We are proposing $3 million for a three-year trial of dedicated vegetation management crews to work with local councils in our area.
Public lighting	Councils want to better manage the price/service offering for public lights.	The AER's Victorian Framework and Approach paper supported our proposal to split public lighting into two services: a regulated service applicable to services involving shared public lighting assets and a negotiated service which relates to dedicated public lighting assets. The negotiating framework is submitted with our Regulatory Proposal.

In the next section, we provide a more detailed explanation of what we will deliver in the forthcoming regulatory period in light of the feedback received from our customers.

8. What we will deliver

With our business transformation complete, we have identified the following priorities for the forthcoming regulatory period. We will:

- Deliver a price cut;
- Increase our focus on meeting customers' needs and expectations;
- Increase the value of the services we provide to our customers by investing in technology;
- Meet new Government-imposed regulatory obligations;
- Continue to focus on safety; and
- Invest in order to maintain network reliability.

These priorities are discussed in turn below.

8.1. Price cut

We are acutely aware that although we deliver superior outcomes in terms of cost and service performance, electricity affordability is a major issue for our customers. We will respond to this by delivering a price cut in 2016 of approximately $70 for a typical customer. We will keep real prices at this reduced level for the remainder of the forthcoming five year period.

8.2. Putting customers first

Our long-term corporate roadmap makes our customer focus a core theme. The roadmap guides us in everything we do, so it is a critical touchstone for us, and it reflects our clear intention to put customers first. As explained in the section below, we are working to increase the value of our services to customers by investing in technology.

As part of our commitment to putting customers first, we will also ensure that we meet the engagement expectations of our customers and stakeholders by investing in specialist skills and resources. This will ensure that we continue to build trust with our stakeholders and work with them to fully understand our customers' needs and preferences.

8.3. Increasing customer value through technology

In putting customers first, our goal is to deliver, as efficiently as possible, safe and reliable services that customers value highly. In the forthcoming regulatory period, our ICT capital investment will help enable us to achieve this goal.

We have already introduced the first phase of a major initiative to deliver what we call an *Effortless Customer Experience*. Under this initiative we will provide services that will:

- Assist customers to better understand their energy usage and choices; and
- Provide customers with the tools they need to make these choices in the future.

Specifically, we will focus on empowering customers by providing them with convenient access to information in relation to our network and their energy choices by:

- Providing more accurate and timely information on unplanned outages to assist customers' decisions about how to respond at home and at work, reducing the cost and inconvenience to customers of supply interruptions;
- Providing online customer claim facilities and tracking tools, increasing the ease and convenience to customers in making a claim;
- Enhancing our existing *Energy Easy* customer portal to allow customers to receive notifications and clear energy consumption data, and to maximise their benefits from AMI;

- Implementing a self-service New Connections portal for customers, electricians and developers to streamline the connections process, thereby saving time and reducing costs to them; and
- Introducing new cost reflective demand based tariffs that will reduce cross subsidies between customers, better signal the future costs of building and maintaining the network and give customers more choice about how they influence their energy bills.

We will also leverage the AMI rollout by delivering smarter solutions for our customers. For example, we are required by regulation to test earthing systems and electrical protection systems at each site every 10 years. This means visiting 65,000 customer sites annually. In the forthcoming regulatory period, we can eliminate the need for these routine site visits by implementing an intelligent software solution to detect neutral integrity issues remotely. This will deliver significant cost savings to our customers. It also delivers benefits in terms of enhanced safety, which remains our first priority, as discussed below.

8.4. Meeting new Government-imposed regulatory obligations

As a regulated business, we must comply with all obligations imposed by Government.

There are a number of regulatory changes that are either underway or are proposed by Government, for the forthcoming regulatory period. These regulatory changes will have both capex and opex impositions for our standard control services, and therefore price impacts, for our customers.

Table 8-1 details our forecast of the impact of the key new regulatory obligations.

Table 8-1: New Regulatory Obligations (Standard Control Services) for 2016 to 2020 ($M, Real 2015)

	Opex	Capex	Total
Power of choice	12.5	37.2	49.7
Regulatory reporting requirements	1.6	24.3	25.9
Energy Safe Victoria	9.7	0.0	9.7
Total Costs	**23.8**	**61.5**	**85.3**

The costs in Table 8-1 are all in addition to our 2014 base year costs.

We consider that the customer benefit of these regulatory changes has not necessarily been clearly demonstrated by Government. However, because they are regulatory obligations, we have not sought to identify the benefits in this Regulatory Proposal. Rather, we have simply sought to identify the cost of implementing the required changes.

We calculate that the cost of implementing these regulatory changes over the forthcoming regulatory period is approximately $110 per customer or an annual charge of $22 per customer per annum. This gives an indication of the additional price reductions that we could deliver to customers if these regulatory obligations did not apply in the forthcoming regulatory period.

We encourage our stakeholders to consider the value of these regulatory changes and to make submissions about them to both the AER and the Government.

8.5. Continued focus on safety

The safety of our customers, community, staff and contractors remains our primary focus. Section 6 provides an overview of the work we have undertaken in the current regulatory period to ensure a high standard of safety. Our expenditure plans build on that work. They address all of our compliance obligations and include a number of measures that are focused on safety improvements, particularly in relation to bushfire risk. Specifically:

- We will continue to strive to reduce our LTIFR, which is already tracking well below the national industry average;
- We will continue to develop programs to improve the safety of our network;
- We will continue to participate in and support research on the benefits of REFCLs in reducing the risk of bushfires, as well as research into fire ignition;
- We plan to install more REFCLs at our zone substations in the forthcoming period to reduce the risk of bushfires;
- We will continue to leverage AMI technology to undertake neutral integrity testing;
- We will undertake all work in accordance with our ESMS, Bushfire Mitigation Plan and Electric Line Clearance Plan;
- We will continue to work with our customers and local councils in our region to ensure that vegetation is kept clear of overhead power lines; and
- We will continue to work hard to lower the bushfire risk across our network, in accordance with the recommendations of the VBRC.

8.6. Meeting customers' needs for a reliable network

New technologies, such as solar PV, will continue to add to the complexity of energy supply, enhancing customer choice and environmental outcomes. However, we expect that the network will retain its primacy in the distribution of energy, leading to the integration of these new technologies rather than defection by customers. Our investment plans must ensure that the network continues to remain price competitive and provide the services our customers require whilst also facilitating the uptake of new technology.

As explained in Chapter 7, our customers want us to maintain reliability, which means arresting the trend of the deterioration in our network reliability performance. To ensure that we deliver maximum value to our customers, our network capital investment will focus on the lowest cost solutions, looking beyond the forthcoming regulatory period, by:

- Replacing assets at end of life with the objective of minimising total life cycle costs;
- Deferring capex through targeted refurbishment, condition monitoring and risk management initiatives;
- Improving reliability outcomes for those customers in our worst served areas; and
- Pursuing alternatives to traditional investment in network capacity to meet growth in peak demand where it is economic to do so.

Our capex program - described in further detail in Chapter 10 - reflects these specific actions, and will enable us to provide safe and reliable services that meet customers' needs whilst minimising the total lifecycle cost of service delivery.

9. Demand forecasts

Key messages:

- We forecast our underlying maximum demand to grow on average by 2.0 per cent per annum (10 per cent probability of exceedance (PoE)) over the forthcoming regulatory period, compared to 1.0 per cent per annum (10 per cent PoE) over the current regulatory period, predominantly driven by stabilising electricity prices and improved economic conditions.
- NIEIR has prepared our maximum demand "boundary load" forecast under base, high and low economic growth scenarios, and 10, 50 and 90 per cent PoE ambient temperature scenarios. NIEIR and ACIL Allen Consulting have developed a range of post-model adjustments for the effects of disruptive technologies, which we have applied to NIEIR's forecast.
- AECOM has developed an independent top-down macro-economic maximum demand forecasting model, which we have used to verify NIEIR's forecast. Their 10 per cent PoE forecasts match closely with NIEIR's. There are small differences between the AECOM and NIEIR's 50 and 90 per cent PoE forecasts however these relate to the initial launch point year of 2015 rather than the growth rates.
- We prepared a comprehensive bottom-up, "spatial" forecast of maximum demand at the zone substation level and upwards (including sub-transmission and transmission connection points) and at the high voltage distribution feeder level. We reconciled this to NIEIR's top-down "boundary load" maximum demand forecast.
- We have also reconciled our forecast to that prepared by Australian Energy Market Operator (AEMO) at the Victorian level and at the transmission connection asset level. The 2014-15 summer maximum demand forecasts ('launch points') reconcile closely and we explain the other differences between the forecasts in detail.
- We use the "spatial" maximum demand forecast to inform our Augmentation capex forecast and our "boundary load" forecast to inform our "rate of change – output" growth allowance in our opex forecast.
- As well as investing in our network, we will manage our growth in maximum demand by making greater use of maximum demand tariffs, investing in non-network alternatives and looking for expenditure deferral opportunities as we have done in the current period for Augmentation capex.
- We forecast our customer numbers to grow on average by 1.0 per cent per annum over the forthcoming regulatory period and our energy consumption to grow by an average of 0.4 per cent per annum.

This section explains and justifies our forecast maximum demand and customer numbers for Standard Control Services for the forthcoming regulatory period. It also details our forecast energy consumption for the period.

This section and our supporting documents address the requirements of the Rules and the RIN in relation to our forecast demand. Specifically, clauses 6.5.6(a)(1) and 6.5.7(a)(1) of the Rules require that our opex and capex forecasts "meet or manage the expected demand for standard control services". Clauses 6.5.6(c)(3) and 6.5.7(c)(3) require the AER to accept our opex and capex forecasts if they reasonably reflect a realistic expectation of the demand forecast required to achieve the opex and capex objectives. Clause S6.1.1(3) of the Rules requires us to detail "the forecasts of load growth relied upon to derive the capex forecasts and the method used for developing those forecasts of load growth". Section 8 of the Reset RIN requires us to provide certain information in relation to our demand forecasts.

9.1. Overview of forecasts for forthcoming regulatory period

Table 9-1 details our forecast demand for our forthcoming regulatory period under our base case scenario.

Table 9-1: Demand forecast – base case

	2016	2017	2018	2019	2020
PoE 10 Maximum Demand (MW)	2,169	2,229	2,296	2,375	2,374
PoE 50 Maximum Demand (MW)	1,945	1,984	2,052	2,102	2,123
Energy delivered (GWh)	7,585	7,600	7,672	7,726	7,776
Customer numbers	672,730	679,184	686,180	692,578	698,755

Table 9-2 details our forecast annual growth rates in demand for our forthcoming regulatory period under our base case scenario.

Table 9-2: Demand forecast – growth rates from previous year – base case (% pa)

	2016	2017	2018	2019	2020
PoE 10 Maximum Demand	0.3	2.8	3.0	3.4	0.0
PoE 50 Maximum Demand	0.2	2.0	3.4	2.4	1.0
Energy delivered	(0.5)	0.2	1.0	0.7	0.7
Customer numbers	1.0	1.0	1.1	1.0	1.0

We have used our forecasts of:

- Maximum demand to forecast our Augmentation capex and our "rate of change – output" growth allowance in our opex forecast; and
- Customer numbers to inform our Connections capex forecast and our "rate of change – output" growth allowance in our opex forecast.

In relation to our proposed tariffs, we also intend applying our:

- Maximum demand forecast as we move from tariffs based on consumption to tariffs that better reflect customers' use of the network at peak times; and
- Energy consumption forecast to the extent that we continue to base an element of our tariffs on customers' use.

We will detail these tariff arrangements in our Tariff Structures Statement that we will submit to the AER in September 2015.

9.2. Maximum demand

Maximum demand is the highest level of demand recorded within a given period. Our maximum demands occur during the summer season. For our "boundary load", our maximum demand is the maximum average demand over any half-hour period occurring between November and March inclusive as measured by NEM meters at the transmission connection points and the boundaries of our distribution network, plus any demand supplied by large-scale (>1 MW) embedded generators.

9.2.1. Maximum Demand Forecast

Our maximum demand typically occurs during periods of extreme high temperature conditions in summer on a working weekday. These weather events are difficult to predict in advance because of the variability of weather extremes. Consequently, maximum demand projections are often presented as a probability distribution of possible maximum demand levels; that is, in terms of weather-normalised PoE levels, usually at 10 per cent, 50 per cent and 90 per cent PoE representing one-in-ten, one-in-two and nine-in-ten year events.

We forecast underlying maximum demand to grow at 2.0 per cent per annum (10 per cent PoE) over the forthcoming regulatory period[7], compared to 1.0 per cent per annum (10 per cent PoE) over the current regulatory period. The relatively low growth in the current regulatory period was predominantly a result of slowing economic growth following the Global Financial Crisis and the end of government economic stimulus, coupled with rising retail electricity prices. Higher growth in the forthcoming regulatory period reflects maximum demand returning to levels observed in previous years as electricity price impacts stabilise, as shown in the table below.

Table 9-3: Demand forecast – growth rates – comparison of previous and current period to next period

PoE 10 Maximum Demand	2006-2010	2011-2015	2016-2020
Weather-Corrected Actual or Forecast (MW)	2,064	2,163	2,374
Growth (MW) over five years	186	99	211
Growth Rate (%pa)	2.0	1.0	2.0 [7]

The relationship between maximum demand growth, economic and population growth, and retail electricity price growth has been established through two independent 10-year models, namely NIEIR's PeakSim model and AECOM's eViews model. Disruptive technology generally has a downward influence on maximum demand, and these effects are modelled separately and applied as post-model adjustments. Our maximum demand forecasts include the effects of these post-model adjustments.

Table 9-4 presents our maximum demand "boundary load" forecasts at 90 per cent, 50 per cent and 10 per cent PoE levels for the next 10 years.

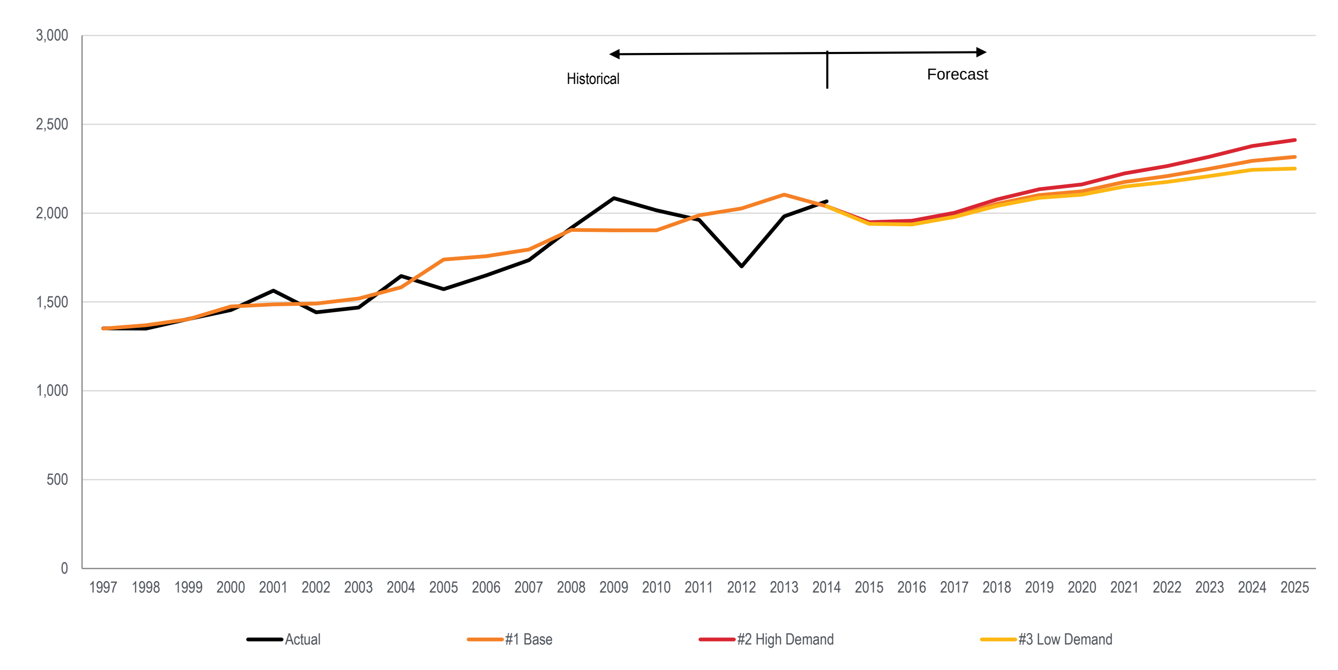
[7] Based on UE's Maximum Demand Overview Paper, the elasticity of UE's Maximum Demand "boundary load" to economic growth, population growth and retail price growth are 0.61, 0.94 and -0.11 respectively. Based on NIEIR's report titled "Energy, Demand and Customer Number forecasting for United Energy to 2025", with economic growth, population growth and retail price growth over the forthcoming regulatory period estimated at 1.7%pa, 1.2%pa and 0.0%pa (in real terms) and the impact of disruptive technology post-model adjustments at -0.2% pa, UE's Maximum Demand growth rate over the next period is estimated to be 0.61 x 1.7 + 0.94 x 1.2 – 0.11 x 0.0 – 0.2 = 2.0% pa.

Table 9-4: Maximum demand "boundary load" forecasts (MW)

Year	Actual	Weather-Corrected Actual / Forecast		
		90% POE	50% POE	10% POE
2006	1,649	1,613	1,758	1,903
2007	1,750	1,643	1,795	1,948
2008	1,918	1,749	1,906	2,062
2009	2,084	1,746	1,903	2,060
2010	2,016	1,743	1,904	2,064
2011	1,962	1,803	1,988	2,173
2012	1,700	1,868	2,027	2,185
2013	1,982	1,923	2,104	**2,284 (previous peak)**
2014	2,066	1,839	2,038	2,237
2015	n/a	1,756	1,942	2,163
2016	n/a	1,768	1,945	2,169
2017	n/a	1,778	1,984	2,229
2018	n/a	1,849	2,052	**2,296 (new peak)**
2019	n/a	1,887	2,102	2,375
2020	n/a	1,926	2,123	2,374
2021	n/a	1,967	2,176	2,432
2022	n/a	2,000	2,208	2,472
2023	n/a	2,025	2,249	2,548
2024	n/a	2,060	2,294	2,596

Figure 9-1 details our historical actual, weather corrected 50 per cent PoE actual and forecast 50 per cent PoE "boundary load". Three forecast scenarios are shown: low demand; high demand and base demand.

Figure 9-1 – Top-down 50 per cent PoE maximum demand "boundary load" forecast (with post-model adjustments) and historical actuals (MW)



9.2.2. Implications of demand forecast for Augmentation capex

Our forecast Augmentation capex is lower than our actual Augmentation capex for the current period for two main reasons:

- Firstly, between 2013 and 2016, our service-area weather-corrected maximum demand has declined and is expected to stagnate as shown in Table 9-4, predominantly because of the impact of substantial electricity price rises in recent years. This decline has a capital deferral impact contributing to a lower forecast Augmentation capex for the forthcoming regulatory period, even though maximum demand is expected to grow at a higher annual rate in the forthcoming regulatory period. This is because the network has essentially been built to support the 2012-13 10 per cent PoE weather-corrected maximum demand of 2,284 MW. This level of demand is not expected to be reached again until 2017-18, two years into the forthcoming regulatory period. This has resulted in the deferral of a number of major augmentation projects. Notwithstanding this, there is considerable variation in demand growth rates across our network. The "spatial" maximum demand forecast is used to assess localised network capacity constraints. These localised assessments inform our Augmentation capex. Given the variability of demand growth rates across the network, a lower "boundary load" maximum demand does not translate into zero Augmentation capex, rather a lower Augmentation capex; and
- Secondly, we have identified savings in our Augmentation capex with the incorporation of AMI (smart-meter) data into our network planning processes. This new data source allows us to provide a more targeted (and therefore more optimised) approach to addressing low-voltage network capacity constraints. Our historical expenditure in this area has been around $10 million per annum and is reducing. This is expected to fall to around $6 million per annum by the end of the forthcoming regulatory period as a result of AMI benefits realisation, a saving of around $10 million in total over the next period.

Further details of our Augmentation capex forecasts are provided in section 10.10.

9.2.3. Forecasting methodology

The method by which we develop our maximum demand forecasts is consistent with the approach adopted by AEMO and the approach recommended by ACIL Allen Consulting in its report to AEMO titled “A nationally consistent methodology for forecasting maximum electricity demand”, dated 26 June 2013.

We have developed our maximum demand forecast with the assistance of NIEIR, who are experts in the field of electricity demand forecasting. NIEIR has prepared our “boundary load” maximum demand forecast using top-down econometric methods. This “boundary load” forecast is used to reconcile our bottom-up “spatial” maximum demand forecasts, with the “spatial” forecasts used to derive the Augmentation capex forecast.

To provide forecasting transparency for the AER’s review, we have made available NIEIR’s maximum demand forecasting model (as well as the AECOM model used to independently validate the NIEIR forecast – see below).

NIEIR uses a forecasting model known as “PeakSim” to forecast our “boundary load” maximum demand. PeakSim takes into account the impact of many variables including temperature, time-of-year, economic conditions (including gross state product, population growth and dwelling stock), electricity prices and air-conditioning stock. In preparing the forecast, PeakSim segments maximum demand into two parts:

- Temperature insensitive demand - the part of demand that would occur irrespective of the weather conditions. This demand is strongly related to the estimated growth or decline in energy sales; and
- Temperature sensitive demand - the part of demand that occurs due to prevailing weather conditions. Changes in the penetration of temperature sensitive appliances such as air-conditioning and evaporative cooling equipment provide a proxy for the projections of this component of demand.

The probability distribution of maximum demands captures the impacts of different weather extremes and the general randomness of customer behaviour on maximum demand events. A simulation method called ‘bootstrapping’ is employed to generate the probability distributions in our maximum demand forecasts. This involves sampling historical temperature data and regressing residual estimates to generate a large number of synthetic sequences of temperature and the residuals. These synthetic sequences are then fed back into the estimated demand-temperature equations to generate synthetic sequences of demand.

The highest readings from each synthetic demand sequence are then identified. These readings represent feasible levels of maximum demand and form the basis of the maximum demand probability distribution. The 90th, 50th and 10th percentile values of the highest readings are the 10 per cent, 50 per cent and 90 per cent PoE levels, respectively. PoE levels are separately generated for each forecast year using the respective year’s projected demand-temperature equation.

The details of the NIEIR maximum demand forecast are contained in the document “Energy, Demand and Customer Number forecasting for United Energy to 2025 – Part A”, which we have provided with this Regulatory Proposal.

A number of potentially significant emerging developments are occurring, or are about to occur, in the way that customers use their electricity. These developments will ultimately have a measurable impact on our maximum demand growth (either positive or negative) and therefore our Augmentation capex. These disruptive technologies are treated as post-model adjustments to the maximum demand forecast prepared by PeakSim. These elements are modelled separately because of the lack of observed history of these technologies on past maximum demands, with the regression modelling unlikely to represent their future impact accurately.

The estimated impacts of solar PV, EV, energy efficiency (EE), storage and demand management at the time of maximum demand are used to derive the final maximum demand projections. The details of NIEIR’s assessment and findings are available in the document “Energy, Demand and Customer Number forecasting for United Energy to 2025 – Part B”, which we have also provided with this Regulatory Proposal.

In order to gain further confidence in the forecasting of these post-model adjustments by NIEIR, we engaged ACIL Allen Consulting to perform a similar assessment of PV, EV and EE contributions to the maximum demand projections. ACIL Allen Consulting also assessed the impact on maximum demand of demand-based tariffs that we intend to propose as part of the Tariff Structure Statement. The findings of ACIL Allen’s study complement NIEIR’s assessment and allow us to consider high, low and base scenarios in our maximum demand forecasts.

Table 9-5 summarises the variables and basis for these scenarios.

Table 9-5 – Post model adjustment scenarios

Scenario	Solar PV	EV	Storage	Demand-Side	Efficiency
Base Maximum Demand Forecast	Average of reconciled NIEIR and ACIL Allen	NIEIR Base	DMIS[1] + planned economic installations only	DMIS + Tariff	VEET[2], MEPS[3], LED[4]
Low Maximum Demand Forecast	ACIL Allen	ACIL Allen (NIEIR Low)	DMIS + planned economic installations only	DMIS + Tariff + Non-network	VEET, MEPS, LED
High Maximum Demand Forecast	Reconciled NIEIR	NIEIR High	Zero	Zero	VEET only

[1] Demand Management Incentive Scheme

[2] Victorian Energy Efficiency Target

[3] Minimum Energy Performance Standards

[4] Light Emitting Diode (energy efficient lighting technology)

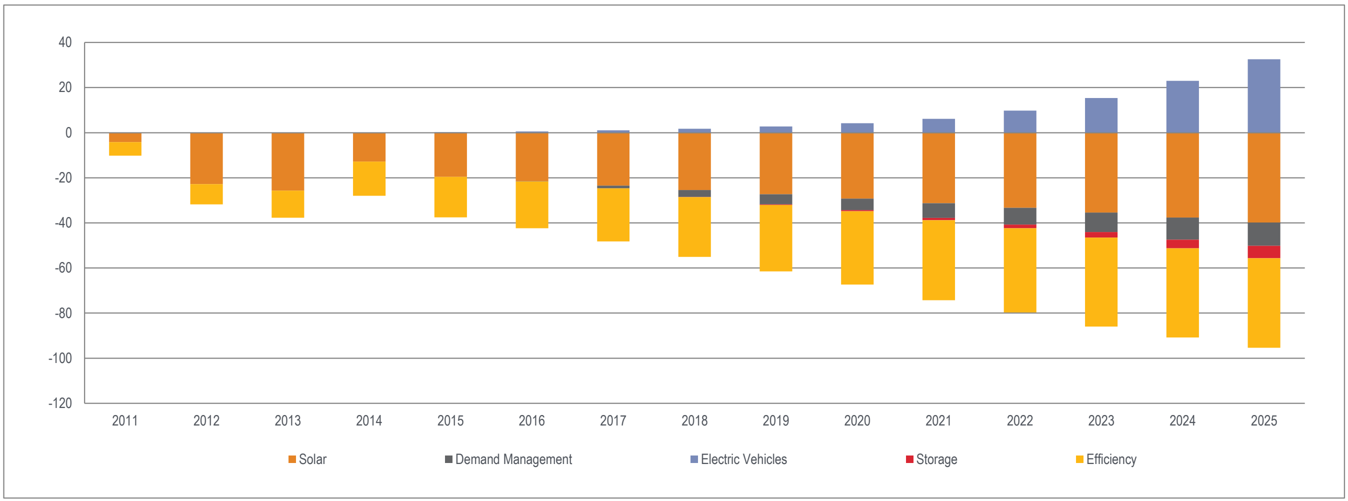
[5] Includes the impact of flexible demand tariffs

These base, low and high demand scenarios are detailed in our supporting document titled "Demand Strategy & Plan" (UE PL 2200) and drive the maximum demand scenario outcomes shown in Table 9-1. The details of the ACIL Allen Consulting study are available in the "Electricity Consumption Forecasts – Post Model Adjustments" Part B document.

Under all scenarios, the impact of disruptive technologies on our maximum demand is likely to be insufficient to affect our maximum demand growth driven Augmentation capex requirements over the forthcoming regulatory period.

We forecast our Augmentation capex using the "base" (most likely) scenario and combinations of the above post-model adjustments. The models developed by NIEIR and ACIL Allen Consulting are provided with our Regulatory Proposal to enable the AER to test the post-model adjustment forecast sensitivity to various input parameters.

Figure 9-2: Post-model adjustments included in UE's "boundary load" maximum demand forecast (MW)



While solar PV reduces our "boundary load" maximum demand by about one per cent, it should be noted that the vast majority of solar PV in our network is installed in residential areas. The timing of the residential maximum demand is approximately one hour later than the UE "boundary load" maximum demand. In effect the contribution of the solar PV in reducing the residential maximum demand is only around 0.5 per cent based on current solar PV penetration levels.

9.2.4. Forecast verification

We apply multiple levels of verification to the maximum demand forecast prepared by NIEIR, including a top-down verification using AECOM's "eViews" forecasts and a bottom-up verification using our own "spatial" zone substation forecasts.

Top-down verification

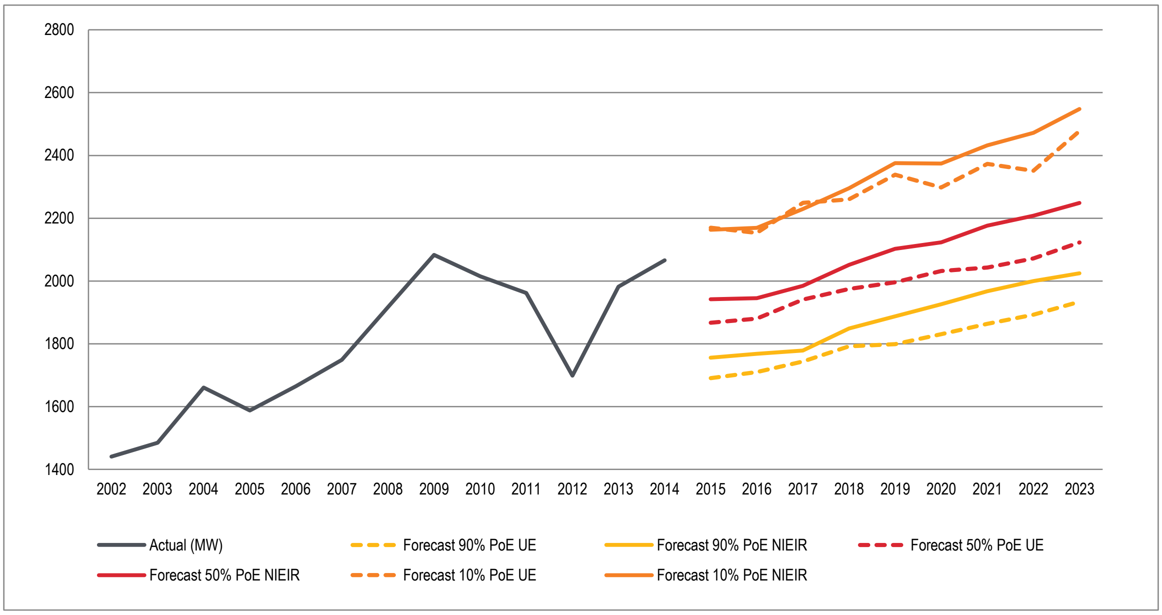
AECOM has developed an independent top-down macro-economic maximum demand forecasting model for our service area using the eViews software package. We use the eViews model to calculate a 10-year "boundary load" maximum demand forecast for 10 per cent, 50 per cent and 90 per cent PoE to compare and reconcile against the equivalent NIEIR forecasts. We have provided this eViews model to the AER with our Regulatory Proposal.

The eViews model is a simplified but independent version of NIEIR's PeakSim and follows the approach adopted by AEMO. It is a regression-based method and considers temperature, calendar and economic effects (such as gross state product, population, electricity prices and ownership of air conditioners) and solar PV generation.

The eViews model is combined with the simulation of synthetic temperature variables and random regression errors to produce maximum demand forecasts with different PoE using Monte-Carlo simulation.

Figure 9-3 compares our historical actual demands, NIEIR's forecast and our application of AECOM's eViews model forecast. It indicates that the 10 per cent PoE forecasts of both NIEIR and AECOM models match closely – they are within two per cent of each other between 2016 and 2020. There is a larger discrepancy in the forecasts for the milder temperature conditions of 50 per cent and 90 per cent PoE, however the difference is relatively constant year-on-year with virtually identical growth rates, indicating that there is some uncertainty in the initial launch point of 2015[8].

Figure 9-3: Comparison of historical demand, NIEIR forecast and AECOM forecast prepared for UE (MW)



It is important to note that the eViews model estimates demand based on existing trends (10 years of historical data) and relationships only. For example, the model considers the impact of solar generation and energy efficiency,

8 This uncertainty is reconciled against AEMO's launch point later in our Maximum Demand Overview Paper accompanying this Regulatory Proposal. We have also checked 2014-15 summer actuals against NIEIR's forecast for 2015. Based on this comparison, the NIEIR launch points have been confirmed as being accurate.

but only insofar as those are reflected in the existing trends, which are correlated with the explanatory data used. Faster or slower growth in solar generation or energy efficiency programs, which could result from policy changes, are not included and are better described by the NIEIR and ACIL Allen Consulting models provided. Therefore, the results from the eViews model are not expected to match the NIEIR maximum demand projections exactly, which are based on the more sophisticated PeakSim model combined with post-model adjustments of the disruptive technologies. Given recent observed slowdowns in the uptake of solar PV within our service area, the eViews model is likely to overestimate the impact of solar PV. Nevertheless, the eViews model provides a general independent view of the future maximum demand trends that confirm the validity of the forecasts provided by NIEIR.

Bottom-up verification

Each year we prepare a bottom-up forecast of maximum demand at two levels:

- Zone substation level and upwards (including sub-transmission and transmission connection point); and
- High voltage distribution feeder level.

After every summer, actual maximum demands at individual zone substations are extracted and weather-corrected. Based on the zone substation weather-corrected actual demands and anticipated localised growth, we prepare demand forecasts at individual zone substations. These zone substation forecasts are aggregated to the total level based on the relevant diversity factors while adjusting for sub-transmission losses to derive the bottom-up "boundary load". This diversified bottom-up forecast is then compared against our top-down "boundary load" maximum demand forecast prepared by NIEIR that has been reconciled with AECOM's top-down eViews model.

If any difference exists in our top-down and bottom-up "boundary load" forecasts, the bottom-up forecast is scaled to match with our top-down total forecast, along with all underlying forecasts, provided the difference is small. In the rare cases where the difference is significant, we discuss the variation with NIEIR in order to identify the reason for the discrepancy and then adjust the appropriate forecast accordingly. AECOM's top-down eViews model can help to identify any discrepancy. This process provides the reconciled demand forecast at zone substation levels. The reconciled zone substation forecasts are aggregated to the terminal station level based on the relevant diversity factors while adjusting for sub-transmission losses to prepare the transmission connection asset forecast for the Terminal Station Demand Forecast (TSDF).

Unlike zone substation actual maximum demands, high-voltage feeder actuals are not weather-corrected in the forecasting process. Instead, the 10 per cent PoE feeder forecasts are derived based on the weather-corrected zone substation growth rates. It is therefore presumed that the temperature sensitivity of all the feeders is similar to the temperature sensitivity of the zone substation to which those feeders are connected. However, the growth rates of individual feeders may be adjusted based on the local information where available (such as new connections).

We compare NIEIR's 10 per cent PoE top-down maximum demand forecast against our own aggregated, diversified 10 per cent PoE bottom-up zone substation forecasts, taking into account sub-transmission losses. The two forecasts closely align giving a maximum error of 2.3 per cent between the two forecasting methods throughout the 10-year forecasting period.

Figure 9-4 presents the relative percentage error between these two independently developed forecasts at each year within the forecasting period.

Figure 9-4: Comparison of top-down "boundary load" forecast with aggregated, diversified bottom-up 'spatial' forecasts

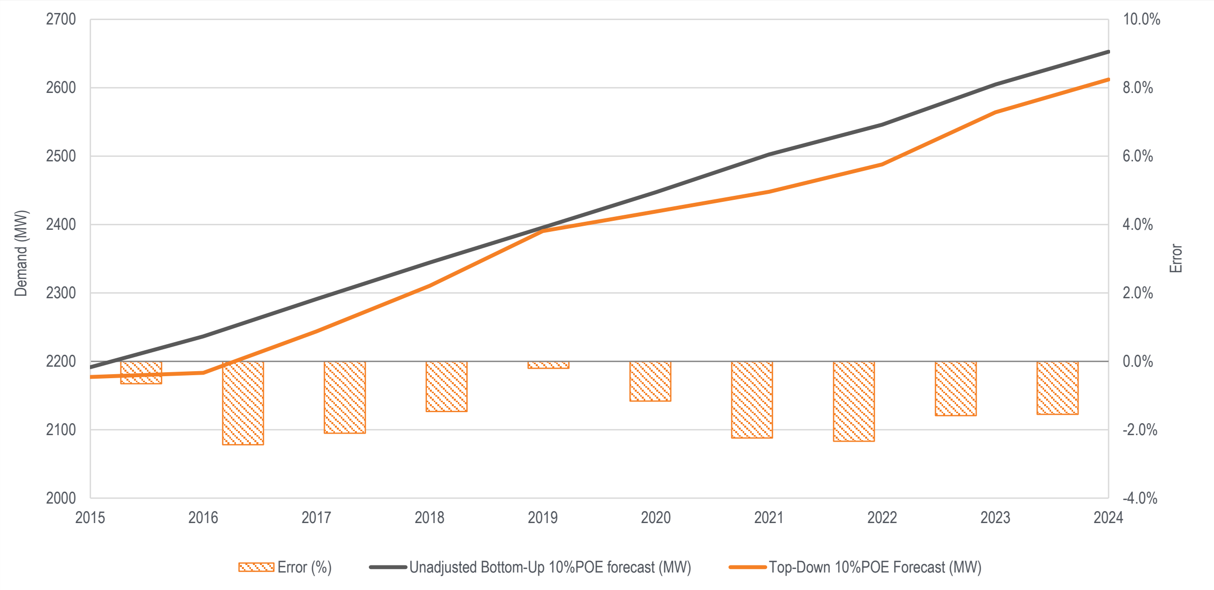


Figure 9-4 shows that the bottom-up forecast is marginally higher than the top-down forecast within the forecasting period. While the difference between the two forecasts is small, this apparent over-estimation bias can be explained by two-factors:

- Firstly, the raw bottom-up forecast does not take into account the post-model adjustments for any additional impacts from solar generation or energy efficiency that are not implicitly covered in the historical base data. This is because the post-model adjustments are forecast for the whole service area and not at the spatial level.
- Secondly, while we are informed of all new large load increases from industrial and commercial customers, we are not always informed of such customers reducing their demand.

Both of these factors contribute to the apparent bias, but we address this issue by scaling the bottom-up "spatial" forecasts to match the top-down "boundary load" forecasts to drive the final projections at the zone substation level for determining our Augmentation capex. This reconciliation process enables us to prepare a robust demand forecast at our overall "boundary load" level, and at each of the spatial levels including transmission connection points, sub-transmission system, zone substations and high voltage distribution feeders.

Further verification

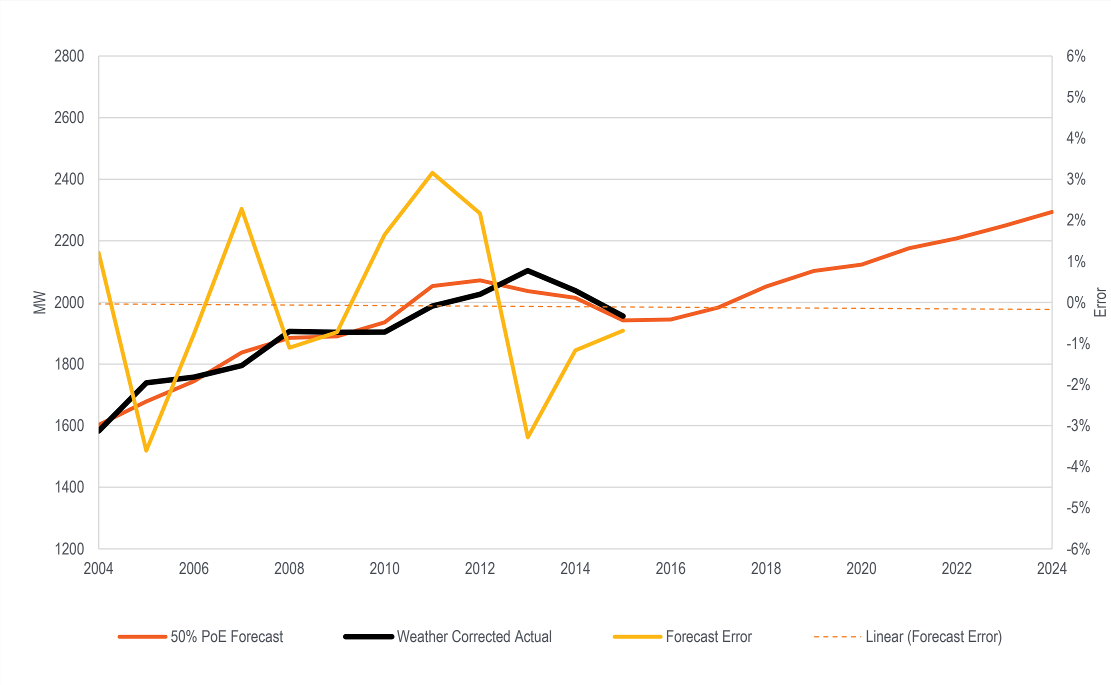
Several further verifications are undertaken to support our maximum demand forecasts.

NIEIR annually undertakes a back-casting exercise of its PeakSim model to test how well its predictions matched the actual observed maximum demands. This is described in NIEIR's "Energy, Demand and Customer Number Forecasting for United Energy to 2025 – Part A" report.

We also undertake further assessments each year to confirm the accuracy of NIEIR's PeakSim modelling for the most recent summer. Our most recent assessment indicates that the average error in the next year's 50 per cent PoE projections for the last 11 summers is -0.3 per cent. Similarly, the average error in 10 per cent PoE projections is 0.1 per cent. This demonstrates that, overall, the NIEIR model has a very good forecasting history and does not show any bias in under-forecasting or over-forecasting the maximum demand.

Figure 9-5 presents this information.

Figure 9-5: Weather corrected actual and forecast summer maximum demand comparisons



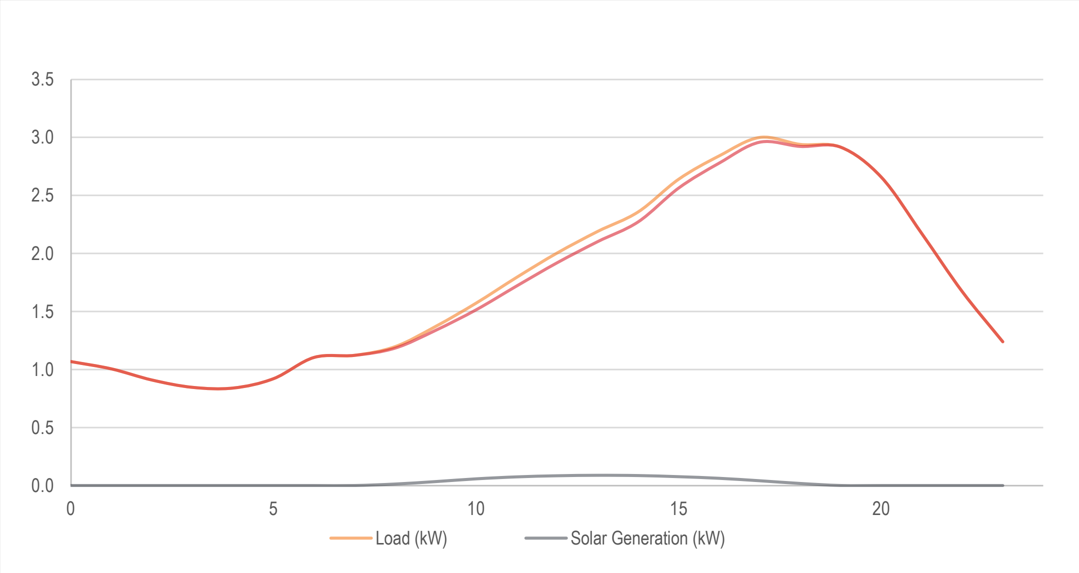
9.2.5. Reconciliation against AEMO's maximum demand forecasts

AEMO, as the transmission planning authority in Victoria, prepares an annual maximum demand forecast for Victoria, which it publishes in its National Electricity Forecasting Report (NEFR). In addition, AEMO has prepared and published a connection point maximum demand forecast (at terminal stations) for the Victorian DNSPs based on its forecast for Victoria in the NEFR. Given that this is the first time that AEMO has prepared connection point forecasts, the accuracy of AEMO's forecasts remains untested. We believe that AEMO's forecasts should be treated cautiously given the inaccuracy of their past forecasts.

To verify our maximum demand forecasts, we have reconciled our forecasts with AEMO's Victorian and connection point maximum demand forecasts. In summary, the reconciliation indicates that:

- Our, and AEMO's, 2014-15 summer maximum demand forecasts ('launch points') reconcile closely;
- Our, and AEMO's, 10-year underlying growth-rates (prior to applying the disruptive technology post-model adjustments) do not reconcile well. In our view, AEMO has understated the macro-economic factors (economic growth, population growth and retail price growth) that influence growth in maximum demand;
- Solar PV post-model adjustments forecast by AEMO at times of maximum demand appear overstated given that there is evidence of a slowdown in the uptake of solar PV installed in our service area over the last year and that solar PV contributions at the time of our peaks are very small. As previously explained, this is due to the time of day offset between maximum solar PV output and maximum consumer loads. The maximum output from solar PV is around midday when solar radiation is highest, whereas the maximum consumer load is in the early evening during summer, when people are home after work, and the rate of electricity consumption is highest with air conditioners and other appliances being used simultaneously. This is illustrated in Figure 9-6 below.

Figure 9-6: Impact of Residential Solar PV on Residential Maximum Demand at Present Solar PV Penetration Levels



- The energy efficiency post-model adjustment forecast by AEMO at times of maximum demand appears overstated given that actual building energy efficiency compliance is poor as reported by CSIRO[9]; and
- The EV post-model adjustment is not forecast by AEMO at all over the 10-year period despite the fact that plug-in EVs are being sold each year in Australia, and the total number of such vehicles is growing.

In our opinion AEMO's demand forecasts overstate the impact of disruptive technologies such as solar PV and understate the impact of recent electricity price rises (which are expected to moderate in the future) and economic growth. We provide further detailed explanation and evidence regarding the reconciliation of our forecasts to AEMO's forecasts in our "Maximum Demand Overview Paper".

9.2.6. Summary

Our maximum demand forecast which underpins our Augmentation capex forecast is robust. Based on the discussion presented above and the detailed analysis contained within our "Maximum Demand Overview Paper" and the other supporting documentation we have provided, our maximum demand forecasts are compelling for the following reasons:

- The methodology we apply to maximum demand forecasting is robust, best practice and consistent with the forecasting approach used by AEMO;
- We validate our maximum demand forecast by reconciling the NIEIR model with an independent top-down model developed by AECOM;
- Unlike AEMO, we validate our top-down forecast against our bottom-up "spatial" forecasts;
- We have incorporated the effects of disruptive technologies and changes in customer behaviour in our post-model adjustments;
- The long-term accuracy of the historical NIEIR forecasts has been demonstrated through weather-correction and back-casting;
- We have demonstrated that there is no long-term bias in the forecasting (i.e. no consistent over-estimating of maximum demand);

[9] CSIRO: http://www.industry.gov.au/Energy/Documents/Evaluation5StarEnergyEfficiencyStandardResidentialBuildings.pdf

- We have reconciled our maximum demand forecast against AEMO's Victorian and connection point forecasts and have provided detailed credible reasons to explain any variances;
- We have provided open-book access to our forecasting models and documentation; and
- We have provided the values of our regression coefficients which not only have a mathematically good-fit, but have values that are physically meaningful and reconcilable with reality.

The reconciliation results presented in our "Maximum Demand Overview Paper" demonstrate why our maximum demand forecasts are better supported and more appropriate for Augmentation planning on our distribution network than those provided by AEMO.

9.3. Customer numbers

We have forecast the number of customers that we will service in the forthcoming regulatory period.

9.3.1. Customer numbers forecast

Table 9-6 details our forecast customer number growth rates for the forthcoming regulatory period by customer category. Customer numbers are forecast to grow on average by 1.0 per cent per annum over the period.

Table 9-6: Customer numbers – growth rates – base case (per cent per annum)

	2016	2017	2018	2019	2020	Average
Residential	1.1	1.0	1.1	1.0	0.9	1.0
Business	0.6	1.3	1.7	1.6	1.5	1.3
Public lighting	(1.9)	0.8	0.6	1.4	1.0	0.4
Total	1.0	1.0	1.1	1.0	1.0	1.0

9.3.2. Forecasting methodology

Our customer number forecast has been prepared by NIEIR.

Residential customer number forecasts are driven by dwelling stock forecasts. Dwelling stock forecasts are an output from NIEIR's detailed construction industry models. The model covers residential approvals, commencements, completions and the building stock by type of dwelling. State forecasts of the dwelling stock are disaggregated into Local Government Area forecasts for our service area.

Non-residential customer number forecasts are a derivative of the historical growth in energy consumption, historical customer growth and average usage by class or network tariff.

The details of NIEIR's forecast are set out in the document "Energy, Demand and Customer Number forecasting for United Energy to 2025". We have provided this report, together with the associated model, to the AER with this Regulatory Proposal.

9.4. Energy consumption

Energy consumption is the sale of energy to customers measured in GWh over a period of time.

Table 9-7 details our forecast annual growth rates in energy consumption for the forthcoming regulatory period by customer category. Energy consumption is forecast to grow by an average of 0.4 per cent per annum over the period.

Our forecast has been prepared by NIEIR. The details of NIEIR's forecast are set out in the document "Energy, Demand and Customer Number forecasting for United Energy to 2025", which we have provided to the AER, together with the associated model, with our Regulatory Proposal.

Table 9-7: Energy consumption – growth rates – base case (per cent per annum)

	2016	2017	2018	2019	2020	Average
Residential	(0.3)	0.3	1.4	1.1	1.1	0.7
Commercial	0.6	1.1	1.4	1.4	1.4	1.2
Industrial	(2.7)	(1.5)	(0.6)	(1.3)	(1.4)	(1.5)
Business	(0.6)	0.1	0.7	0.4	0.4	0.2
Public lighting	(2.0)	1.0	1.0	1.0	1.0	0.4
Total	(0.5)	0.2	1.0	0.7	0.7	0.4

We apply our energy consumption forecast in developing our tariffs.

In the current period, around 75 per cent of our DUOS revenue is derived from energy (GWh).

In the future, we intend that an increasing proportion of our tariffs will be based on capacity and maximum demand in order that these tariffs better reflect customers' use of our network.

Nevertheless, a portion of our tariffs will continue to be based on customers' energy consumption. We will therefore continue to rely on our energy consumption forecast for this purpose.

We will detail our tariff arrangements in our Tariff Structures Statement that we will submit to the AER in September 2015.

10. Capex forecasts

Key messages:

- We benchmark favourably against our peers. The AER's benchmarking shows that we have the lowest asset cost per customer of any DNSP in the NEM. We have the highest utilised network in Australia. The benchmarking demonstrates that our new business model is efficient. Our customers are benefiting from this through lower network prices.
- Our capex in the current regulatory period supports the credibility of our forecasts. In the current period, we expect to spend about $33.5 million (or about 3.3 per cent more than the AER's allowance).
- Our capex delivery is prudent and efficient because:
  - Our governance arrangements ensure that we optimise investment decisions, informed by a well-developed asset management framework having regard to opex-capex substitution opportunities; and
  - Our contractual arrangements with our key service providers facilitate efficient delivery.
- Customers have said that they want us to maintain reliability performance, consistent with our regulatory obligations. However, our network performance is exhibiting a trend deterioration as a growing percentage of our assets have less than 15 per cent of their expected life remaining, resulting in increased asset failures.
- To address this performance gap and satisfy our compliance obligations, our total capex in the forthcoming regulatory period will increase by approximately $152 million ($ real 2015) or 15 per cent against our actual capex in the current regulatory period. We have minimised this increase by adopting a prudent, holistic approach to bridging the performance gap in our network reliability. This approach involves the targeting of Replacement, Augmentation and ICT capex in combination, to deliver our reliability target efficiently.
- We will arrest the current trend of deteriorating reliability by:
  - Delivering targeted network performance capex;
  - Improving inspection practices to facilitate better targeting of replacement capex;
  - Implementing operational technology initiatives that will improve our ability to identify and respond more rapidly to faults; and
  - Implementing improvements in our asset management system (AMS), to facilitate better asset management decisions that enable better targeting of replacement capex.
- We have validated our Replacement and Augmentation capex by applying the AER's Repex and Augex models. Our forecasts fall below the modelled outcomes.
- After successfully delivering our 2011 to 2015 ICT foundation capital program, we will continue to invest in ICT, which is integral to our operations. This investment will:
  - Deliver enhanced capabilities to meet customer needs and expectations;
  - Deliver smarter network technologies to ensure ongoing performance, resilience and safety in the changing distribution network;
  - Enable us to meet our new obligations from the AEMC's "Power of Choice Review" and the AER's RIN reporting requirements; and
  - Enable us to continue to maintain those systems that were implemented or modified under the Victorian Government's AMI CROIC and that are required for the on-going provision of Standard Control Services.

  Our Power of Choice and RIN reporting obligations contribute $61.5 million to our proposed ICT capex.
- Our forecast capex complies with the expenditure objectives and criteria in the Rules. It is supported by detailed asset and non-asset class strategies.

10.1. Introduction

Our capex forecasts must comply with the expenditure objectives and criteria set out in the Rules. In broad terms, the objectives require us to deliver safe, reliable and compliant services. We must achieve these objectives efficiently and prudently. Clause 6.5.7(a) of the Rules requires us to submit a capex forecast that is consistent with our regulatory obligations in relation to the quality, reliability and safety of the network and network services, or otherwise to maintain reliability and safety.

The Victorian Electricity Distribution Code[10] requires us to meet our customers' reasonable expectations of supply reliability. As noted in section 7.1, our customers have told us that lower reliability would be unacceptable, even if it leads to lower electricity costs. By the same token, while reliability is highly valued, customers expect us to maintain current reliability levels and do not want to pay more for improved reliability. In accordance with our regulatory obligation to meet our customers' reasonable expectations, our capex proposal aims to maintain current levels of reliability.

The Rules require us to provide the AER with early notification of our forecasting methodology for capex, which we submitted in May 2014. In that methodology, we explained that our capex forecasts are underpinned by a robust asset management framework and capex governance arrangements. For example, prior to seeking Board approval, our 'bottom up' forecasts are subject to critical internal review by our Electricity Network Management, which is responsible for:

- Evaluating, reviewing and prioritising the proposed investments (projects and works programs) across capex categories; and
- Reviewing the total capex forecast to ensure investment synergies and capex and opex trade-offs have been fully considered.

The governance process provides a 'top down' discipline on capex forecasts that are developed at a category level. The AER's capex categories are:

- Augmentation;
- Connections;
- Replacement; and
- Non-network.

In broad terms, our forecasting methodology is tailored to address the particular characteristics and expenditure drivers for each capex category and its component elements. In this Regulatory Proposal, we have applied the methodologies previously described in our submission to the AER. It is therefore not necessary to repeat the detailed description of these methodologies in this chapter. Instead, our focus is to explain the proposed capex amounts that have been derived from these methodologies.

The remainder of this chapter is structured as follows:

- Section 10.2 provides an overview of our capex forecast, and explains our prudent, holistic approach to satisfying our customers' expectations and regulatory obligation to maintain network reliability;
- Section 10.3 details how our business transformation supports our prudent and efficient capex;
- Section 10.4 explains how our expenditure governance framework supports the prudence and efficiency of our capex;
- Section 10.5 provides an overview of our asset management framework;
- Section 10.6 explains how we have derived our unit rates for our capex forecasts;
- Section 10.7 explains how we have applied cost escalators to our capex;

[10] Clause 5.2.

- Section 10.8 explains how recent benchmarking supports the efficiency of our capex;
- Section 10.9 explains our use of the VCR in our capex forecasts;
- Section 10.10 sets out our forecast Augmentation capex;
- Section 10.11 sets out our forecast Connections capex;
- Section 10.12 sets out our Replacement capex forecast;
- Section 10.13 sets out our Non-Network ICT capex forecast; and
- Section 10.14 sets out our Non-Network General capex forecast.

The capex forecasts presented in this chapter include only capital expenditure that is properly allocated to standard control services in accordance with the principles and policies set out in our Cost Allocation Method.

The information presented in this chapter is intentionally ‘high level’ to enable the AER, our customers and other stakeholders to understand the key drivers for our capex forecasts and the principal causes of any proposed increases in expenditure at the category level. It should be read in conjunction with our capex sub-category “Overview Papers” and other supporting documents that are provided as attachments to this Regulatory Proposal. These documents provide further information demonstrating that the proposed capex for each category satisfies the expenditure objectives and criteria in the Rules.

10.2. Capex forecast overview

10.2.1. Our forecast and historical capex

Our capex forecasts for each year of the forthcoming regulatory period are shown in Table 10-1.

Table 10-1: Forecast capex 2016-2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
SYSTEM ASSETS						
Augmentations	34.7	32.3	37.8	36.9	24.9	166.5
Connections	48.2	49.3	50.6	50.1	50.9	249.1
Replacement	118.9	125.6	124.8	113.8	101.9	585.1
Sub-total system assets	**201.8**	**207.2**	**213.2**	**200.8**	**177.7**	**1,000.7**
NON-NETWORK ASSETS						
Non-Network General Assets – ICT	30.7	44.9	37.0	21.7	29.3	163.7
Non-Network General Assets – Other	14.0	4.0	3.5	4.3	5.1	30.9
Sub-total non-network assets	**44.7**	**48.9**	**40.5**	**26.0**	**34.4**	**194.6**
Total capex	**246.5**	**256.2**	**253.8**	**226.8**	**212.1**	**1,195.3**
Less customer contributions	17.7	18.1	18.3	18.7	18.5	91.4
Net capex	**228.8**	**238.1**	**235.5**	**208.1**	**193.5**	**1,103.9**

We understand that the credibility of our capex forecasts depends, in part, on our performance record. In particular, customers want to understand how our capex forecasts compare with our actual capex during the current period. This comparison, together with our forecasting record, is one of the factors that the AER must consider in assessing whether to accept our capex forecasts (clause 6.5.7(e)(5) of the Rules).

Figure 10-1 shows our actual capex compared to the AER's allowance and our forecast capex for the forthcoming regulatory period.

Figure 10-1: Historical and forecast capex ($M, Real 2015)

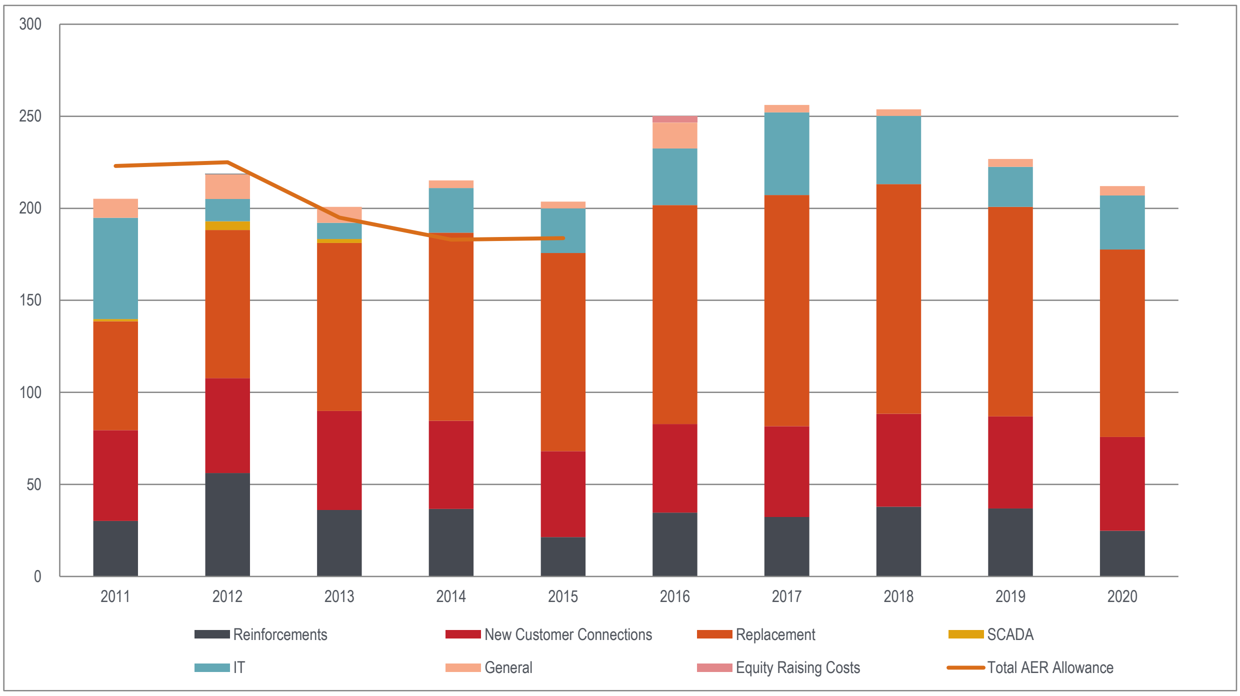


Table 10-2 shows that we expect our total gross capex during the current regulatory period to exceed the AER's allowance by $33.5 million or approximately 3.3 per cent. As customer contributions were lower than expected, the amount by which our capex exceeded the AER's allowance grew to $113.8 million on a net capex basis.

Table 10-2: Actual and allowed capex 2011-2015 ($M, Real 2015)

	2011	2012	2013	2014	2015	Total
Gross capex						
Distribution Determination	223.0	225.0	195.0	183.0	183.8	1,009.9
Actual / Estimates	205.1	218.8	200.8	215.1	203.6	1,043.4
Variance (Actual – Determination)	(17.9)	(6.2)	5.7	32.1	19.8	33.5
Net capex						
Distribution Determination	191.6	194.4	165.0	152.7	154.3	857.9
Actual / Estimated	189.0	199.5	185.2	206.7	191.3	971.8
Variance (Actual – Determination)	(2.6)	5.2	20.2	54.0	37.0	113.9

As a privately owned DNSP, we are strongly incentivised to remain within the AER's capex allowance. Despite this incentive, we expect that the AER's capex allowance will be insufficient in the current regulatory period. We will fund the overspend ourselves in this period. Our forecast capex for the forthcoming regulatory period should be assessed in light of this outcome.

As already noted, our total forecast capex for the forthcoming regulatory period is $1,195.3 million, which is approximately $152 million or 15 per cent above our capex for the current period. In the next section, we summarise:

- The key drivers for the increased capex in the forthcoming regulatory period;
- Our prudent, holistic approach to maintaining network reliability;
- The reasons why our forecast capex should be accepted by the AER with reference to the Rules' requirements; and
- The key assumptions that underpin our capex forecasts.

Further detailed explanatory information is provided in the subsequent sections of this chapter and in the relevant capex sub-category Overview Papers and other supporting documents.

10.2.2. Key drivers for increased capex

The Rules require us to submit a total capex forecast that will achieve the following objectives:

- Meet or manage the expected demand for our services;
- Comply with our regulatory objectives;
- Maintain network reliability; and
- Maintain the safety of our distribution network.

Our expenditure plans are focused on delivering these objectives at minimum total life cycle cost. At the outset, it is important to emphasise our commitment to safety. In the forthcoming regulatory period, we will continue to undertake bushfire mitigation measures, including SWER replacement, in accordance with our regulatory obligations. Through activities such as the Doncaster Pillars Replacement Program, we will also continue to address risks to the general public from electric shocks.

In terms of performance outcomes for customers, maintaining reliability is the most significant expenditure driver in the forthcoming regulatory period. As shown in Figure 10-2 and Table 10-3 below, our current network reliability is following a deteriorating trend. This is an important consideration given:

- Our regulatory obligation to 'maintain reliability'; and
- Customers' expectations that we should maintain supply reliability.

Figure 10-2: Actual and trend unplanned SAIDI

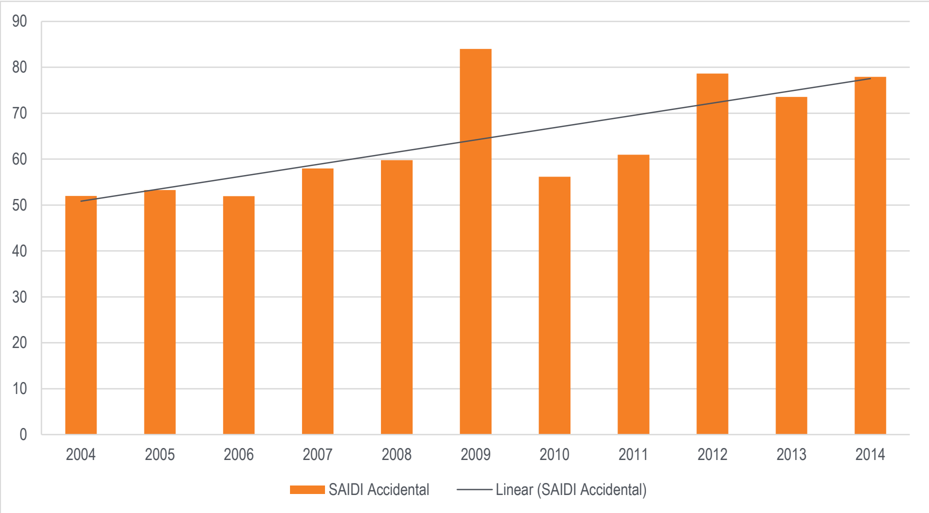


Table 10-3: Reliability performance 2006-2014

	2006	2007	2008	2009	2010	2011	2012	2013	2014
SAIDI unplanned[11]	52	58	60	84	58	61	79	74	78
SAIFI	0.94	1.01	1	1.23	0.95	0.96	1.11	1.01	1.02
MAIFI	1.17	1.09	1.17	1.18	0.98	1.08	1.17	1.31	1.13

In our Regulatory Proposal for the current regulatory period, we explained that our network performance was expected to deteriorate as a consequence of our ageing asset base. This expectation has come to fruition despite the strong commercial incentive we face under the AER's STPIS scheme to improve reliability.

Figure 10-3 highlights that the deteriorating trend in reliability is predominately driven by the age profile of our assets. As assets enter the later stages of their lives, the probability of equipment failure increases significantly.

[11] All metric based on the current MED exemption regime

Figure 10-3: Trend of assets approaching end-of life

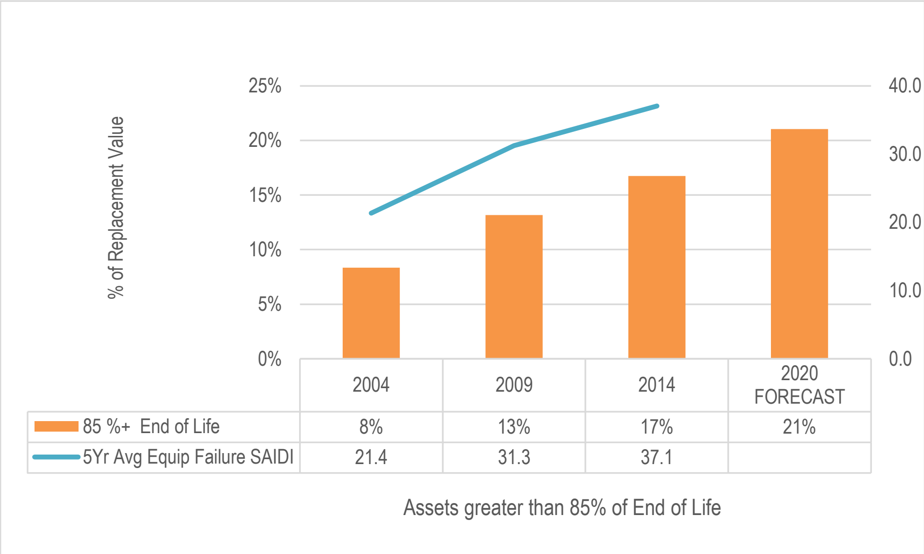
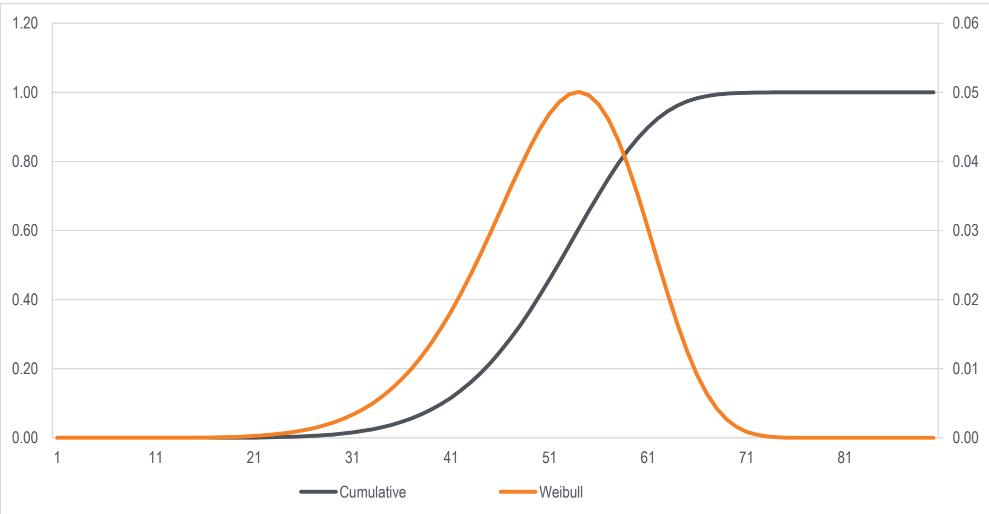


Figure 10-3 shows a strong correlation between the percentage of assets beyond 85 per cent of their asset life and the contribution to SAIDI from equipment failure. The figure predicts that by 2020, 21 per cent of our assets will fall within this age category, with the consequence that SAIDI will continue to increase significantly as a result of equipment failure.

The relationship between asset age and the probability of asset failure is well known. It is reflected in the Weibull probability density function, which depicts the distribution of failure rates for a particular asset class. Figure 10-4 shows the Weibull probability density function for an asset with an expected life of 55 years. It indicates that approximately 75 per cent of assets will remain in service at 47 years (with 15 per cent of life remaining). At this age, however, the rate of failure (shown by the slope of the blue line) increases markedly, exposing customers to increased risk of deteriorating reliability performance through equipment failure.

Figure 10-4: Weibull distribution for an asset with 55 years of expected life



As already noted, the Rules require, and our customers expect, us to maintain reliability. Consistent with this requirement, the AER's STPIS will set reliability targets for the forthcoming regulatory period based on average performance over the previous five years. Based on our latest data, to achieve average historical SAIDI performance, we would need to improve our performance from 78 SAIDI minutes in 2014 to approximately 68 SAIDI minutes.

As explained in the next section, we adopt a prudent, holistic approach to maintaining reliability. Our approach recognises that we must find smarter ways of meeting our regulatory obligation to maintain reliability and meet our customers' expectations. This holistic approach recognises that Replacement, Augmentation and ICT capex each play an important role in maintaining network reliability at minimum life cycle cost. We discuss our holistic approach to maintaining reliability in section 10.2.3.

In addition to supporting the achievement of our reliability objectives, our ICT capex requirements in the forthcoming regulatory period will also be driven by:

- The new regulatory arrangements relating to AMI meters, and the allocation of core ICT systems to standard control services;
- The "Power of Choice" reforms; and
- The AER's new RIN reporting expectations.

Our Augmentation capex must also address capacity constraints on our network, recognising the spatial variations in network demand and capacity limitations.

While there are pressures for increased capex in the area of Replacement, our customers rightly expect us to continue to improve our efficiency. While we will continue to find efficiencies, these will not be sufficient to reverse the upward pressure on capex.

In comparison with our peers, there is much less scope for us to find efficiencies. In particular, there are three aspects to our performance that set us apart from DNSPs in other States:

- Our competitively tendered outsourcing arrangements encourage our service providers to strive to maximise efficiency, and ensure that the fees we pay reflect efficient costs;
- We are one of the most efficient DNSPs because we adopt a probabilistic approach to network planning, which balances reliability performance and network expenditure to minimise total costs to customers; and
- We have continued to manage an ageing network within the limitations of regulatory capex constraints to maintain public safety.

Our customers therefore already benefit from a much leaner network with a lower cost base. This fact is reflected in the AER's benchmarks, which show that our costs per customer are the lowest of all DNSPs in Australia. We discuss these benchmark results in more detail later in section 10.8.

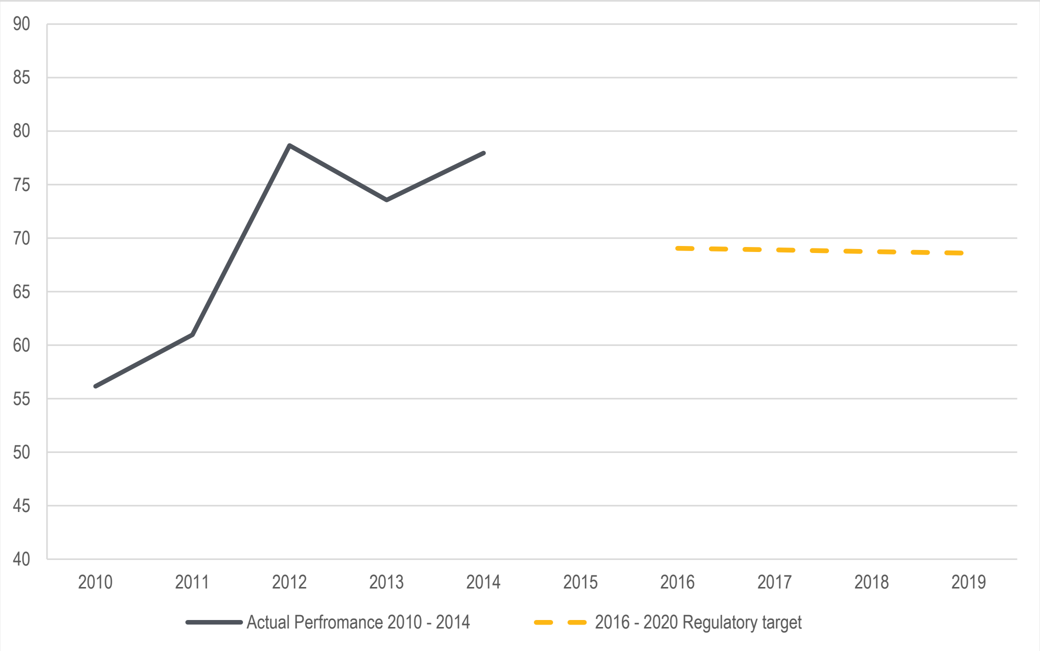
Our leaner network, however, also means that there is no excess capacity to absorb increased network risk or the consequences of asset failures. As a result, our capex requirements will increase in the forthcoming regulatory period, principally to address the increased number of assets approaching the end of their lives and the declining network reliability. Importantly, our approach to asset management planning ensures that the required outcomes will be delivered efficiently.

10.2.3. Prudent Holistic Approach to Maintaining Reliability

This section provides a high-level explanation of how our expenditure plans maintain reliability at minimum life cycle costs.

Figure 10-5 presents the target to maintain reliability in the next regulatory period, in the context of current network performance. Our target is based on our historical average performance over the past five years, and is estimated to average 68.3 minutes unplanned SAIDI for the period. Our performance for the last three years is well above this average, and was 78 minutes in 2014. In order to maintain reliability in the next regulatory period, we must return our performance to our historical five year average by closing the gap by around 10 minutes.

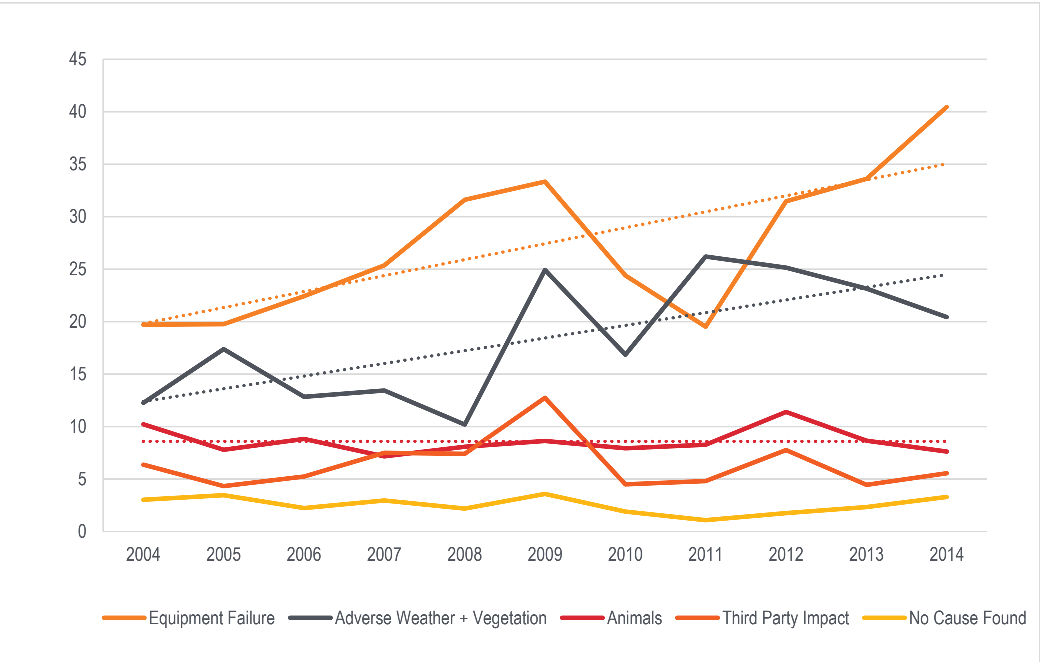
Figure 10-5: Historical SAIDI performance and proposed targets



As already noted, as the SAIDI performance is deteriorating, effectively we need a step improvement in performance to return to the historic average. This step improvement is depicted in the above figure.

In order to determine the most efficient way to achieve the 68.3 minute target, we have assessed the SAIDI causes and their historical trends as shown in Figure 10-6.

Figure 10-6: Causes of deteriorating trend in SAIDI performance



In targeting those areas where current unplanned SAIDI can be reduced to arrest the decline in network performance, we have focused on the areas and programs where we can have a significant impact at least cost. In this regard:

- Equipment failure is the largest cause of unplanned SAIDI and is increasing due to the growing volume of assets approaching the latter stages of their lives. This clearly needs to be a focus of our replacement activity;
- Adverse weather and vegetation management, the second largest causes of unplanned SAIDI, cannot be significantly influenced in a cost effective manner because:
  - We recently enhanced our vegetation management activity following legislative changes; and
  - It is comparatively expensive to upgrade networks beyond their original design criteria to reduce the impact of weather on network performance.
- Animals, third party and “no cause found” are all small causes of unplanned SAIDI that have not shown any trend increase, and whilst some initiatives may be cost effective, they have a limited overall impact on network performance.

Given the above observations, it is appropriate for us to focus our efforts on addressing the contribution of equipment failure to unplanned SAIDI. In addition, programs that reduce all causes of unplanned SAIDI may also have a significant impact. In this regard, Table 10-4 shows, at a high-level, the relative contribution that can be made by the different capex categories to meeting target network reliability.

Table 10-4: Potential Contributions to maintaining network reliability

Capex category	Potential Contribution to reliability
Connections	Nil – Connects new customers and load
Augmentation	Medium – Reduces risk of load-shedding and asset failure through over-loading
Replacement	Strong – Replaces assets at end of life. Includes specific programs to address network performance
Non Network – Information Technologies	Medium – Provides enablers or a foundation from which to address network performance
Non Network – Fleet, Depots	Low – Provides enablers or a foundation from which to address network performance

In this context, our expenditure plans for the forthcoming regulatory period work together to maintain reliability. The primary areas that contribute to this outcome are Replacement, Augmentation and ICT capex.

Replacement capex

In broad terms, there are three aspects of Replacement capex that drive reliability performance:

<u>Replacing assets at end of life</u>

Due to the age profile of the network, many asset classes have an increasing proportion of the assets nearing the end-of-life and an increased level of Replacement capex is required to address the corresponding deterioration of network performance and to maintain network safety.

We have prepared Asset Life Cycle Strategies (LCS) for each asset class. These detail our strategies for managing the assets to achieve desired outcomes at least life cycle cost. Targets for network performance are set for each asset class considering our historical performance, industry benchmarks, and what may be reasonably achievable for our proposed cost considering the specific circumstance of the asset class. We expect that several asset classes will make a negative contribution to network performance, as it would be inefficient to address deteriorating performance in these particular cases through additional replacement of assets. Instead, we have proposed more efficient ways of maintaining reliability, as outlined below.

Further information on our asset replacement plans is provided in our relevant explanatory statements and Life Cycle Strategies (LCS). These plans also include opex initiatives to minimise total life cycle costs, such as improved inspection practices in order to facilitate better targeting of Replacement capex.

<u>Network performance capex</u>

Network performance capex contributes to achieving reliability targets by reducing the frequency of some outages, minimising the number of customers affected by outages, and restoring supply to customers as quickly as possible.

Some of the programs included in our network performance capex are as follows:

- Additional remote control gas switches (RCGS) and automatic circuit reclosers (ACR) will be installed in selected locations to enable a faulted section of a feeder to be isolated, and supply to be restored to remaining customers on unaffected sections in a short period of time;
- Communications for existing RCGSs and ACRs will be improved to increase the effectiveness of these existing schemes;
- Fuse savers will be installed in selected locations to allow successful reclose for transient faults that would otherwise result in fuse operation and extended outages for affected customers; and
- Additional animal proofing will be installed to reduce the frequency of animal faults on the overhead network.

Network performance capex programs are ranked and selected based on their ability to maintain network reliability at least cost.

Further information on these initiatives is provided in the Network Performance Asset Strategy (PL-2300).

<u>Operational technology</u>

Operational technology investments are smart technology solutions to address a variety of drivers including maintaining network reliability. This includes projects for fault location identification and asset condition monitoring. For instance, condition monitoring of transformers allows us to defer the replacement of zone substation transformers to as close as practicable to the end of their lives. Fault location identification enables us to locate and rectify a fault and restore supply as quickly as possible.

Our Replacement capex includes approximately $38 million for operational technology projects over the forthcoming regulatory period that contribute to maintaining reliability, noting that most of our operational technology projects provide benefits across several drivers, including safety and power quality compliance.

Further information on these operational technology initiatives is provided in our explanatory statements supporting this Regulatory Proposal.

Augmentation capex

Augmentation capex increases the capacity of our network to meet peak demand. If sufficient capacity is not available at times of peak demand, supply to some customers will be interrupted - resulting in deteriorating supply reliability. In addition, overloading of equipment due to insufficient capacity can result in asset failure. Augmentation capex therefore has a role to play in maintaining reliability.

The contribution of Augmentation capex to network performance for the forthcoming regulatory period will be the same as it was for the current regulatory period, resulting in no net impact. Our approach to VCR as explained in section 10.9 is consistent with this outcome.

Information technology

ICT investments include projects that facilitate faster supply restoration and enable more efficient asset management.

Projects such as our DMS feeder load management enhancement will provide our Network Control Centre operators with better information, enabling them to make more informed decisions during major outage events.

Our AMS capability upgrade and RIN reporting projects substantially increase the capability of the systems that underpin the AMS, and will improve the quality and efficiency of asset replacement decisions. Due to implementation timing, these projects will deliver the majority of benefits beyond 2020.

These examples illustrate the importance of our ICT investment in maintaining reliability in the forthcoming regulatory period, and enabling more efficient long-term asset management.

Further information on the specific ICT initiatives that will contribute to maintaining network reliability is provided in section 10.13 and in individual project justifications.

Summary

It is evident from the above discussion that we are adopting a prudent, holistic approach to the task of 'maintaining reliability' to ensure that this objective is achieved efficiently. This holistic approach recognises the contributions made by each capex category (in addition to opex) so that our total expenditure is properly calibrated to the task.

10.2.4. Why our forecasts comply with the Rules

As already noted, the Rules require us to submit a total capex forecast that achieves the following capex objectives:

- To meet the expected demand for our services;
- To comply with our safety and regulatory objectives;
- To maintain network reliability; and
- To maintain the safety of our distribution network.

In addition, the AER must accept our forecasts if it is satisfied that they reasonably reflect each of the following capex criteria:

(a) the efficient costs of achieving the capital expenditure objectives;

(b) the costs that a prudent operator would require to achieve the capital expenditure objectives; and

(c) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives.

This sub-section provides a high-level explanation of why our forecasts should be accepted by the AER. It should be read in conjunction with our capex sub-category overview papers that provide further detail about why each sub-category of our capex forecasts meet the Rules' requirements.

In relation to the efficiency criterion:

- Our forecast work volumes are formed through robust asset management plans and investment governance arrangements, further details of which are provided in sections 10.4 and 10.5 below;
- Our Replacement capex is validated by the AER's Repex model and they fall within the reasonable range – we have provided an independent expert report from Nuttall Consulting which addresses this matter;
- Our Augmentation capex is validated by the AER's Augex model – we have provided an independent expert report from Nuttall Consulting which addresses this matter;
- Our forecast unit costs are derived from our competitively tendered contracting model. The efficiency of our business model is demonstrated by our benchmark performance with our peers in other states, which shows us to be close to the frontier (see sections 6.2 and 10.8); and
- Our ICT capex forecasts are in line with industry benchmarks and would have been lower than the two previous periods, were it not for regulatory requirements associated with Power of Choice and RIN reporting.

In relation to the prudency criterion:

- Our Replacement capex has been calibrated to arrest the trend decline in network reliability, and return performance to 'maintain reliability', consistent with our customers' expectations and the Rules' requirements, as explained in section 10.2.3;
- Our environmental, legal and safety obligations are reflected in our asset management plans and strategies; and
- Our LCS and work programs actively manage risk to ensure that work programs are both prudent and efficient.

In relation to the demand forecast and cost input criteria:

- Our Augmentation capex is driven by the demand forecasts presented in Chapter 9 of this proposal; and
- The costs of labour and materials are derived from competitively tendered contracts, and are escalated in accordance with forecasts provided by BIS Shrapnel.

10.2.5. Key assumptions – capex

The key assumptions underpinning our capex forecasts are that:

- The maximum demand and customer growth is consistent with our forecasts in Chapter 9;
- The customer connection growth is consistent with our forecasts in Chapter 9;
- Customers value reliability in accordance with the AEMO 2014 VCR survey, and it is therefore appropriate to use:
    - For Augmentation and Replacement capex on power transformers, a VCR based on AEMO's 2014 VCR survey results calculated on data specific to the summer peak period; and
    - For Replacement capex on all other assets, a VCR based on AEMO's 2014 VCR survey results calculated on data across all sectors and all seasons.
- The forecast capex will maintain, but not improve, network reliability; and
- Our current legislative and regulatory obligations will not change materially, other than as identified in this Regulatory Proposal (being for Power of Choice, Energy Safe Victoria Regulations and the AER's RIN reporting requirements).

Our Directors have provided a certification of the reasonableness of these key assumptions in accordance with clause S6.2.2(6) of the Rules.

10.3. Our business transformation

We implemented a business transformation project during the current regulatory period. We foreshadowed this transformation to the AER in our 2009 Regulatory Proposal and in our 2010 Revised Regulatory Proposal.

Our business transformation project built on the benefits that our previous business model had achieved, but it has created greater flexibility to manage future change and risk, and to deliver better value to our customers.

We adopted a 'best of breed' contractor model, in which we and our customers obtain the cost and service benefits from the best available contractors. Best of breed contractors are specialist service providers that successfully operate in a particular field on a national and international basis, bringing specialist knowledge, skills and economies of scale and scope. They are sought by clients, like us, for outsourcing projects, and have a proven track record of winning tenders and delivering benefits to their clients.

The new business model is based on splitting our network into two regions with separate Network Operations Services suppliers for each region.

We undertook a competitive tender process to identify our preferred suppliers. A total of 61 potential suppliers submitted responses to our Expression of Interest, of which a total of 36 respondents were assessed as being "Prequalified Respondents" and capable of providing some of the services being tendered. This level of response – which was subsequently shortlisted to seven – demonstrated the competitive nature of the tender process and confirmed the market's appetite for our new business model. We adopted strict probity protocols to ensure the integrity of the tender process.

We compared the tendered costs (including 'restructuring' or 'transformation' costs) with other options, including a projection of our existing cost structure at that time.

Tenix was the successful tenderer on the basis that it would deliver much improved outcomes, demonstrating the benefits of our proposed restructuring and "best of breed" model.

Our previous service provider, Jemena, had a right under our Operating Services Agreement (that expired on 30 June 2011) to match Tenix's winning bid from the tender.

We established two regions within our network for the purpose of procuring operations services, and Tenix and ZNX (a Jemena subsidiary) became the Network Operations Services suppliers for those two regions.

The new business model optimises the mix of services to be provided internally and those to be procured through outsourced contracts. It establishes best-practice procurement arrangements for those outsourced services. The majority of our capex and opex is exposed to continuous competitive pressure between our two service providers, while ensuring that each network region is sufficiently large to avoid inefficiencies that may arise with smaller packages of work.

An important outcome of the new business model is ensuring that best practice contractual and governance arrangements are in place. These have been reflected in Operational and Management Services Agreements (OMSAs) with each service provider. The OMSAs have been designed to create a collaborative contractual relationship between us and our service providers to achieve our desired outcomes, and to deliver these as efficiently as possible.

Our business transformation and the resulting benefits could not have been achieved without the successful completion of a major ICT core systems replacement program during the 2011 to 2015 period.

During this period, we successfully delivered several critical major ICT projects, including a major SAP ERP replacement, a system separation project, two data centre relocations, updates of our distribution management system and upgrades of market systems. We completed these major projects in line with their individual business cases. The overall 2011 to 2015 ICT program will be delivered in line with the AER's allowance for the current period.

As a result of the ICT capital program in the current period, we have:

- Implemented a suite of foundation systems that provides a robust platform to meet future customer, business and regulatory requirements;
- Removed all dependence on the ICT capability of Jemena Asset Management;
- Consolidated and rationalised legacy applications; and
- Consolidated the systems implemented for AMI with our other corporate systems.

As part of the business transformation, we have established a new ICT operating model. In line with our overall business operating model, we now have a small internal ICT team of approximately 20 employees which has responsibility for ICT asset management, strategy and management of the ICT project portfolio.

Our ICT projects are delivered by a panel of external service providers. The panel was formed following a formal procurement process. At the start-up phase of each ICT project, formal quotations are requested from two or more of the service providers on our panel. Work is then commissioned under rates and commercial mechanisms defined when the panel was established. In some cases, service provider resources are supplemented with our staff and/or other contract resources. In addition, we have established a specific contract with a commercial service provider for smaller projects and enhancements to existing systems. All ICT operations are carried out by specialist ICT service providers, again appointed following commercial tendering processes.

Our ICT operating model provides us with access to leading ICT expertise at competitive, market-tested rates. The model provides us with the flexibility to bring on resources as required to meet fluctuating patterns of project demand.

Our new business model therefore builds on the cost efficiencies that our earlier outsourcing arrangements delivered, but further improves our financial and operational performance by:

- Providing us with strengthened and increased internal management resources, thereby providing us with greater strategic management capability;
- Internalising the asset management and IT strategy functions, thereby further strengthening the company's capabilities in these critical areas of our core business;

- Removing our reliance on any one contractor and adopting a "best of breed" outsourcing model that includes multiple contracts and multiple service providers;
- Adopting best practice forms of collaborative contracting with suppliers while maintaining continuous competitive pressures on contractors throughout the contract period;
- Ensuring high levels of transparency and robust governance arrangements in all contracts we enter into for the procurement of business inputs;
- Achieving the right balance between delivering operating cost efficiencies and maintaining an appropriate longer term risk profile for asset performance;
- Addressing historical regulatory concerns about holistic service outsourcing to a related party;
- Demonstrating efficiency through market-based pricing;
- Adopting pricing and incentive structures in the contractual arrangements that are best practice and fit-for-purpose having regard to the objectives of providing efficient cost and service outcomes for us and our customers in the short, medium and long term;
- Reducing the risk of inefficient or sub-optimal service performance, by adopting a commercial framework that is free of mechanisms that provide incentives to service providers to engage in under or over-servicing;
- Reducing financial, regulatory and service performance risks that can arise through a misalignment of asset owner and service provider objectives, by establishing an alliance contract based on jointly agreed objectives and budgets, and a shared focus on how to achieve the best outcomes; and
- Enabling us to adapt to the changes that are impacting DNSPs worldwide by having a business structure that has greater strategic management capability and flexibility.

10.4. Our expenditure governance framework

We have a high degree of confidence that we will deliver our total capex forecast. This is based upon our proven ability to deliver against our capex allowance in the current regulatory control period. We recognise the importance of sound asset management in ensuring the efficient delivery of services that meet customers' and stakeholders' current and future needs. Network design, network construction, maintenance, operations and asset investment are vital components of asset management. Effective asset management directly impacts customer service, safety and shareholder value.

Having completed our business transformation and gained valuable experience in working with our Network Operations Services suppliers and our ICT service providers, we have established a set of robust capital governance processes (i.e. our investment framework). This framework enables us to be confident that we are making prudent and efficient investment decisions that will deliver a satisfactory and sustainable return on our assets in a legally and environmentally compliant, safe and sustainable manner.

Our Investment Framework comprises a number of components being the Electricity Distribution Price Review (EDPR) Steering Committee, the Capital Investment Review Board (CIRB), the ICT Executive Forum and the Business Governance Framework. Further details on each of these components are provided below.

10.4.1. EDPR Steering Committee

The EDPR Steering Committee was formed in mid-2014 and consists of key members of our Executive (the Chief Executive Officer (CEO), Chief Financial Officer (CFO), General Manager (GM) Networks Electricity and GM Regulation). It has met fortnightly since its establishment. It determined our strategic position on key issues and endorsed this Regulatory Proposal for submission to the Board to approve lodgement with the AER.

The EDPR Steering Committee's role has included evaluating and approving the proposed network and ICT capex for the forthcoming regulatory period. The proposed capex was subjected to our business governance framework set out in section 10.4.3, before being submitted to the EDPR Steering Committee. This has ensured that our capex proposal was subjected to rigorous analysis and justification before being submitted to the EDPR Steering Committee for consideration.

10.4.2. Network Capex Governance

During the course of a regulatory period, network capex is subject to a review by CIRB. The CIRB's scrutiny of capex proposals ensures that all significant investment is prudent and efficient.

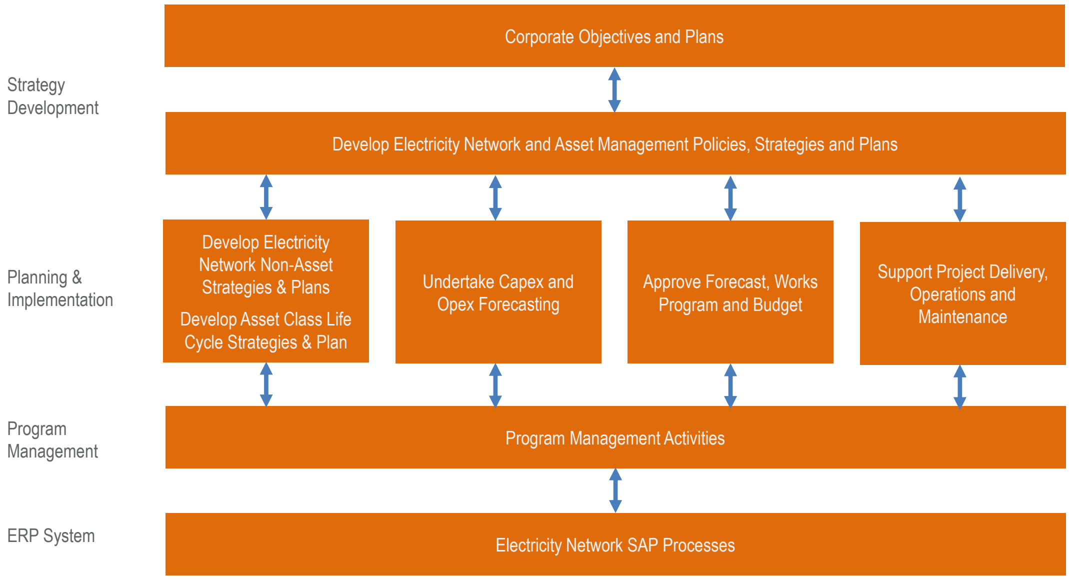
The objectives of the CIRB are to:

- Provide a consistent and rigorous approach to investment decisions;
- Ensure that an appropriate level of governance is applied to all significant investment decisions through the appropriate level of management scrutiny;
- Demonstrate to our Board, shareholders and other key stakeholders that investments are efficient and prudent; and
- Ensure that all investment accords with our compliance obligations and regulatory requirements.

10.4.3. Business Governance Framework

The Electricity Network Governance Framework is a hierarchy of business processes that support the development and integration of the asset management activities. The framework takes a governance approach, outlining business rules and responsibilities in relation to key deliverables. Key components are explained below.

Figure 10-7: Electricity network business governance framework



Each main component of the framework is described below.

Strategy development

The key corporate business planning outputs are the following documents:

- Corporate Business Plan;
- Corporate Vision and Mission Statements; and
- Corporate Risk Appetite Statement.

These documents provide overarching guidance for the development of more detailed Asset Management policies, strategies and objectives.

The Asset Management policies guide our asset and non-asset class planning and decision making, and the development of our works program.

Activities undertaken to develop strategies and objectives include:

- Analysing external long term trends and potential strategic impacts;
- Determining long term future scenarios to be addressed;
- Determining strategies to address selected scenarios; and
- Executive Leadership Team endorsement of scenarios and strategic response.

Further details of our Asset Management Framework are provided in section 10.5 below.

Planning and implementation

Planning and implementation activities take place in alignment with the Corporate Business Plan and Asset Management Policies.

Asset and non-asset class strategies and plans are updated annually, along with capex and opex forecasting and the development of the Capex and Opex Works Program (COWP).

The COWP is provided to our Service Delivery group to oversee the implementation of the program of works by our service providers.

Program management

Program management activities are undertaken on an ongoing basis to manage the program of works. Regular interaction between our Corporate Finance and Service Delivery groups occurs throughout this phase.

Enterprise Resource Planning (ERP) Systems

ERP systems underpin all asset management activities and key systems and processes. Asset information is collected, stored, utilised and managed by us and our service providers.

10.4.4. ICT Governance

Our ICT governance structure provides oversight, guidance and direction to our ICT capex program. A high-level committee, including key members of our Executive, meets monthly to approve new projects, track and monitor existing projects and ensure overall alignment of ICT expenditure with business, customer and regulatory requirements.

We will continue to operate a robust ICT governance framework over the forthcoming regulatory period.

Currently, our ICT governance framework consists of the following joint business ICT governance and advisory groups:

- ICT Executive Forum – this is our peak ICT governance forum in which our Executive Management Team (including the CEO) oversees all ICT capex and ensures that ICT investment is aligned with business strategies and priorities;
- Architecture Review Board – this Board ensures that proposed solutions are aligned with business and ICT architectural requirements and total cost of ownership considerations;
- Information Security Management System (ISMS) Governance Group – this group oversees the implementation of the ISMS across our business and ICT functions;
- Project Steering Committee – a project steering committee is formed for every major project; and
- Application Change Control Board – this body approves and prioritises small enhancements and business change requests.

- Quarterly business engagement forums, coordinated by the Principal Consultant, Customer and Technology, are used to refine, and provide a health-check of, ICT alignment. Various user groups are formed to support knowledge sharing and collaboration.

10.4.5. Capex-opex substitution

In developing our capex forecasts, we have considered the substitution possibilities between capex and opex as well as substitution between different sub-categories of capex. These substitution possibilities are considered through 'trade-off' and / or synergy analysis and are overseen by the various management expenditure committees, discussed above. They are responsible for reviewing our capex and opex forecasts to ensure that they are prudent and efficient before being aggregated and provided to the Board for approval. Further specific details of our analysis of capex-opex substitution are provided in sections 10.10, 10.12, 10.13, and 10.14, and the relevant supporting documents.

10.5. Asset Management Framework

Our asset management framework and systems are aligned with key elements of ISO 55001. These processes and systems ensure that network risks and costs are systematically analysed and optimised. The systematic consideration of risks and costs underpin our capex forecast.

The following key asset management principles describe the overarching objectives of our asset management framework. We:

- Employ good asset management practices to prudently manage and operate the assets over their total life cycle;
- Minimise our long-term cost structure considering the potential downturn in future grid consumption;
- Build our reputation as a trusted company with customers and stakeholders by striving for active industry leadership, agility, reliability, safety and good customer service in light of changing customer and community expectations;
- Meet all legal and regulatory requirements;
- Adhere to the relevant Australian, international and industry standards and any other requirements to which United Energy subscribes;
- Prudently manage reasonably foreseeable and critical credible safety hazards and risks to as low as reasonably practicable;
- Develop high performance operations by engaging our people and having the right skills and capabilities within our business;
- Embed continuous improvement and innovate to drive efficiency; and
- Monitor and evaluate appropriate metrics to effectively manage our network.

Our Asset Management Strategy and Objectives (Document No UE PL 2050) articulates the principles listed above, and draws on our corporate strategy and roadmap to develop specific asset management objectives and strategies. These objectives and strategies are further developed and advanced through the Asset Class LCS and Non-asset Specific Strategies and Plans. These strategies and plans feed into our overall Asset Management Plan and capex/opex works program, which is prepared annually, and provides a rolling view of:

- Our overall asset management direction and focus; and
- Our capex (for 10 years) and opex forecast (for five years).

Our capex forecasts for the forthcoming regulatory period are 'business as usual' forecasts, underpinned by the asset management framework, strategies and work programs described above.

10.6. Deriving the unit rates for our Augmentation and Replacement capex forecasts

Our Augmentation and Replacement capex comprises:

- Unitised projects – these projects that are forecast using standardised unit rates; and
- Non-unitised projects – these are individually costed projects.

10.6.1. Unitised projects

We forecast the costs of unitised projects by multiplying work volumes by unit costs.

Our unit rates are sourced from our OMSAs with our service providers. These rates are the best we have available for developing our capex forecasts given that they are market tested through the establishment of the OMSAs under competitive arrangements, as explained in section 10.3. They are based on the actual outturn costs (AOC) that we incurred from 1 July 2013 to 30 June 2014.

We derive the annual OMSA rates using the prescribed OMSA budget setting process. Under the agreements, the OMSA rates are applied to the forecast volumes to determine the target outturn costs (TOC). We reimburse our service providers for their actual costs during the year, which must conform to the cost reimbursement rules under the OMSA – we refer to this as Limb 1. We also pay a contribution fee – that we refer to as Limb 2 – that is an agreed mark-up on Limb 1 costs. Together, Limb 1 and Limb 2 comprise our AOC.

The AOC are considered during the budget setting process to develop the following year's OMSA rates (and therefore the TOC, having regard to the volumes). This process is largely finalised by March and applies from 1 July the same year (i.e. on a financial year basis). The OMSAs incentivise our service providers to achieve the lowest sustainable cost of service provision and, in this way, the target (TOC) and actual (AOC) costs converge over time.

10.6.2. Non-unitised projects

Project costs are developed for work that has a higher level of complexity, which means that it cannot be costed upfront based purely on unitised rates. We forecast project costs using a combination of:

- Actual historical costs from previous completed projects;
- Expert estimation tools;
- Statements of Works from our Service Providers based on their procurement policies and processes;
- Open tender processes;
- Customised cost estimates, where there is no relevant benchmark; and
- Verification by an Independent Estimator.

In this way, our non-unitised projects require tailored cost estimates.

The unit rates used to derive expenditure forecasts for the Connections, Non-network ICT and Communications and Non-network General capex categories are described in sections 10.11, 10.13 and 10.14 of this document. Further details are also contained in the respective Capex Overview Papers that we have provided to the AER with this Regulatory Proposal.

10.7. Cost escalators

We have escalated our capex forecast for changes in the real input costs of labour and materials expected over the forthcoming regulatory period.

The escalators applied to materials were developed internally using raw-commodity level data provided by an independent expert, BIS Shrapnel, to forecast real material cost escalations for the forthcoming regulatory period.

A copy of BIS Shrapnel's report entitled "Real Labour and Material Cost Escalation Forecasts to 2020" has been provided to the AER as an attachment to this Regulatory Proposal.

The methodology used to derive the material cost escalator involved applying the network-related materials escalators (at the raw-commodity level) provided by BIS Shrapnel (i.e. wood, aluminium, copper, steel, oil, concrete etc.) to the estimated mix of these material components required to construct and/or maintain our distribution network. This provided a weighted average escalator for each year that has been applied to our capex forecast.

The escalator applied to labour is consistent for both capex and opex and is detailed in section 11.4.5 below.

We have provided to the AER with this Regulatory Proposal the model that we have used to derive the labour and material escalators.

10.8. Capex and Asset-Related Benchmarking

We have reviewed the benchmarking that the AER has undertaken in its 2014 Annual Benchmarking Report and in its recent Draft Distribution Determinations for the NSW and ACT DNSPs. We generally support the outcomes of this benchmarking, which show that we are highly efficient compared with our peers.

The AER used a variety of benchmarking techniques, based on both partial productivity measures (PFP) and MTFP analysis.

10.8.1. Partial productivity measures

The AER's 2014 Annual Benchmarking Report did not directly benchmark DNSPs' capex, because it recognised that assets can last multiple regulatory periods and capex can fluctuate from year to year and period to period.

Instead, the AER measured the annual cost of assets that are used to provide services to customers. This asset cost therefore represents the amount that customers annually pay for the asset inputs of DNSPs. It is the sum of the DNSP's depreciation and return on capital.

The AER assessed that, regardless of customer density, we have:

- The lowest asset cost per customer in the NEM – this is illustrated in Figure 13 on page 26 of the AER's Report; and
- The lowest asset cost per MW of maximum demand in the NEM – this is illustrated in Figure 27 on page 41 of the AER's Report.

The AER also benchmarked DNSPs' annual total costs by adding together their asset costs and opex. We were assessed as having:

- The lowest total cost per customer in the NEM – this is illustrated in Figure 14 on page 27 of the AER's Report; and
- The second lowest total cost per MW of maximum demand in the NEM – this is illustrated in Figure 28 on page 42 of the AER's Report.

The AER released its Draft Distribution Determinations for the NSW and ACT DNSPs in November 2015. Appendix 6 focuses on capex. It shows that we have:

- The lowest regulatory asset base per customer in the NEM – this is illustrated in Figure 6-6 on page 6-27 of Attachment 6 of the AER's report; and
- The lowest regulatory asset base per MW of maximum demand in the NEM – this is illustrated in Figure 6-7 on page 6-28 of Attachment 6 of the AER's Report.

10.8.2. Multilateral total factor productivity (MTFP) and partial factor productivity (PFP) analysis

The AER engaged Economic Insights to undertake MTFP and PFP analysis. The AER relied on this analysis in both its 2014 Annual Benchmarking Report and in its Draft Determination for the NSW and ACT DNSPs.

The MTFP analysis compared the relationships between DNSPs' outputs (energy delivered, customer numbers, ratcheted maximum demand, reliability and circuit line length) and inputs (opex and capital). The analysis split the capital input into five components – overhead distribution lines, overhead subtransmission lines, underground distribution cables, underground sub-transmission cables, and transformers and other.

On the basis of this MTFP analysis, the AER concluded that we were consistently amongst the three most productive DNSPs in the NEM over the analysis period, 2006 to 2013. This is illustrated in Figure 16 on page 31 of the AER's 2014 Report.

The PFP analysis considers the productivity of transformers, overhead lines and underground cables together. Again, we were consistently amongst the three most productive DNSPs in the NEM over the analysis period. This is illustrated in Figure 18 on page 33 of the AER's 2014 Report.

10.8.3. Conclusions on benchmarking

We draw the following conclusions from the AER's benchmarking analysis:

- We are the most efficient DNSP in the NEM in using our assets – this is consistent with the fact that we have the most highly utilised network in the NEM;
- Each of the benchmarking techniques that the AER has used supports the fact that our capex is efficient and that we are operating at or close to the efficient frontier of DNSPs in the NEM. We do not advocate relying on any one benchmarking technique, however the consistent body of benchmarking results supports this conclusion;
- By its nature, there should be "winners" and "losers" from the use of benchmarking – not everyone should be a winner and not everyone should be a loser. DNSPs that are performing well relative to their peers should be recognised as performing efficiently and be rewarded accordingly. Businesses that are performing poorly relative to their peers should be transitioned to efficient levels of expenditure over time. It is unrealistic to expect that all DNSPs can be performing at the same levels immediately. This complements the role of the AER's Capital Expenditure Sharing Scheme (CESS) as a key regulatory mechanism for facilitating this transition and recognises that, by its nature, achieving efficiency is a continuous journey;
- We benchmark favourably with our peers in spite of differences in our operating environment. We are an urban DNSP with significantly less underground network than CitiPower, whom the AER has identified under some benchmarking techniques to be the frontier DNSP. We note that CitiPower enjoys the advantage of having a small network area;
- We have sustained an efficient level of performance over a long period of time. We have not just arrived at our efficient levels of capex recently. This means that assessments of our efficiency are not just a function of which year, or years, are chosen for the benchmarking analysis;
- Our new business model – that has resulted from our recent business transformation program – is successful and is delivering efficient capex outcomes. The new business model provides a strong basis for us to continue to deliver efficient outcomes;
- We have continually responded to the incentives that the AER and, prior to this, the ESCV, have provided to us through the regulatory regime. This is reflected in the efficiency of our capex. Our customers are sharing in the resultant benefits; and
- We are delivering value for money to our customers through our efficient capex.

10.9. Value of customer reliability

In order to determine the economically optimum level of investment, it is necessary to place a value on supply reliability from the customers' perspective. It is recognised that this value may depend on the customers involved (and the duration of the outage) and estimating such a value is inherently difficult. It is common practice by many DNSPs to use an average marginal value of reliability – the VCR – for this purpose.

Clause 6.5.7(a) of the Rules requires us to submit a capex forecast that maintains current levels of reliability. Furthermore, our customers indicate that they do not want further deterioration in reliability. These requirements seem to conflict with the recent reductions in AEMO's headline VCR that it published in 2014, which suggest reliability should be permitted to deteriorate further.

In order to address this apparent contradiction – and to achieve the requirements of the Rules while maintaining consistency with AEMO's 2014 VCR survey results – we have adopted the following approaches.

For Augmentation and Replacement capex on power transformers, we have applied a VCR using AEMO's 2014 VCR survey results calculated on data specific to the summer peak period only. This is because investment in Augmentation and the availability of power transformers both ensure we meet reliability performance predominantly on hot summer days. The document UE GU 2208 VCR Application Guidelines provides detailed calculations of this VCR based on the AEMO 2014 VCR survey results. In developing our VCR Application Guideline for Augmentation activities, we have applied the recommendations from section 2.3, 2.4 and Appendix B of AEMO's VCR Application Guide. These sections of AEMO's Guide recommend reweighting VCRs to take into account:

- The time that the expected unserved energy is occurring;
- The duration of outages;
- The mix of customers involved; and
- Local knowledge about our customers;

to better reflect the costs to consumers of network constraints. AEMO's VCR Application Guide recommends reweighting the VCR for network planning purposes to reflect the time of year when unserved energy is expected to occur.

For Replacement capex on all other assets (i.e. other than power transformers), we have assumed the Victorian headline VCR using AEMO's 2014 VCR survey results calculated on data across all sectors and all seasons.

The use of these two approaches reflects the fact that customers value reliability differently on hot summer days compared to other times.

10.10. Augmentation capex

10.10.1. Overview

Augmentation capex is driven by the regulatory obligations in Chapter 5 Part B of the Rules regarding Network Planning and Expansion. This capex is required to meet or manage capacity constraints in the electricity distribution network as a result of growth in maximum electricity demand. We also have obligations under the Victorian Electricity Distribution Code that influence the level of Augmentation capex we must undertake.

If inadequate augmentation work is undertaken, customers will face an increasing exposure to load shedding as demand grows. In addition, overloaded assets are more likely to fail, which will further increase the exposure to unserved energy. Asset failures may result in increased emergency maintenance expenditure, cascading outages and deteriorating reliability of supply. Such failures are likely to occur on days of extreme temperatures (hot or cold), putting at risk the health and wellbeing of our customers.

The underlying objectives of Augmentation capex are therefore to reinforce the network when necessary and economic in order to facilitate meeting customer load growth with all plant available, while maintaining appropriate levels of performance and levels of risk for customer loss of supply in the event of a single contingency.

We have developed an efficient and prudent program of Augmentation capex that maintains existing levels of expected unserved energy, effectively a reliability-maintained program. To substantiate this approach, as discussed in section 10.9, we have calculated a VCR for our network based on AEMO's 2014 VCR survey results. As recommended in AEMO's new VCR Guidelines, we have chosen to adopt a reweighting of the VCR for the specific mix of customers in our network, the time of year that the energy at risk is incurred (i.e. the summer peak), and the expected duration of outages. This calculation is documented in detail in our VCR Application Guideline (UE GU 2208).

Figure 10-8 below shows our forecast Augmentation capex for the forthcoming regulatory period compared to our actual capex and the AER's allowance for the current period. It also shows the projection using the AER's Augex model.

Figure 10-8: Historical and forecast Augmentation capex ($M, Real 2015)

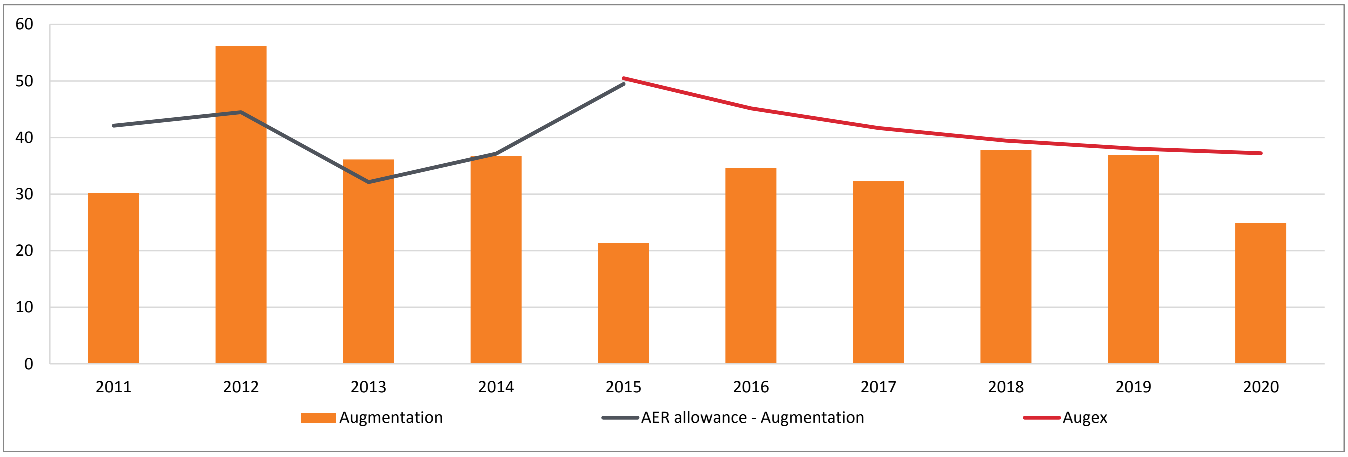


Figure 10-8 shows that:

- Actual Augmentation capex for 2011 to 2015 is less than the AER's allowance – this is attributed to revising down the maximum demand growth rates within the period as a result of increased retail electricity prices and a general slowing of the economy. We reduced our Augmentation capex in response to this change in growth;
- Forecast Augmentation capex for 2016 to 2020 is less than actual capex for 2011 to 2015. This reflects deferral opportunities created from declines in maximum demand observed at the end of the current period, and improved information on asset loadings obtained from our fleet of smart meters; and
- Forecast Augmentation capex for 2016 to 2020 is significantly lower than that forecast by the AER's Augex model. This reinforces the efficiency and prudency of our forecast capex.

Further details are provided in our Augmentation Capex Overview Paper. Table 10-5 presents our forecast Augmentation capex for the forthcoming regulatory period.

Table 10-5: Forecast Augmentation capex 2016-2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Augmentation	34.7	32.3	37.8	36.9	24.9	166.5

This forecast includes $2.5 million of non-traditional network investment (i.e. energy storage). This investment will save $0.5 million by avoiding $3 million of traditional Augmentation capex in the forthcoming regulatory period.

In addition, as we make expenditure decisions during the forthcoming regulatory period, we will assess what further opportunities there are in order to make additional savings by deferring Augmentation capex by using non-network solutions.

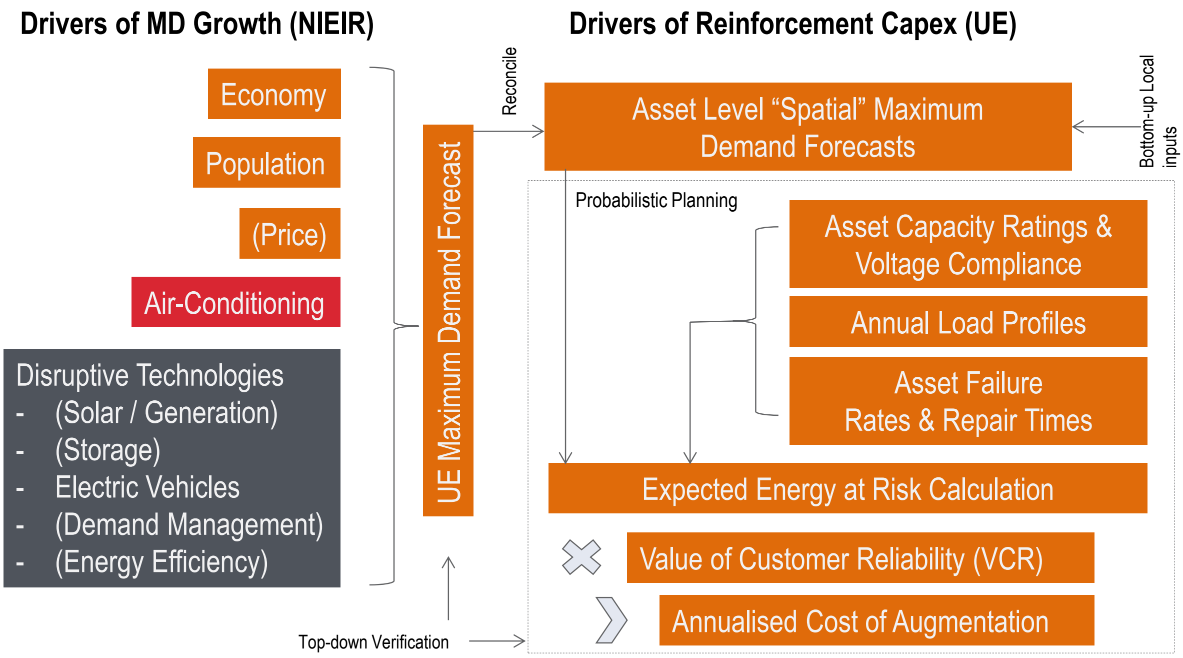
10.10.2. Key inputs and drivers

The primary driver for Augmentation capex is the growth in maximum demand within localised parts of our distribution network where there is a local capacity constraint. While we forecast maximum demand for our overall supply area ("boundary load"), it is the lower-level "spatial" forecasts that explicitly drive capex. As discussed in Chapter 9, we develop maximum demand forecasts at the transmission connection asset level, sub-transmission level, zone substation level, distribution feeder level and distribution substation level for each asset. This is further explained in our Overview Paper that justifies our maximum demand forecast.

Economic growth, population growth and increased penetration of temperature sensitive load such as air-conditioning and evaporative cooling over the last 15 years have been the major drivers for maximum demand growth in our service area. A number of potentially significant emerging developments are occurring, or are about to occur, in the way customers use their electricity and these developments will ultimately have a measurable impact on the maximum demand growth and therefore our Augmentation capex. The use of distributed embedded generation is increasing, stimulated by reduced technology cost, subsidies and increased environmental awareness. A prime example is solar PV. This trend is likely to continue and new technologies will emerge. Furthermore, EV, distributed storage and demand management applications are also on the horizon. All have the potential to impact maximum demand growth.

Figure 10-9 shows how the above drivers feed into developing our Augmentation capex forecast.

Figure 10-9 – Drivers of Augmentation capex



As detailed in Chapter 9, we prepare three plausible maximum demand scenarios – base, low and high. Our Augmentation capex forecast is based on the "base" (most likely) scenario and combinations of post-model adjustments.

We develop our forecast using a probabilistic planning approach. This economically sound approach to network planning and expansion considers the expected cost to customers losing supply in the event that demand exceeds the available network capacity, by taking into account asset capacity ratings, annual load profiles, and asset failure rates and repair times. This is done either with all plant in service or by considering the probability of a single credible contingency. The associated cost, which is determined by multiplying the expected energy-at-risk by the VCR, is then compared against the annualised cost of removing the capacity constraint. After we compare energy-at-risk with the annualised cost of removing the customer constraint, we proceed with "projects or action" when the energy-at-risk becomes greater than the annualised cost of removing the customer constraint, noting that "action" could involve network or non-network solutions.

As explained in section 10.9, the VCR we have used is based on a value derived from AEMO's 2014 VCR survey considering the summer peak period and outage durations for the expected unserved energy. VCR is an important signal for investment and determining reliability levels. In establishing a case for an augmentation project, location specific VCR values are used to reflect the different classes of customers served by the augmented facility. To satisfy the requirements of a RIT-D, a set of scenarios is applied to test the sensitivity of the economic viability of a proposed augmentation against credible variations in VCR.

Our VCR Guideline (UE GU 2208) sets out the rationale for the VCR values that we have applied in our forecasts and the risks of substituting a lower VCR value.

A further consideration in our planning is our obligation under the Victorian Electricity Distribution Code to meet our customers' reasonable expectations regarding reliability. We therefore weighed up what customers are telling us about their reliability requirements in forecasting our Augmentation capex. Section 15.3 explains the relationship between the VCR and our reliability targets under the STPIS.

As noted in Chapter 7, our customers have told us that they want the current level of reliability to be maintained. The VCR values we have used in forecasting our Augmentation capex are consistent with delivering the outcome sought by our customers. From this, it can be reasonably inferred that our customers support the VCR values we have used.

A particular issue of concern relates to our worst serviced customers. Service performance for these customers reflects existing capacity constraints. Deferral of Augmentation capex will therefore exacerbate service performance for customers that are already adversely affected.

We are incentivised by the regulatory arrangements to seek to minimise the total costs (including customer interruption costs) of delivering our Standard Control Services. Under the probabilistic planning approach, we identify a range of investment options, including non-network (demand-side or generation), network, or combinations of both, that could address the network limitations and maintain appropriate network reliability. Accordingly, network investment only proceeds where it is economically efficient having regard to credible variations in forecast maximum demand and other factors that may influence the timing of an augmentation. If an investment is identified as being the most economic to relieve the constraint then the project is entered into the forecast Augmentation works program for the required year.

Our bottom-up build of Augmentation works is then verified against a top-down approach, including using the AER's Augex model. We engaged Nuttall Consulting to independently populate and calibrate the AER's Augex model to validate our Augmentation capex forecast for the forthcoming regulatory period. Separate forecasts were developed for each of the main capex categories including sub-transmission lines, zone substations, high-voltage feeders and distribution system (substations and low voltage circuit). As noted in section 10.10.1, the Augex model is forecasting higher Augmentation capex for the forthcoming regulatory period compared to our forecast Augmentation capex.

10.10.3. Augmentation Justification

Our assessment is that a lower level of Augmentation capex will be required in the forthcoming regulatory period than we expect to spend in the current regulatory period. We have validated our forecast Augmentation capex to be lower than the AER's Augex model prediction for the forthcoming regulatory period. Full details of this validation are provided in the Nuttall Consulting Augex Modelling Report that we have provided with this Regulatory Proposal.

It is important to note that, in addition to providing the new capacity required to efficiently meet forecast maximum demand over the forthcoming period, our Augmentation capex proposal is an integral part of our overall plan to maintain reliability, as explained in sections 10.2.2 and 10.2.3. Under our capex proposal, the contribution made by Augmentation capex to reliability for the forthcoming regulatory period will be the same as it was for the current regulatory period. Our approach to VCR - explained in section 10.9 - is consistent with achieving this outcome.

More specifically, the key outcomes that we are seeking to achieve from our proposed Augmentation capex in the forthcoming regulatory period are:

- Maintaining reliability performance and expected unserved energy at present levels (i.e. no net improvement);

- Addressing reliability performance issues for our worst-served customers who are exposed to risk of long-duration outages on days of extreme temperature;
- Maintaining asset utilisation at present levels, while looking for economic opportunities that can increase asset utilisation without increasing overall expected unserved energy to customers;
- Reducing Augmentation capex particularly in the distribution system augmentation program by utilising our recent investments in AMI to provide more accurate information regarding distribution transformer and low voltage circuit utilisation;
- Interchanging capex with opex to fund economically prudent non-network opportunities identified through the RIT-D process and our joint-planning MoUs; and
- Migrating DMIA-funded trials to business-as-usual solutions to manage maximum demand when this is economically prudent to do so.

Our major Augmentation works for the forthcoming regulatory period are:

- Dromana second transformer and associated distribution feeders - $8.3 million in 2016-17;
- Notting Hill third transformer and associated distribution feeders - $5.8 million in 2017-18;
- Hastings-Rosebud new 66kV sub-transmission line - $23.2 million in 2018-19;
- Skye new zone substation and sub-transmission line - $23.4 million;
- Doncaster fourth transformer and associated sub-transmission line upgrades - $6.8 million in 2019-20;
- Mornington third transformer and associated distribution feeders - $7.6 million;
- Distribution system augmentation program to upgrade low voltage wires and transformers - $39.8 million over 2016 to 2020; and
- Feeder Augmentation / Pole Top Capacitor Programmes - $27.1 million over 2016 to 2020.

This Regulatory Proposal incorporates a range of innovative non-network solutions that can defer capex. In particular, we are committing $6.6 million (in DMIA opex) to demand-side management initiatives and $2.5 million (in Augmentation capex) to use storage ‘behind the meter’ as an alternative to network augmentation (i.e. a non-traditional investment). This investment of $2.5 million in storage will save $0.5 million by avoiding $3 million of traditional Augmentation capex in the forthcoming regulatory period.

Our Augmentation capex is explained in further detail in our Augmentation Overview document with economic evaluations undertaken for major projects and programs in our associated supporting documentation.

10.11. Connections capex

10.11.1. Overview

Connection projects involve establishing new connections or modifying or extending our existing distribution system to accommodate new customers’ demand. They are undertaken in accordance with our “UE Customer Connection Guide”.

All connections are initiated, and carried out, at the request of customers. The timing and level of connections is therefore largely outside of our control.

Connections are strongly correlated with the level of economic activity and, in particular, building and infrastructure developments. Most Connections capex is therefore based on econometric drivers.

We categorise our Connections capex as follows:

- Business supply projects;
- Urban multi-occupancy supply projects;

- Urban residential supply projects;
- Public lighting;
- Contestable metering new services;
- T5 public lighting;
- Recoverable works; and
- Rural supply projects.

We have mapped our Connections project categories to the AER's services classification to ensure that our capex is appropriately allocated for regulatory purposes.

Our forecast customer contributions are deducted from our (Gross) Connections capex to determine our Net Connections capex. In this way, our customer contributions are excluded from our Regulatory Asset Base for the purposes of determining our return on, and of, capital that is used to determine our Annual Revenue Requirements for Standard Control Services.

We therefore recover our customer contributions in addition to our Annual Revenue Requirements.

Because of our classification of services, it is necessary to prepare separate forecasts of our:

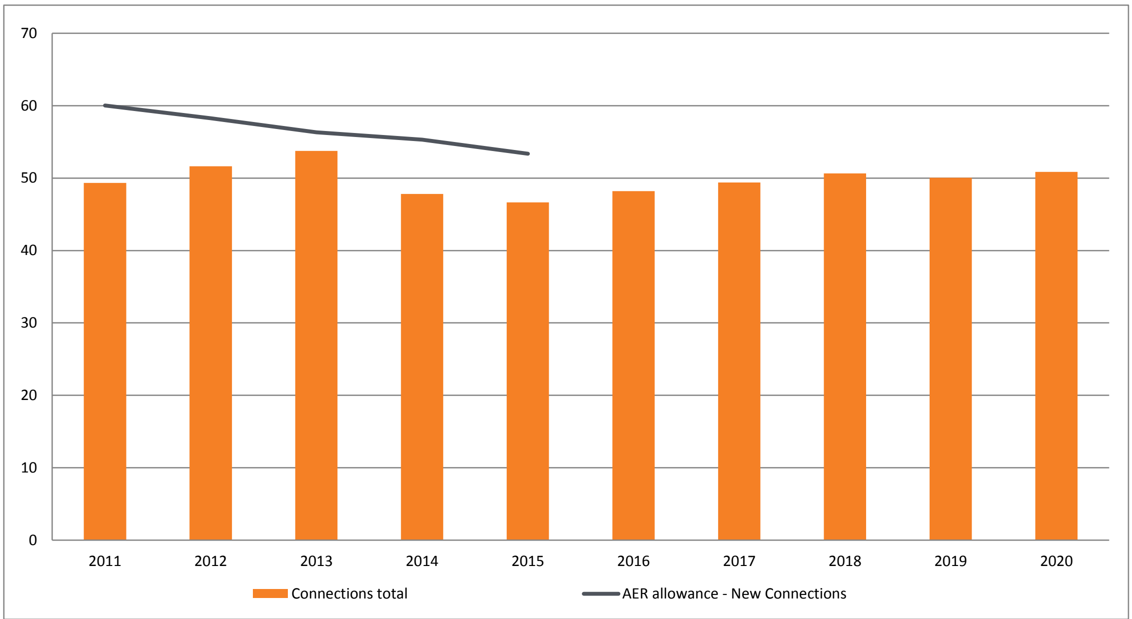
- (Gross) Connections capex; and
- Customer contributions;

for each of our:

- Standard Control Services;
- Alternative Control Services – Metering; and
- Negotiated Distribution Services – Public Lighting.

Figure 10-10 below shows our forecast Gross Connections capex for our Standard Control Services for the forthcoming regulatory period compared to our actual capex and the AER's allowance for the current period. In summary, we expect our Gross Connections capex in the forthcoming regulatory period to be approximately $249.1 million, which is the same as in the current period.

Figure 10-10 Historical and forecast Gross Connections capex ($M, Real 2015)



Some key points to note from Figure 10-10 are that:

- Actual Connections capex for 2011 to 2015 is within the AER's allowance – this is attributed to a consistent growth in population and customer numbers, and ongoing activities in the building construction industry; and
- Forecast Connections capex for 2016 to 2020 is marginally higher than our actual capex for 2011 to 2015 because of forecast growth in population and customer numbers, and ongoing activities in the building construction industry stimulated by low interest rates.

Further details are provided in our Connections Overview Paper.

Table 10-6 and Table 10-7 detail our forecast Gross Connections capex and customer contributions for the forthcoming regulatory period.

Table 10-6: Forecast Gross Connections capex 2016 – 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Gross Connections	48.2	49.3	50.6	50.1	50.9	249.1

Table 10-7: Forecast Customer Contributions 2016 – 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Connection contributions	17.7	18.1	18.3	18.7	18.5	91.4

10.11.2. Key inputs and drivers

We prepare our Gross Connections capex forecasts based on the following components:

- Volumes – we count the projects in the latest year and we apply our growth indices to these volumes;
- Growth indices – we apply indices that have been prepared by the Australian Construction Industry Forum (ACIF);
- Unit rates – we apply either (a) our standardised unit rates that we have contractually agreed with our service providers or (b) unit rates based on our average historical project cost;
- Expenditure profile – we determine monthly expenditure profiles using historical project data;
- Status of existing projects – we determine the status of our existing projects in the expenditure profile; and
- Initiation profile – we determine when the project starts in the year using historical project data.

We prepare our Gross Connections capex forecasts by applying different combinations of these components for what we refer to as our:

- Non-unitised projects – these are individually costed projects; and
- Unitised projects – the costs of these projects are forecast using standardised unit rates.

In addition to our Gross Connections capex, we forecast our customer contributions so that we can determine our Net Connections capex.

Our customer contributions comprise cash contributions and gifted assets.

We have prepared our cash contribution forecasts to be consistent with both the ESCV's Guideline 14 and the AER's national Customer Contributions Guidelines as we have updated our forecasting model for:

- The marginal cost of reinforcement (MCR) estimates to reflect current actual costs;
- An X factor of zero; and

- Opex so that it is excluded from both incremental revenue and incremental cost.

By applying these changes there are no material differences between the two Guidelines. Despite this, we strongly support the repeal of Guideline 14 and its replacement with the AER's Guidelines for the following reasons.

Currently, Guideline 14 requires that we include an allowance for incremental revenue in calculating a capital contribution for a connection offer. In estimating the incremental revenue, the Guideline requires that we assume that the X factor in the final year of the current Distribution Determination will apply over a 15 to 30 year study period (depending on the customer type). Accordingly, in the current regulatory period, we have needed to apply the AER's approved X factor for 2015 of -8.1 per cent per annum to our calculations of incremental revenue. This means that after 2015 we have effectively assumed that distribution tariffs will increase in real terms at a rate of 8.1 per cent per annum for more than 25 years in the case of domestic customers. In our view, this is unrealistic.

We estimate that we will receive about $80 million less in customer contributions over the current regulatory period than we forecast as a result of applying Guideline 14. The higher (net) Connections capex that we have directly incurred will be added to the Regulatory Asset Base and recovered from all customers.

The result of lower customer contributions has been that a greater proportion of the costs of Connections has been borne by all customers rather than by the individual customers requesting the service. In effect, this has resulted in a "wealth transfer" from all of our existing customers to developers (and other new customers) in the current period.

Put differently, the higher (and negative) X factor has artificially reduced capital contributions and has increased the Regulatory Asset Base, putting upward pressure on future tariffs.

We have written to the Victorian Government seeking an amendment to Guideline 14, as we see it is producing anomalous and unintended outcomes. This is because the purpose of the X factors, and the AER's approach to setting it under clause 6.5.9 of the Rules, are now different to when Guideline 14 was enacted.

Accordingly, in preparing our cash component of our customer contribution forecasts, we have assumed that the X factor will be zero. This will increase our upfront cash contributions but will reduce distribution use of system (DUOS) charges to existing customers.

10.11.3. Connections Justification

Our Connections capex is explained and justified in further detail in our "Connections Overview" document.

10.12. Replacement capex

10.12.1. Overview

Replacement capex is driven by our obligations under the Rules to:

- Maintain the quality, reliability and security of supply of standard control services;
- Maintain the reliability, safety and security of the distribution system; and
- Comply with all applicable regulatory obligations and requirements associated with the provision of standard control services.

Further details on these Replacement capex drivers are provided in section 10.12.2 below.

If inadequate Replacement capex is undertaken, our customers and the broader community will face an increasing exposure to:

- Deteriorating supply reliability due to an increase in the rate of asset failure;
- Deteriorating safety performance, putting at risk the health and wellbeing of our customers and staff;
- Increased bushfire risk; and
- Increased risk of environmental harm being caused by asset failure.

The underlying objective of our Replacement capex is to meet all of our reliability, safety and other compliance obligations in the most efficient manner. In practice, this means minimising the total life cycle costs by adopting an holistic prudent approach to our expenditure forecasting, recognising the contributions to be made from each expenditure category, including opex.

As noted in section 10.2.3 we have developed a prudent and efficient programme of Replacement capex that aims to address the deteriorating trend in network reliability, so that over the forthcoming regulatory period we can maintain reliability at the average level achieved over the course of the current regulatory period. In addition, our proposed Replacement capex program contains expenditure allowances for the investment we need to undertake to ensure that all of our compliance obligations are met.

Turning specifically to reliability, Replacement capex plays a key role in achieving our reliability target in the forthcoming regulatory period. As already noted, our network is exhibiting a deteriorating trend in reliability performance, driven principally by an ageing asset base and increased incidence of equipment failure. Consequently, there is a significant gap between current unplanned SAIDI of 78 minutes and the target for the forthcoming regulatory period, which is based on historical average performance over the previous five years.

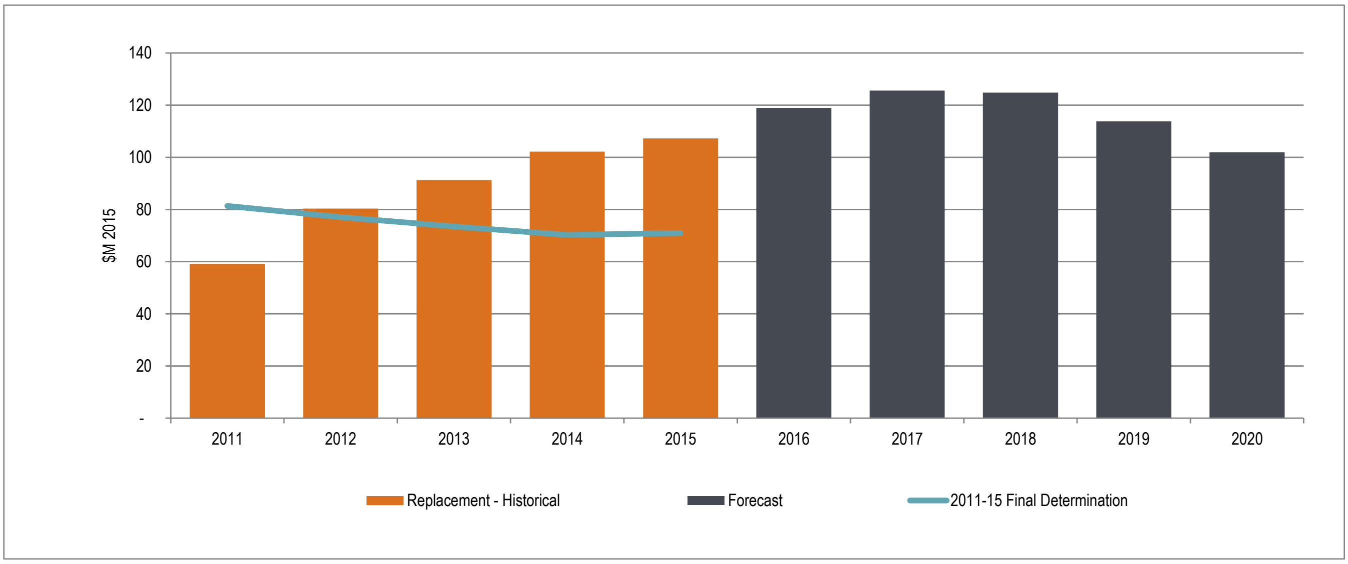
Table 10-8 shows our forecast Replacement capex for the forthcoming regulatory period, and includes non-ICT field-based capex on Network Control and Protection.

Table 10-8: Forecast replacement capex 2016 – 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Replacement	118.9	125.6	124.8	113.8	101.9	585.1

Figure 10-11 shows our actual Replacement capex for the current regulatory period alongside our forecast for the forthcoming period. The categorisation of expenditure across both periods is consistent.

Figure 10-11: Historical and forecast Replacement capex ($m, Real 2015)



It should be noted from Figure 10-11 that:

- Actual Replacement capex for 2011 to 2015 exceeded the AER's allowance, as we responded to deteriorating reliability performance against a backdrop of increasing replacement costs; and
- In aggregate terms, our forecast Replacement capex will increase by $144.5 million or approximately 33 per cent over the forthcoming regulatory period compared to our actual capex in the current regulatory period. As explained in detail in this Regulatory Proposal, this capex is required in order to enable us to meet all of our

regulatory compliance obligations relating to quality, safety, security and reliability, and to deliver a level of network reliability that maintains the average level achieved over the current period.

Table 10-9 shows our forecast Replacement capex for the forthcoming regulatory period, presented in the following groups:

- Replacement – Modelled and within scope of Repex model. This group matches the scope of the work that is covered by the AER's Repex model, and includes end-of-life asset replacement;
- Replacement – Modelled but outside scope of Repex model. This group contains capital works that are outside the scope of the AER's Repex model. Replacement expenditure in this group includes public lighting, field network control and protection and zone substation Primary Assets capex;
- Replacement unmodelled – This group contains capex that is excluded from the AER Repex model. The expenditure in this group relates to capex that is undertaken for reasons other than end-of-life asset replacement. The principal driver of capex in this group is safety. The two largest components of this expenditure are SWER replacement for bushfire mitigation and replacement of Doncaster pillars to safeguard the public from electrocution; and
- Other – This group includes network performance capex (on items such as Automatic Circuit Reclosers and Remote Control Gas Switches and animal proofing); environmental compliance capex, safety capex (on assets such as REFCLs), power quality, and operational technology investment required to ensure safety and maintenance of reliability.

Table 10-9: Forecast replacement capex 2016 – 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Replacement - Modelled and within scope of repex model	66.7	76.7	78.8	76.8	66.9	**366.0**
Replacement - Modelled (PL, SCADA & ZSS other) outside scope of repex model	9.3	8.6	6.9	5.6	6.6	**37.0**
Replacement – Un-modelled	9.6	11.9	13.4	10.5	8.1	**53.5**
Replacement - Other	32.0	24.9	20.6	17.4	17.4	**112.3**
Replacement -Total (pre-escalation)	**117.6**	**122.2**	**119.7**	**110.3**	**99.0**	**568.9**
Weighted average escalator	1.3	3.5	5.1	3.5	2.9	**16.2**
Replacement -Total (escalated)	**118.9**	**125.6**	**124.8**	**113.8**	**101.9**	**585.1**

Figure 10-12 shows the above data in graphical form, along with actual Replacement capex for the current regulatory period.

Figure 10-12: Actual and forecast replacement capex 2011 – 2020 ($M, Real 2015)

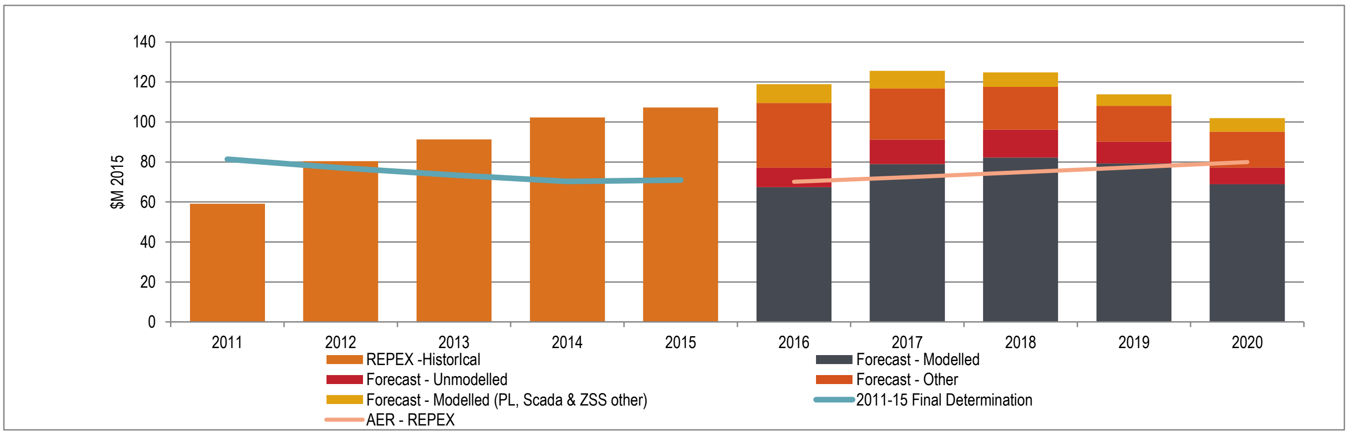


Figure 10-12 also shows the upper-bound of Nuttall Consulting's Repex modelling (using the AER's Repex Model) against our Replacement capex (modelled component).

We note the following points in relation to Figure 10-12:

- Nuttall Consulting's Repex modelling only covers the modelled component of Replacement capex – this is consistent with the AER's approach and represents about 64 per cent of our total unescalated Replacement capex;
- Nuttall Consulting's Repex modelling presents several scenarios and therefore identifies an upper and lower reasonable range of Replacement capex (modelled component). We think the best scenario is the one that uses our 2013-14 unit rates because they are the most current, market-tested rates that are available;
- Nuttall Consulting's assessment of the reasonable range of the Replacement capex (modelled component) shows a steadily rising replacement program over time;
- Our forecast of the Replacement capex (modelled component) falls below the best scenario in the Repex model as modelled by Nuttall Consulting, which has been calculated using our 2013-14 unit rates;
- Our current performance data is indicating higher asset failure rates which are not fully reflected in the Repex model across certain asset categories, namely pole top structures, transformers, switchgear and overhead conductors. This will cause the AER's Repex model to under-estimate our efficient Replacement capex requirements; and
- Our forecast capex on replacement of services includes expected asset failures attributable to causes other than age. Examples include third party damage. The AER's Repex model, on the other hand, is based on relatively young average asset age with a bias towards lower replacement volumes. This will cause the AER's Repex model to under-estimate efficient Replacement capex.

The efficiency of our Replacement capex (modelled component) would be further enhanced if these last two matters are taken into account in reviewing the outcomes of the AER's Repex model.

10.12.2. Key inputs and drivers

As noted in section 10.12.1, our Replacement capex must enable us to meet our compliance obligations. It is useful, therefore, to summarise the compliance obligations that are most relevant to our Replacement capex.

Clause 3.1 of the Victorian Electricity Distribution Code (the Code) requires us to manage our assets in accordance with the principles of good asset management. Under this provision, we must, among other things, develop and implement plans for the acquisition, creation, maintenance, operation, refurbishment, repair and disposal of our distribution system assets:

- To comply with the laws and other performance obligations which apply to the provision of distribution services including those contained in the Distribution Code;

- To minimise the risks associated with the failure or reduced performance of assets; and
- In a way that minimises costs to customers, taking into account distribution losses.

Under clause 5.2 of the Code, we are required to use best endeavours to meet customers' reasonable expectations of supply reliability.

Clause 4.2 of the Code requires voltages to be maintained within specified limits. It also sets out requirements relating to monitoring of voltages and voltage variations. Chapter 4 of the Rules sets out requirements relating to power system security with which we must comply.

Under section 98 of the *Electricity Safety Act 1998*, we must design, construct, operate, maintain and decommission our supply network to minimise as far as practicable:

- The hazards and risks to the safety of any person arising from the supply network;
- The hazards and risks of damage to the property of any person arising from the supply network; and
- The bushfire danger arising from the supply network.

Our Replacement capex forecast reflects the efficient level of capex we need to ensure that we manage network safety in accordance with the requirements of the *Electricity Safety Act 1998*.

In addition, we must frame our Replacement capex forecast in light of the requirements of various regulations issued by the Environment Protection Authority. Our Environment Strategy and Plan document UE PL 2038 details our approach to ensuring compliance, and our Replacement capex forecasts reflect the capex requirements driven by these compliance requirements.

In summary, the compliance obligations noted above are important inputs to our Replacement capex plans. We must aim to satisfy all of these obligations. As already noted in section 10.12.1, these obligations, together with reliability considerations, are the key drivers of our Replacement capex requirements.

In terms of network reliability specifically, we explained in section 10.2.2 that reliability is a key performance issue that we must address in the forthcoming regulatory period. We expect the AER will set an unplanned SAIDI target of approximately 68 minutes in the forthcoming regulatory period, reflecting our average performance over the previous five years. However, our actual performance has followed a deteriorating trend, resulting in unplanned SAIDI of 78 minutes in 2014. Our Replacement capex proposal will enable us to meet an unplanned SAIDI target of 68 minutes in the forthcoming period, consistent with our obligations to maintain network reliability.

As already noted, the age profile of our assets is an unavoidable consequence of the substantial growth in network investment in the 1960s and 1970s. Asset condition and performance are prone to rapid deterioration as assets age, which exposes customers to reliability risks. Figure 10-13 shows the increasing proportion of our asset base consisting of assets that have less than 15 per cent of expected life remaining.

Figure 10-13: Trend of assets approaching end-of life

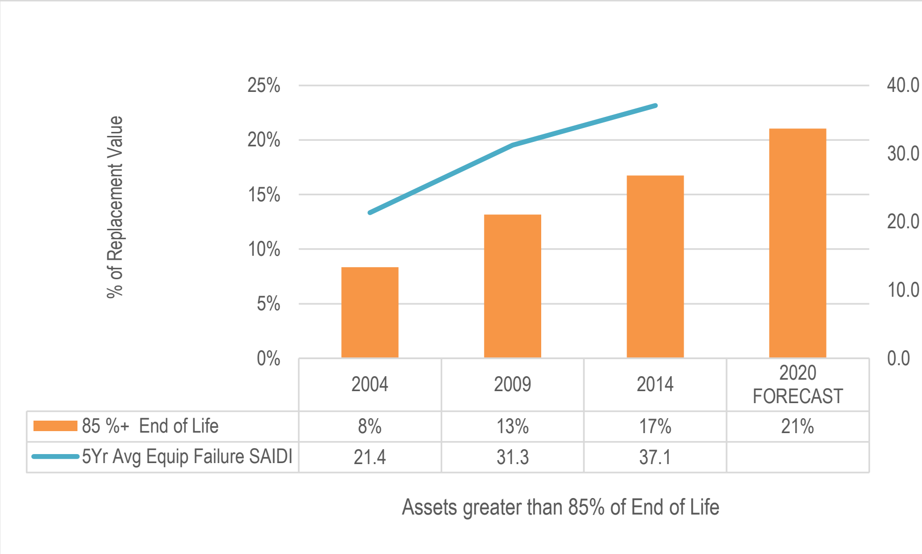
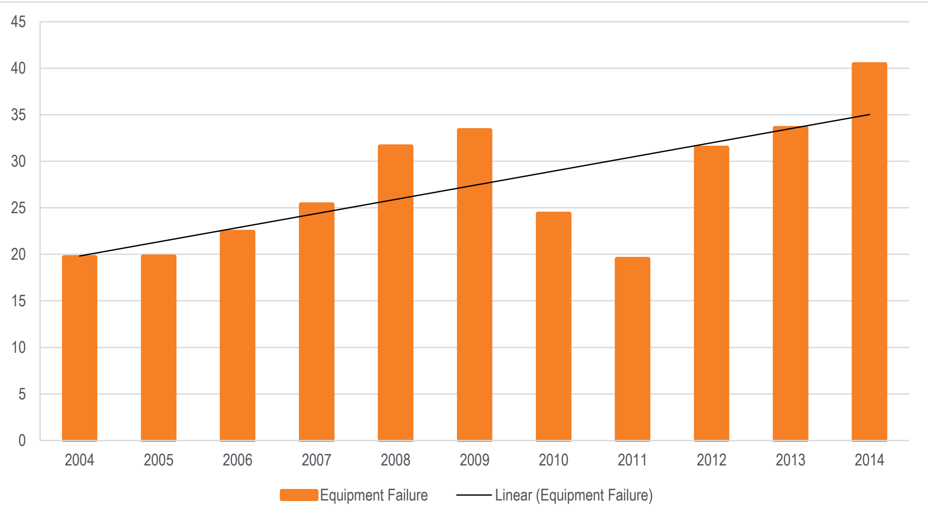


Figure 10-14 shows that the increasing proportion of assets nearing the end-of-life is closely correlated with the deteriorating trend in our network reliability. The figure below shows that our network reliability is exhibiting a trend deterioration of 1.5 minutes per annum due to equipment failure.

Figure 10-14: Actual and trend unplanned SAIDI due to equipment failure (minutes)



As noted in section 10.2.3, we have adopted a prudent and efficient approach to maintaining reliability, and this approach underpins our Replacement capex forecast. In particular:

- Replacement capex is the primary expenditure category (but not the only category) that will make a contribution to maintaining reliability;
- Replacing assets at their end of life is the largest component of our Replacement capex forecast (as represented by “Replacement – Modelled and within scope of repex model” group of expenditure referred to in section 10.12.1); and
- Our approach to Replacement capex ensures that we find the most cost effective means of delivering the SAIDI target set by the AER.

Specifically, we have set our Replacement capex forecast at a level that allows more equipment to progress to the age where it has under 15 per cent of expected asset life remaining. However, we mitigate the risk of equipment failure through targeted programs and initiatives, through our proposed network performance capex, operational technology capex, and ICT capex. This approach enables us to maintain reliability in a more cost effective manner than could be achieved by replacing more assets at end of life.

Our forecast Replacement capex is underpinned by our LCS for each asset class. Together, these strategies address the increasing trend in asset failures and the deteriorating trend in network reliability. The objective of each LCS is to minimise total life cycle costs by optimising the maintenance and Replacement capex program. This objective is achieved by balancing the costs of increasing expenditure against the risks and consequences of asset failure. Each LCS considers a number of options for managing the asset class, including capex programs to address specific issues, before selecting the preferred approach.

More specifically, to address our deteriorating reliability performance, we have introduced a number of programs within various LCS including:

- Improving inspection regimes through the use of new technologies, such as pole top cameras and partial discharge tests to better understand what assets are at their end of life;
- Improving forecasts using Weibull models and Condition Based Risk Models to forecast asset replacement; and
- Targeting programs to address poor performing assets such as HV Aerial Bundled Cable.

These improvement programs enable us to achieve better outcomes for a given level of Replacement capex. For example, in the forthcoming regulatory period we plan to reduce SAIDI from pole top structures for a slightly lower level of Replacement capex. This outcome can only be achieved by investing in new processes – such as the of use pole top cameras – to support Replacement capex and improve its effectiveness.

While we forecast reductions in Replacement capex for some asset categories, expenditure for other assets must increase in order to address the growing risk of equipment failure. For example, our condition monitoring shows that 17 zone substation transformers are approaching the end of their lives (compared to four in the current period), and must be replaced in the forthcoming period. While the contribution to unplanned SAIDI from zone substation transformers is currently very low, this positive situation will not continue unless Replacement capex for this critical asset class increases.

It should also be noted that our forecast Replacement capex includes a number of safety programs which are forecast to cost approximately $27 million in total over the forthcoming regulatory period. The main safety initiatives include:

- Replacement of Doncaster pillars;
- Installation of REFCLs in four zone substations to reduce the risk of fire from conductor failures in high bushfire risk areas;
- Installation of CCTV at four zone substations per annum; and
- Removal of SWER power lines, as recommended by the VBRC.

In addition, our Replacement capex forecast includes approximately $13 million on compliance relating to the environment and power quality.

Whilst our approach to Replacement capex ensures that we find the most cost effective means of delivering our obligations, in aggregate, Replacement capex must increase in the forthcoming regulatory period to achieve the target outcomes.

10.12.3. Replacement Capex Justification

To recap, the main underlying drivers of our Replacement capex are:

- Our requirements to comply with mandatory regulatory obligations relating to safety, health, environmental protection, technical performance, supply reliability and asset management;

- The age profile of our assets, which is an unavoidable consequence of the substantial growth in network investment during the 1960s and 1970s; and
- The exposure of our customers to reliability risks associated with an ageing asset base, given that asset condition and network reliability performance are prone to deterioration as assets age.

We manage our assets in accordance with LCS, which aim to minimise the total life cycle costs by optimising our maintenance and Replacement capex programs, having regard to the trade-off between risk and cost.

Our expenditure plans must enable us to satisfy our compliance obligations. In accordance with the requirements of clause 6.5.7(a) of the Rules, our proposed Replacement capex for the forthcoming regulatory period ensures that we achieve the following objectives:

- Meet or manage the expected demand for standard control services over that period;
- Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services; and
- Maintain the quality, reliability, security and safety of standard control services and our distribution network.

A key challenge in the forthcoming regulatory period is to arrest the trend decline in reliability performance. Our 2014 SAIDI is significantly higher than the AER's target for the forthcoming regulatory period. Our customers expect us to maintain performance, which means returning future SAIDI performance to the target level, which reflects the historical average over the previous five years. Our capex plans are focused on delivering this outcome and managing the emerging network risk associated with an ageing asset base, which unavoidably leads to increased risk of asset failure.

We are also looking for smarter ways of delivering the required outcomes with fewer inputs. For example, we are investing in technology that allows us to anticipate asset failures and respond to major outage events more effectively. Our Replacement capex plans depend on the support from new technology to deliver the required reliability outcomes. In the absence of this support, substantially more Replacement capex would be required to deliver the same outcome.

In addition to the material presented in this Regulatory Proposal, we provide further detailed justification of the Replacement capex in the Replacement Capex Overview document and Category Expenditure Explanatory Statements for each of the AER's Replacement RIN categories.

This further detailed information is underpinned by asset strategies detailed in our LCS and network strategies. These supporting documents collectively demonstrate that our forecast capex satisfies the capex criteria in clause 6.5.7(c) of the Rules.

10.13. Non-network IT and Communications capex

10.13.1. Overview

This capex category includes all areas of ICT capex, including corporate applications, asset management, network management, works management and revenue management applications as well as ICT infrastructure and facilities that we require to provide our Standard Control Services. It includes capex on central elements of SCADA and network control systems.

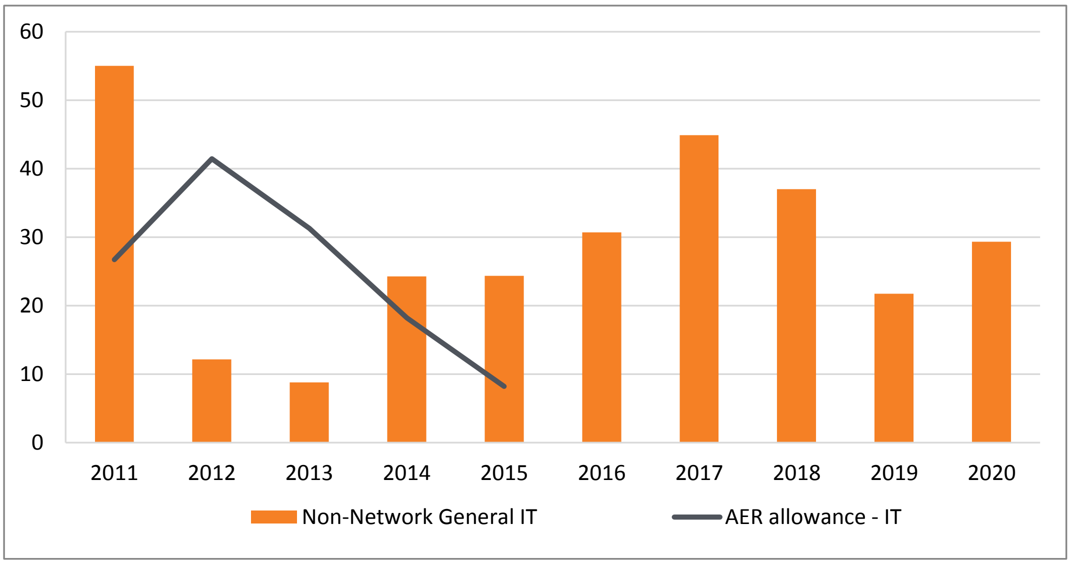
Table 10-10 below shows the forecast non-network capex associated with the delivery of Standard Control Services for the forthcoming regulatory period.

Table 10-10: Forecast non-network ICT capex 2016 - 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Non-Network General Assets – ICT	30.7	44.9	37.0	21.7	29.3	163.7

Figure 10-15 details the trend in our ICT capex over the period 2011 to 2020.

Figure 10-15: Historical and forecast non-network ICT capex ($M, Real 2015)



The following observations are noted in relation to our actual and forecast ICT capex:

- Our ICT capex in the current regulatory period will be slightly above the AER's allowance. In this period, we have successfully delivered a challenging ICT capex program, including several large ICT projects that were critical to our business transformation. We implemented a major ERP replacement project, a system separation project, two data centre relocations, a major infrastructure refresh, updates of the distribution management system and upgrades of market systems;
- The scope of the ICT program and the projects completed were closely aligned to the ICT Capital Plan presented to the AER five years ago. Where changes and reprioritisations to the program were necessary, these were managed through a robust ICT governance structure; and
- The ICT systems implemented in the current regulatory period provide a sound foundation for the delivery of further projects in the forthcoming regulatory period. The focus on robust governance of ICT projects will continue.

Further detailed information on our ICT capex forecasts is set out below.

10.13.2. Key inputs and drivers

Our ICT systems are an integral part of our business operations. Continued investment in ICT in the forthcoming regulatory period is essential to maintain our systems at industry standard. Without on-going investment to maintain and refresh our ICT assets, we will not be able to continue to achieve the required system availability and performance levels required by customers, or to meet future industry and regulatory challenges.

The functions supported by our ICT systems are outlined in Table 10-11.

Table 10-11: Functions supported by ICT systems

Function	Explanation
Customer and Stakeholder Management	Provision of services and/or information to internal and external stakeholders (including customers, retailers, government agencies, regulators, partners and employees).
Network Management	Management, monitoring and control of the distribution network including responding to faults/emergencies, and analysis and optimisation of the network.
Asset Management	Strategic planning and management of assets, work programs and resources, including network extensions, inspections, maintenance and construction.
ICT Management	ICT capabilities enabling operations and supporting planning and management of the business, including managing applications, ICT portfolio, infrastructure, architecture, security and ICT services.
Works Management	Management of work programs and resources for network extensions, inspections, maintenance and construction.
Meter Data and Revenue Management	Management of meter data, connection points and meter services, including the provision of data to market and management of service orders and metering faults.
Information Management	Capabilities required to effectively manage large amounts of structured and unstructured information across the business.
Business Support Management	Corporate capabilities required to support the business including finance, HR, risk & audit, legal, supply chain & logistics and OH&S.

Our forecast ICT capex for Standard Control Services for the forthcoming regulatory period is $163.7 million. This excludes ICT capex costs associated with the delivery of Metering Alternative Control Services (details of which are presented in Chapter 18).

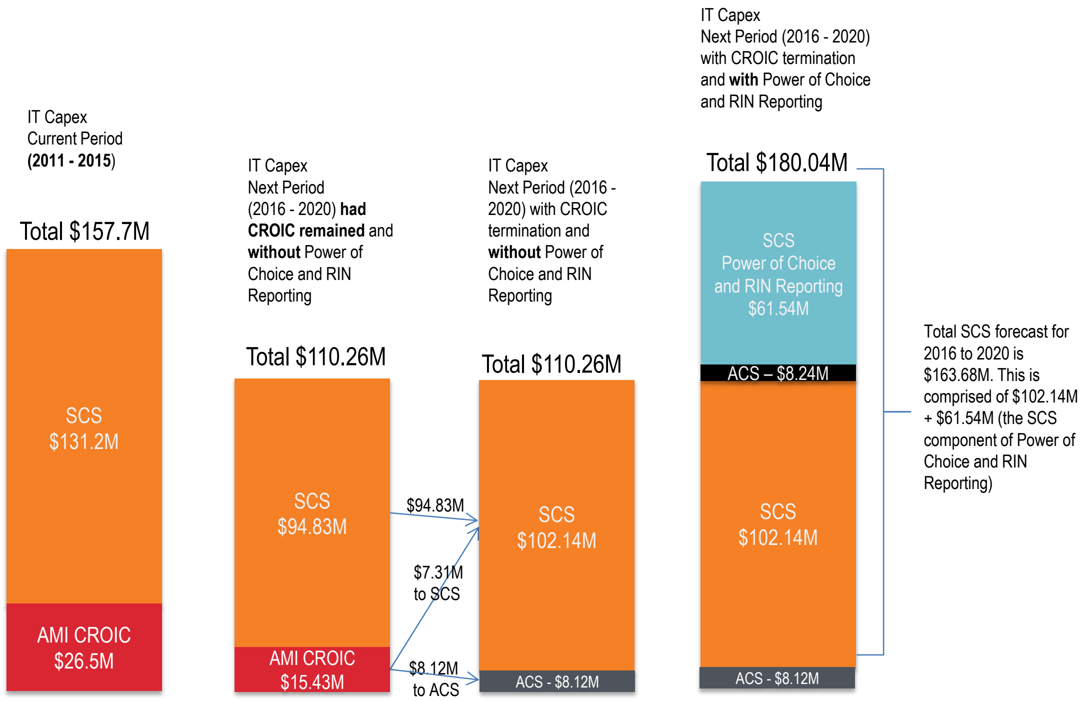
Three factors need to be considered when comparing this forecast to the actual ICT capex in the current regulatory period:

- The Rules' changes being introduced by the AEMC under the Power of Choice reforms will require significant ICT capex in the forthcoming regulatory period. This required capex has been included in our forecasts;
- The AER's new RIN reporting requirements also require significant ICT capex in the forthcoming regulatory period. This required capex has been included in our forecasts; and
- ICT capex of $7 million will be required in the forthcoming regulatory period to maintain those systems that were implemented or modified under the Victorian Government's AMI CROIC and that are required for the provision of Standard Control Services. Expenditure on these systems is currently recovered through the cost-recovery regime established by the CROIC. As economic regulation under the CROIC ends on 31 December 2015, some of these costs, which would have been recovered under the CROIC had it continued, will now be included in the Standard Control Services expenditure in the forthcoming regulatory period.

A simple comparison of our Standard Control Services Non-Network ICT capex between the current and forthcoming regulatory periods would not take into account these three factors. Accurately comparing costs between the two periods requires excluding the costs for Power of Choice and RIN Reporting and taking into account the costs that would have been recovered under the CROIC had it continued. On this like-for-like basis, our ICT capex in the forthcoming regulatory period would have reduced by $61.5 million, or approximately 38 per cent, had we not been required to meet the additional requirements of Power of Choice and RIN reporting.

The figure below provides a comparison of our actual and forecast ICT capex for the current and forthcoming regulatory periods.

Figure 10-16: Comparison of ICT capex for current and future regulatory period



Our forecast for non-network ICT capex reflects the key drivers and inputs already described. We have planned a program of ICT projects that will:

- Deliver new capability to meet changing customer needs and growing expectations. We will implement ICT solutions that address the needs and expectations of customers by providing services and information via web-based and mobile communication channels and leveraging our AMI systems to increase the accuracy of notifications about outages;
- Improve AMS capability to enable better asset management decisions, primarily to better target asset replacement capex. Our projects include the AMS Capability Project and the RIN Reporting and Asset Data Collection projects. These projects will provide the revised data structures to capture the necessary data, populate the structures with data, and setup systems (mobility) to keep the data up to date. The efficient targeting of Replacement capex relies on this enhanced capability.
- Maintain network reliability, as ICT is part of our holistic reliability management approach explained in section 10.2.3. Although the AMS capability above will primarily result in benefits being realised after 2020 (due to the scheduling of the relevant ICT projects), several other ICT projects for the forthcoming regulatory period facilitate faster supply restoration. Some projects provide better information on unplanned outages, and others allow faster decisions around reconfiguring the network;
- Achieve compliance, mostly relating to safety. The network analytics drawing on AMI data have many safety benefits, including neutral integrity testing; and a range of smart detection of faults, which are safety hazards (such as wires down); and
- Maintain systems to industry standard to avoid increased risk of disruption to customers and to retain levels of efficiency. Having completed a major overhaul of our ICT systems in recent years, we will continue to invest in the systems to ensure that these systems are refreshed to maintain the industry standard required to meet the needs of our customers.

The proposed ICT capital program will enable us to meet the needs of our customers by maintaining systems at industry standard, addressing current gaps in functionality, meeting regulatory requirements and addressing future business challenges and opportunities.

Our ICT capex is explained in further detail in our ICT Capex Overview document.

10.14. Non-network General capex

10.14.1. Overview

This capex category is critical to supporting our network and corporate functions. This category is subdivided into the following components, which are our "business-as-usual" expenditure categories:

- Operational property, which relates to land for depots and substations;
- Office accommodation and fit out;
- Fleet, which is required to construct, repair and maintain our network; and
- Miscellaneous tools and equipment to construct, repair and maintain our network.

The figure below shows our forecast Non-Network General capex for our Standard Control Services for the forthcoming regulatory period compared to our actual capex and the AER's allowance for the current period. In summary, we expect our Non-Network General capex to average $6.2 million per annum, which is 20 per cent less than we incurred in the current period.

Figure 10-17 Historical and forecast Non-Network General capex ($M, Real 2015)

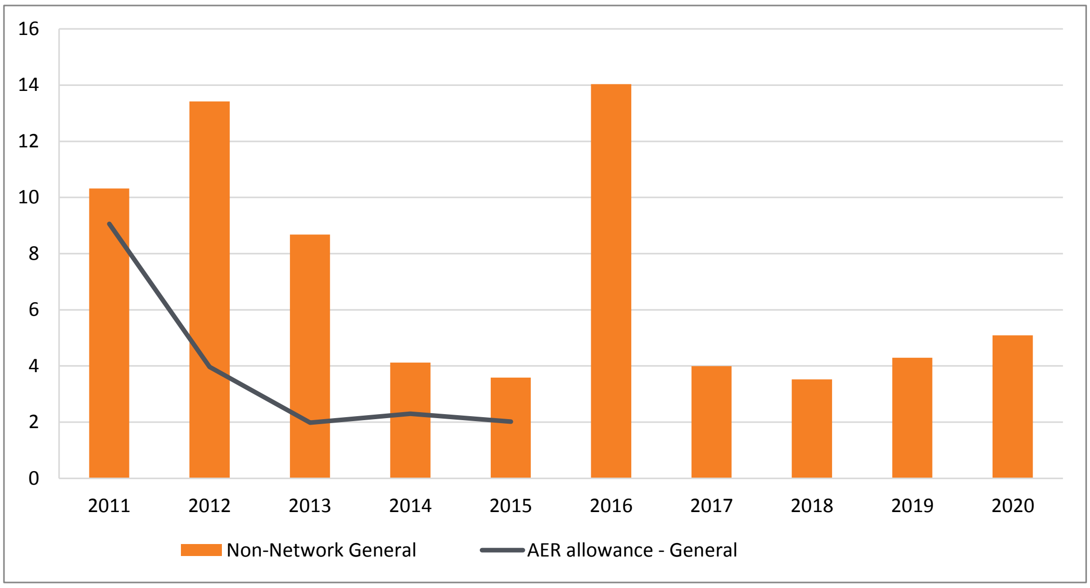


Table 10-12 below details our Non-Network General capex for our Standard Control Services forecast for the forthcoming regulatory period.

Table 10-12: Forecast Non-Network General capex 2016 – 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Operational property	2.5	0.3	0.3	0.3	1.5	**5.0**
Office accommodation and fit-out	4.9	0.1	0.1	0.0	0.1	**5.3**
Fleet	6.0	3.0	2.6	3.5	3.2	**18.3**
Miscellaneous tools and equipment	0.6	0.6	0.6	0.4	0.3	**2.4**
Total	**14.0**	**4.0**	**3.5**	**4.3**	**5.1**	**30.9**

As explained below, $10.2 million of the apparent spike in expenditure in 2016 is due to “lumpy” one-off capex on the acquisition of a zone substation site ($2 million), fit-out of office accommodation at Pinewood ($4.9 million) and additional investment ($6.6 million over the period, including $3.3 million in 2016) to increase our level of fleet ownership to 85 per cent of total requirements.

10.14.2. Key inputs and drivers

Operational property

A total of $3 million of the $5 million of operational property capex forecast relates to the acquisition of two zone substation sites. A site at Skye is to be acquired (for $2 million) in 2016, while an allowance of $1 million (being 50 per cent of the cost of acquiring land at Scoresby) is included in 2020. The remaining $2 million of forecast expenditure relates to depots, including:

- Miscellaneous minor capital works at each of our depots; and
- Cleaning up a site at Dandenong to make it suitable for storage of inventory.

Office accommodation and fit out

The key driver of office accommodation capex in the current regulatory period has been the need to accommodate the significant increase in internal staff and contractors following the implementation of our new business model. Our forecast is based on the current and projected employee head-count, and the depreciation profile of existing furniture and fittings. Floor space requirements are determined in accordance with industry benchmark standards. These standards reflect relevant occupational health and safety requirements.

Our expenditure forecasts for office accommodation include the costs of further consolidation of office-based staff at Pinewood, noting the following benefits:

- It is the most cost-effective solution over the long-term;
- The space available allows for future growth, giving us flexibility to manage uncertainty;
- It leverages our already sizeable investment in the Pinewood site; and
- It enables the co-location of staff, enhancing our efficiency and our ability to continue to strengthen a customer-focused culture.

We expect to incur $4.9 million of office accommodation and fit-out capex in 2016, reflecting the completion of our consolidated office accommodation at Pinewood in that year.

Fleet

We have a policy of making fleet resources available to our external service providers on a “free issue” basis. Not only is this approach consistent with minimising our fleet costs, it also creates additional flexibility to engage alternative service providers, thus exposing our current service providers to increased competitive pressure.

In accordance with our strategy, our total free issue fleet with service providers has increased from 108 vehicles in January 2011 to 174 as of July 2014. We have subsequently determined that the free issue fleet for both the Northern and Southern service providers should be of sufficient size to allow a new service provider to commence work should an incumbent service provider need to be replaced or become uncompetitive.

Our total fleet capex forecast ($18.25 million) comprises:

- $6.6 million of additional investment required to implement our strategy of owning 85 per cent of the required fleet; plus
- $11.6 million of capex associated with economic replacement of the existing fleet.

Miscellaneous tools and equipment

We forecast total capex of $2.44 million on tools and equipment over the forthcoming regulatory period. Allowing for the increase in our fleet ownership (explained above), this is consistent with our actual level of investment in the current regulatory period.

Further information on Non-Network General capex is provided in the supporting Overview document. This document provides a more detailed explanation of our forecasts, including a demonstration of compliance with the capex objectives in the Rules.

11. Opex forecasts

Key messages:

- We benchmark favourably against our peers. The AER's benchmarking, and the independent benchmarking that we have commissioned, show that our historical opex is efficient and that we are operating at or very close to the efficient frontier of DNSPs in the NEM. We are the most efficient DNSP in the NEM if capitalised overheads are included in all DNSPs' opex.
- We have structured our opex forecasts to maintain the quality, reliability and security of supply of our Standard Control Services to our customers.
- We propose increasing our total opex by $158 million, or 25 per cent, in the forthcoming regulatory period. This increase is largely due to an adjustment to our 2014 opex base year for opex attributable to our AMI (currently regulated under the CROIC) that will be regulated as Standard Control Services in the forthcoming regulatory period. This increases our base year opex by $19 million.
- We have applied a base-step-trend (BST) forecasting methodology to prepare our opex forecast. This is the AER's preferred forecasting method and is the approach we proposed in our Expenditure Forecasting Methodology submission in May 2014.
- Our 2014 opex provides an efficient base year for our opex forecast. There is no need for the AER to make any adjustments (over and above those that we have proposed) to our base year opex.
- We applied labour cost escalators prepared by independent experts, BIS Shrapnel, to our mix of employees and contractors to forecast a real labour cost increase of $7 million over the forthcoming regulatory period.
- We included an allowance of $8.1 million in our opex forecast over the regulatory period for the impact of output growth – as measured by customer numbers, circuit length and ratcheted maximum demand. This reflects the fact that greater output costs us more to operate and maintain.
- We included a range of step changes in our opex forecast to account for additional costs in the forthcoming regulatory period that we did not incur in our base year opex. We have grouped these step changes as follows:
  - New regulatory obligations – these have an annual opex impact;
  - Existing regulatory obligations – these are recurrent in nature but do not have a non-annual opex impact;
  - Customer response / initiated – the impact of these is specific to the step-change;
  - Changes in external environment – these have an annual opex impact;
  - New application of the Rules – these have an on-going opex impact; and
  - Capex – opex trade-offs – these also have an on-going opex impact.

11.1. Introduction

Our opex is the operating, maintenance and other non-capex that we incur to provide our distribution services to our customers.

This chapter explains and justifies our opex forecast for our Standard Control Services for the forthcoming regulatory period. Our opex forecasts must comply with the Rules' requirements. Broadly, the Rules require us to submit an efficient opex forecast that is consistent with maintaining the quality, reliability and safety of the network and network services. As explained in section 10.1, these objectives are underpinned by the Victorian Electricity Distribution Code[12] and our customers' reasonable expectations that we should maintain supply reliability.

[12] Clause 5.2.

We have used a BST approach to prepare our opex forecast for the forthcoming regulatory period, the build-up of which is set out in Table 11-1. Our opex forecasts include only operating expenditure that is properly allocated to standard control services in accordance with the principles and policies set out in our Cost Allocation Method.

Table 11-1: Forecast opex – Standard Control Services ($M, Real 2015) *

	2016	2017	2018	2019	2020	TOTAL
Base	124.8	124.8	124.8	124.8	124.8	623.9
Base Year Adjustments	16.3	16.3	16.3	16.3	16.3	81.6
Output Growth	1.2	1.5	2.1	1.7	1.6	8.1
Price Growth	0.8	1.1	1.6	1.9	1.6	7.0
Productivity Growth	0.0	0.0	0.0	0.0	0.0	0.0
Step Changes	8.7	10.3	10.0	12.9	11.9	53.8
Guaranteed Service Levels	1.1	1.1	1.1	1.1	1.1	5.7
DMIS	2.4	1.3	1.1	1.1	0.8	6.6
Debt raising costs	2.5	2.6	2.7	2.9	3.0	13.7
Total	**157.7**	**159.1**	**159.9**	**162.6**	**161.1**	**800.4**

* Excludes shared assets and Efficiency Carryover Mechanism

It should be noted that the information presented in this chapter is intentionally 'high level' to enable the AER, our customers and other stakeholders to understand readily our opex forecasts and the principal causes of the proposed increase. Our "Operating Expenditure Overview" document that we have provided to the AER with this Regulatory Proposal provides a detailed substantiation of our opex forecasts. Stakeholders that are seeking a more detailed explanation of our forecasts should refer to that document.

11.2. Our historical opex

Table 11-2 details our actual and estimated opex for the previous and current regulatory periods.

Table 11-2: Previous and current period opex – Standard Control Services ($M, Real 2015)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015*
Distribution Determination	108.8	111.1	113.4	115.9	115.6	120.2	122.6	123.3	128.1	129.8
Actual / Estimated (including provisions)	106.3	100.1	103.0	102.3	109.1	134.6	134.9	121.4	125.6	126.3
Variance (Actual – Determination)	(2.6)	(11.0)	(10.4)	(13.6)	(6.5)	14.5	12.3	(1.9)	(2.5)	(3.4)

* = Estimated

Table 11-2 shows that in the previous regulatory period, 2006 to 2010:

- Our actual opex was in a stable band between $100.1 million and $109.1 million per annum. This reflected the stability delivered by our contractual arrangements; and

- We consistently underspent against the ESCV's opex allowance – in total by $44 million over the regulatory period. This reflected the fact that we continually responded to the regulatory incentives provided by the ESCV.

We are expecting to overspend the AER's determination in the current regulatory period by about $19 million.

We had a significant step-up in our opex between 2010 and 2011. This was attributable to:

- A range of step changes that the AER approved in its Distribution Determination for the current regulatory period. These total $10.6 million and related to: Electricity Safety (Electric Line Clearance) Regulations; Electricity Safety (Bushfire Mitigation) Regulations—Private Overhead Electric Lines; Environmental Protection (Industrial Waste Resource) Regulations—Consultant Studies; National Framework for distribution network planning and expansion; Customer charter; Customer communications; Rectify steady state voltage violations; ZS power quality metering maintenance; ZS secondary spares maintenance; Energy Safe Victoria levy; and
- Our internal business transformation project of $15 million. This was foreshadowed in our Regulatory Proposal and Revised Regulatory Proposal but was not accepted by the AER in its Distribution Determination. The costs involved implementing new business processes and systems and meeting the costs of redundancies associated with gaining efficiencies, in order to deliver greater cost reductions going forward, when compared with a projection of costs under the former business model.

As our opex for 2011 and 2012 was above the AER's approved allowance, we funded the overspend ourselves and its effect flows through to the benefit of customers under the AER's Efficiency Benefit Sharing Scheme (EBSS) through the Efficiency Carryover Mechanism. Because this overspend occurred early in the period – not in the penultimate year of the period – it will not flow through to our forecasts for the next period.

Since 2012, we have steadily reduced our opex as our business transformation has been completed. However, our opex in 2013 was an anomaly and is not a representative base year going forward. This was recognised by the lower allowance that the AER made for 2013 and the step up it allowed in 2014. Our opex in both 2013 and 2014 was lower than the AER's allowance.

In 2014, being the penultimate year of the current regulatory period that we are proposing to use as our base year for the forthcoming regulatory period, we underspent the AER's allowance by $2.5 million.

Over the current regulatory period we estimate that we will spend very close to the AER's total allowance – i.e. a small total overspend of $19 million. This shows that we are continuing to respond to the AER's incentives. We are forecasting a positive carryover adjustment under the Efficiency Carryover Mechanism in the forthcoming regulatory period of $27.7 million. We will therefore be sharing the benefits of our opex efficiency with our customers over the forthcoming regulatory period.

11.3. Opex benchmarking

We support the AER's use of benchmarking as part of its framework for assessing DNSPs' efficient opex requirements.

Although limited forms of benchmarking have been used in previous Distribution Determinations, this is the first regulatory period in which the AER will use a range of sophisticated econometric benchmarking techniques to assess our opex requirements.

We have reviewed the benchmarking that the AER has undertaken in its 2014 Annual Benchmarking Report and in its recent Draft Distribution Determinations for the NSW and ACT DNSPs. We generally support the outcomes of this benchmarking, however there are some shortcomings in both the data that the AER has used and the way in which the benchmarking techniques have been applied.

We consider that the AER has determined a "false frontier" by using average data for the 2006 to 2013 period. This is because, in effect, it uses a 2009 average frontier to assess the efficiency of opex in 2014/15 without making appropriate adjustments for differences in DNSPs' operating conditions and obligations at these two points in time.

Further, we do not believe that the AER has appropriately adjusted for differences in the way DNSPs' present their opex. We, for example, are the only DNSP that does not capitalise any overheads. This has a profound impact on the opex that we report and means that our opex is not directly comparable to other DNSPs. Benchmarking should normalise for differences of this kind.

As a result of these types of limitations in both benchmarking data and techniques, we believe care needs to be taken in applying benchmarking results to assess efficient opex levels. In particular, it is appropriate to have regard to the balance of evidence provided by the various different benchmarking techniques, rather than placing too much emphasis on any single individual technique. By extension, the AER should not define the efficient frontier as being represented by a single business. Rather, it is more appropriate for the AER to group DNSPs in quartiles.

By its nature, there should be "winners" and "losers" from the use of benchmarking – not everyone should be a winner and not everyone should be a loser. DNSPs that are performing well relative to their peers should be recognised as performing efficiently, and rewarded accordingly. Businesses that are performing poorly relative to their peers should be transitioned to efficient levels of opex over time. It is unrealistic to expect that all DNSPs can be performing at the same levels immediately. This complements the role of the EBSS as a key regulatory mechanism for facilitating this transition and recognises that, by its nature, achieving efficiency is a continuous journey.

All of the AER's benchmarking, as well as the benchmarking that we have commissioned ourselves, supports the view that we are an efficient DNSP and are in the top quartile of our peers. We have sustained this efficient performance over many years and are clearly responding to the incentives that the regulatory regime presents.

The AER's "Annual Benchmarking Report" released in November 2014 shows that we:

- Were the second most productive DNSP measured using MTFP analysis – this is illustrated in Figure 16 on page 31 of the Report;
- Are the third most productive DNSP measured using PFP of opex – this is illustrated in Figure 19 on page 34 of the Report; and
- Have the second lowest opex per customer (compared to density and line length) – this is illustrated in Figure 12 on page 24 and in Figure 26 on page 40 of the Report;
- Have the lowest total costs per customer (compared to density) – this is illustrated in Figure 14 on page 27 of the Report;
- Have the second lowest opex per MW of maximum demand – this is illustrated in Figure 25 on page 39 of the Report.

Attachment 7 of the AER's Draft Distribution Determinations for the NSW and ACT DNSPs that was released in November 2015 focuses on opex. It shows that we:

- Are the third most productive DNSP as measured using MTFP analysis – this is illustrated in Figure A.4 on page 7-58 of Attachment 7;
- Are in the top four most productive DNSPs as measured using a variety of different opex MPFP techniques – this is illustrated in Figure A.5 on page 7-59 and Figure A.6 on page 7-64 of Attachment 7;
- Have the lowest total costs per customer (regardless of density) – this is illustrated in Figure A-7 on page 7-66 of Attachment 7; and
- Have the second lowest total opex per customer (regardless of density) – this is illustrated in Figure A-8 on page 7-67 of Attachment 7.

In order to test the AER's benchmarking analysis, we commissioned Huegin to undertake its own independent analysis of our opex using the same techniques that the AER used in their recent analysis. We have provided a copy of Huegin's report to the AER with this Regulatory Proposal.

Huegin applied the benchmarking framework and models currently favoured by the AER (provided by their consultant, Economic Insights) to the most recent data for United Energy. Huegin made the following findings:

- The stochastic frontier analysis (SFA) shows that we benchmark in the top four DNSPs and that our 2013 opex is 2 per cent below the efficient frontier (where the frontier is calculated as a weighted average of the DNSPs with an efficiency score above 0.75);

- The opex PFP analysis shows that we have the fourth highest opex partial productivity score in 2013 and also the fourth highest average opex partial productivity score over 2006 to 2013. Our opex PFP in 2013 is 2 per cent better than the efficient frontier. The analysis indicates that our opex PFP declined slightly since 2006, however we had a much smaller decline than other frontier businesses. We note that this decline does not take into account exogenous operating environment factors that affected our operations, including opex step changes that occurred during this period, including those arising out of new regulatory obligations; and
- The category analysis indicates that our average opex per customer between 2009 and 2013 is the second lowest of the DNSPs.

Importantly, the opex in the AER's and Huegin's benchmarking analysis reflects the DNSPs' respective overhead capitalisation rates. The AER recognised in its Draft Distribution Determinations for the NSW and ACT DNSPs that "Capitalisation policies may affect the amount of opex recorded". However, it did not make any allowance for this in its econometric modelling, although it did make an estimated adjustment to ActewAGL's efficiency score.

Huegin's analysis indicates that capitalisation rates vary markedly between DNSPs. It found that, on average, between 2009 and 2013 around one third of overheads were capitalised, with some DNSPs, including the frontier DNSP CitiPower, capitalising about 60 per cent of their overheads. In contrast, we do not capitalise any of our overheads. As a result, we include costs in our opex that other DNSPs capitalise. This makes us look relatively less efficient when benchmarking opex against other DNSPs. As the AER noted in its Draft Distribution Determination for the NSW DNSPs, this also means that we have a relatively high opex to capex ratio compared to our peers.

In order to highlight the sensitivity of benchmarking results to different assumptions and data, Huegin replicated the AER's results using its SFA and opex PFP but adjusted all DNSPs' opex to include capitalised overhead costs. Applying this change to the SFA resulted in us going from having the fourth highest efficiency score, at a level two per cent below the efficient frontier to being the most efficient DNSP at a level well above the efficient frontier. In this way, Huegin found that our capitalisation policy has around a 14 per cent impact on our efficiency score. Huegin also found that we benchmark as the most efficient DNSP under opex PFP analysis when capitalised overheads are included in all DNSPs' opex.

Huegin's analysis therefore supports the overall outcomes of the AER's benchmarking analysis that we are one of the best performing DNSPs in the NEM.

We draw the following conclusions from the AER's and Huegin's independent benchmarking analysis:

- Our historical opex is efficient and we are operating at or close to the efficient frontier of DNSPs in the NEM – certainly, we are in the top quartile of DNSPs in the NEM;
- Each of the benchmarking techniques shows that our opex is efficient. We do not advocate relying on any one benchmarking technique, however the consistent body of benchmarking results supports this conclusion;
- We are the most efficient if capitalised overheads are included in all DNSPs' opex;
- We are relatively efficient compared with our peers despite differences in our operating environment. We are an urban DNSP with significantly less underground network than CitiPower, who the AER has identified under some benchmarking techniques to be the frontier DNSP. We note that CitiPower enjoys the advantage of having a small network area and its overhead costs are therefore considerably lower than ours;
- We have sustained an efficient level of performance over a long period of time. We have not just arrived at our efficient levels of opex recently. This means that assessments of our efficiency are not just a function of which year, or years, is chosen for the benchmarking analysis;
- Our new business model – that has resulted from our recent business transformation program – is successful and is delivering efficient opex outcomes. This transformation provides a strong basis for us to continue to deliver efficient outcomes;
- We have continually responded to the incentives that the AER and, prior to this, the ESCV, have provided to us through the regulatory regime. This is reflected in the efficiency of our opex and the fact that our customers are sharing in the associated benefits;
- We are delivering value for money to our customers through our efficient opex; and

- Our 2014 opex provides an efficient base year for determining our opex forecast for the forthcoming regulatory period. There is no need for the AER to make any adjustment (over and above those that we have proposed) to our base year opex. We discuss this further in section 11.4.4 below.

11.4. Our forecast opex

11.4.1. Why our forecasts comply with the Rules

As noted above, this section provides a high level explanation of why our forecasts should be accepted by the AER. It should be read in conjunction with our "Operating Expenditure Overview" document that we have provided to the AER with this Regulatory Proposal.

The Rules require us to submit a total opex forecast that achieves the following opex objectives:

- To meet the expected demand for our services;
- To comply with our safety and regulatory objectives;
- To maintain network reliability; and
- To maintain the safety of our distribution network.

In addition, the AER must accept our forecasts if it is satisfied that they reasonably reflect each of the following opex criteria:

(a) The efficient costs of achieving the operating expenditure objectives;

(b) The costs that a prudent operator would require to achieve the operating expenditure objectives; and

(c) A realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

In relation to the efficiency criterion:

- The AER and Huegin's benchmarking both indicate that our historical opex is at, or close to, the efficient frontier of DNSPs in the NEM;
- We have applied the AER's preferred BST approach to forecasting opex, which is based on an efficient build-up of costs;
- Our 2014 opex provides an efficient base year for our opex forecast. We have adjusted our 2014 base year for, amongst other things, opex attributable to our AMI (currently regulated under the CROIC) that will be regulated as Standard Control Services in the forthcoming regulatory period;
- Our real labour cost escalators have been determined by independent experts, BIS Shrapnel;
- Our output growth forecast has been determined based on movements in customer numbers, circuit length and ratcheted maximum demand, in accordance with the AER's preferred approach; and
- Our step changes have been forecast using a build-up of labour and material costs that are detailed in our Opex Overview Paper. They reflect our contractual arrangements with our key service providers that have been determined through competitive tender processes and include incentives that align our, and our service providers', objectives.

In relation to the prudency criterion:

- We have structured our opex forecasts to maintain the quality, reliability and security of supply of our Standard Control Services to our customers, except where there is an explicit new regulatory requirement that we have addressed through our proposed step changes; and

- We have included a range of step changes that reflect: new regulatory obligations; existing recurrent but non-annual regulatory obligations; specific customer requests or needs; changes in our external environment; and capex-opex trade-offs. We have explained the need for, and timing of, these step changes in our Opex Overview Paper.

This chapter provides further information on our forecast opex and identifies the relevant supporting documents where additional detailed analysis demonstrating compliance with the Rules requirements is provided.

11.4.2. Key assumptions – opex

The key assumptions underpinning our opex forecasts are that:

- The 2014 base year is efficient but should be adjusted for customer service expectations and changes in input costs, outputs and productivity growth in the forthcoming regulatory period;
- The base year opex should be increased for a range of additional costs (i.e. step changes) in the forthcoming regulatory period that we did not incur in the current regulatory period;
- The forecast opex will maintain, but not improve, network reliability; and
- Our current legislative and regulatory obligations will not change materially, other than as identified through the proposed step changes (being for Power of Choice, Energy Safe Victoria Regulations and the AER's RIN reporting requirements).

Our Directors have provided a certification of the reasonableness of these key assumptions in accordance with clause S6.1.2(6) of the Rules.

11.4.3. Expenditure forecasting method

We have used a BST approach to forecast our opex for the forthcoming regulatory period. This is consistent with the approach that we proposed in our Expenditure Forecasting Method that we submitted to the AER in May 2014 and the AER's preferred approach for how it would like us to prepare our opex forecast, as detailed in its Expenditure Forecast Assessment Guideline.

A BST approach involves forecasting our opex at an aggregate level, rather than preparing individual forecasts for each category of opex, as detailed in the AER's Annual RIN.

The starting point for the BST approach is that the incentive properties of the AER's EBSS mean that our base year opex reflects prudent and efficient costs. This is because the efficiency carryover mechanism under the EBSS incentivises us to minimise our opex, while ensuring that we continue to meet our regulatory obligations and to achieve our service performance targets.

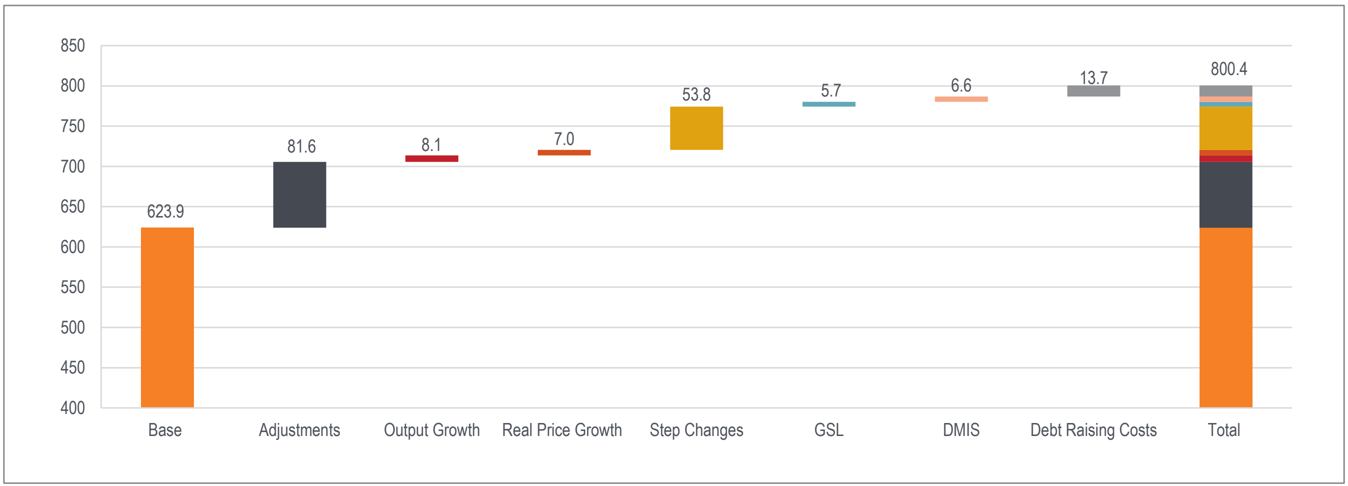
The BST approach involves the following stages:

1. Nominating a base year;
2. Applying adjustments to achieve an efficient base year opex;
3. Applying rate of change adjustments to the efficient base year opex for growth in:
    a. Labour and non-labour prices;
    b. Output; and
    c. Productivity.
4. Applying step changes (otherwise known as scope changes).

Our opex forecast for the forthcoming regulatory period is set out in Table 11-1. We are forecasting our opex to increase by $158 million, or 25 per cent, compared to the current regulatory period.

Figure 11-1 illustrates the build-up of our opex forecast for the forthcoming regulatory period.

Figure 11-1: Forecast period opex – Standard Control Services ($M, Real 2015)



11.4.4. Efficient base year inclusive of adjustments

We have chosen 2014 as our base year for our opex forecast because:

- It is the most recent full regulatory year of actual reported expenditure at the time of preparing this Regulatory Proposal;
- It is representative of our underlying operating conditions in the current and forthcoming regulatory periods;
- It reflects the efficiencies that we have achieved in transitioning to our new business model;
- We benchmark at the efficient frontier compared with our peers; and
- It reflects our response to the incentives of the regulatory regime and shows that the incentives are working.

We have adjusted our 2014 opex to achieve an efficient base year for the forthcoming regulatory period. We have:

- Added the share of our 2014 opex attributable to our AMI (currently regulated under the CROIC) that will be regulated as Standard Control Services in the forthcoming regulatory period. An explanation and justification for this opex is provided in the Revenue Capped Metering Services Overview Paper. This increases our base year opex by $19 million;
- Removed our actual 2014 Guaranteed Service Level (GSL) payments of $1.15 million;
- Removed our DMIS expenditure of $0.7 million;
- Removed $1.5 million of costs for preparing our Regulatory Proposal for the forthcoming regulatory period because they are non-recurrent in nature; and
- Added $0.8 million in efficient incremental costs associated with the 2015 regulatory year, which will be recurrent in the forthcoming regulatory period.

Table 11-3 details our efficient base year opex, inclusive of these adjustments, for each year of the forthcoming regulatory period.

Table 11-3: Efficient base year Opex including adjustments – Standard Control Services ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Efficient base year Opex including adjustments	141.1	141.1	141.1	141.1	141.1	705.6

11.4.5. Rate of change – price

We expect that the costs of two inputs – labour and materials – will increase by more than the consumer price index (CPI) in the forthcoming regulatory period. Costs of other inputs are assumed to increase in line with the CPI.

We have only adjusted our opex forecast for real price growth in labour in the forthcoming regulatory period. This is because materials comprise only a small component of our opex. We therefore expect that real price growth in materials will not have a significant impact on our opex in the forthcoming regulatory period.

The AER adopted a weighting of 62 per cent for labour and 38 per cent non-labour in its November 2014 Draft Distribution Determination for the purposes of determining the rate of price change for the NSW and ACT DNSPs' opex for their forthcoming regulatory period. We have adopted these same percentages to determine the real price growth for our opex forecast for our forthcoming regulatory period.

We engaged an independent expert, BIS Shrapnel, to forecast real labour cost escalations relevant to our opex for the forthcoming regulatory period. We have provided a copy of their report to the AER with this Regulatory Proposal.

BIS Shrapnel is a highly-regarded economic forecaster. As it notes in its report, BIS Shrapnel "won acclaim for correctly forecasting the domestic downturn in 2000/01; the subsequent boom in business investment and the chronic labour and capacity constraints by mid-decade; the rise in interest rates through 2006 to 2008, including picking the peak in housing interest rates in mid-2008; and was virtually alone in forecasting that Australia would not suffer a recession during the global financial crisis".

BIS Shrapnel prepared its forecasts using top-down and bottom-up approaches. Its bottom-up approach models industry sectors at a regional and individual category level, which are aggregated to a national level. The top-down modelling reconciles the bottom-up forecasts with prevailing trends, investment and business cycles and assumptions about the general macroeconomic outlook. BIS Shrapnel is forecasting that:

- Wages in the Australian Electricity, Gas, Water and Waste Services (EGWWS or 'Utilities) sector will slightly exceed the all industry result, given that the utilities sector generally has employees with higher skill, productivity and wage levels than most other sectors; and
- Utilities wages in Victoria will average the same as nationwide wages over the forthcoming regulatory period. This is primarily due to the similar outlook for utilities engineering construction within Victoria and Australia.

BIS Shrapnel's forecasts of growth in the Wage Price Index (WPI) are detailed in Table 11-4 below.

Table 11-4: Real rate of change – labour price (WPI) – Standard Control Services (per cent)

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

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

We applied the BIS Shrapnel labour cost escalators to our mix of employees and contractors to determine our forecast real labour cost increases.

Table 11-5 details our forecast opex increase attributable to real labour price growth in the forthcoming regulatory period.

Table 11-5: Real rate of change – labour price – Standard Control Services ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Real Price Growth	0.8	1.1	1.6	1.9	1.6	7.0

11.4.6. Rate of change – output

We have included an allowance in our opex forecast for the impact of output growth in the forthcoming regulatory period. This reflects the fact that greater output costs more to operate and maintain.

We have applied the output change measures and respective weightings that the AER used in its November 2014 Draft Distribution Determination for the NSW and ACT DNSPs' opex for their forthcoming regulatory period, being:

- Customer numbers (67.6 per cent);
- Circuit length (10.7 per cent); and
- Ratcheted maximum demand (21.7 per cent).

Table 11-6 details our forecast opex increase attributable to the impact of output growth in the forthcoming regulatory period.

Table 11-6: Rate of change – output – Standard Control Services ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Output Growth	1.2	1.5	2.1	1.7	1.6	8.1

11.4.7. Rate of change – productivity

We have determined a rate of change productivity adjustment of zero per cent for each of the five years of the forthcoming regulatory period. This is consistent with the AER's position in its Draft Determination for the NSW and ACT DNSPs, where it stated:

> *We have applied a zero per cent productivity change in estimating our overall rate of change. This is based on Economic Insights' recommendation to apply zero productivity change for the NSW and ACT distribution network service providers and our assessment of overall productivity trends for the forecast period.*[13]

Economic Insights' recommendation that the AER referred to stated:

> *We are of the view that a forecast opex productivity growth rate of zero should be used in the rate of change formula. There is a reasonable prospect of opex productivity growth moving from negative productivity growth towards zero change in productivity in the next few years as energy use and maximum demand stabilise, given the excess capacity that will exist in the short to medium term and as the impact of abnormal one–off step changes recedes. It should also be noted that recent historic*

[13] AER, "Ausgrid draft decision - Attachment 7: Operating expenditure", November 2014, page 7-154

negative measured opex productivity growth rates include the effects of some significant step changes included in previous resets.[14]

We consider that this logic applies equally to our network. Further, we note that we are the only network in the NEM that has maintained its productivity performance over time (relative to the AER's frontier) and therefore should not be penalised for overall industry negative productivity in recent years.

Table 11-7: Rate of change – productivity – Standard Control Services ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Productivity Growth	0.0	0.0	0.0	0.0	0.0	0.0

11.4.8. Step change

We have included an allowance in our opex forecast for a range of step changes for events or obligations that will cause us to incur additional costs over and above the efficient base year in the forthcoming regulatory period that we did not incur in the current regulatory period. In its Expenditure Forecast Assessment Guideline, the AER indicated that step changes should relate to either changes in regulatory obligations or capex-opex trade-offs. Accordingly, we have grouped our proposed step changes as follows:

- New regulatory obligations – annual;
- Customer response / initiated;
- Existing regulatory obligations – recurrent but non-annual;
- Change in external environment – annual; and
- Capex-opex trade-off.

In preparing and justifying our forecast step changes we have had regard for the AER's Expenditure Forecast Assessment Guideline and the requirements in the AER's Reset Regulatory Information Notice.

Table 11-8 details our step changes. Our "Operating Expenditure Overview" document provides a detailed explanation and justification of each of our step changes.

[14] Economic Insights, "Economic Benchmarking of NSW and ACT DNSP Opex", 17 November 2014, page 57

Table 11-8: Step Changes – Standard Control Services ($M, Real 2015)

New regulatory obligations – annual			2016	2017	2018	2019	2020	Total
1.	a.	Power of Choice – Metering Competition	1.2	0.5	0.6	0.6	0.6	3.5
	b.	Power of Choice – Customer Access to Data	0.3	0.3	0.3	0.3	0.3	1.7
	c.	Power of Choice – Embedded Network	0.1	0.1	0.1	0.1	0.1	0.7
	d.	Power of Choice – Demand Management IT Platform	-	-	-	0.8	0.8	1.6
	e.	Power of Choice – Network (Chapter 5 and Chapter 5A – Embedded Generation Connection, including Solar)	0.7	0.7	0.7	0.7	0.7	3.5
2.		Regulatory Information Notice reporting	-	0.4	0.4	0.4	0.4	1.6
3.	a.	Energy Safe Victoria safety obligations	0.2	0.2	0.2	0.2	0.2	1.0
	b.	Energy Safe Victoria rule changes	1.7	1.7	1.7	1.7	1.7	8.7
		Sub-total	**4.3**	**4.0**	**4.0**	**4.9**	**4.9**	**22.2**
Customer response / initiated								
4.	a.	Effortless Customer Experience Program	1.6	1.5	1.0	1.0	1.0	6.0
	b.	Stakeholder engagement	0.3	0.3	0.3	0.3	0.3	1.3
	c.	Council trees	-	1.0	1.0	1.0	-	3.0
		Sub-total	**1.9**	**2.7**	**2.2**	**2.2**	**1.2**	**10.3**
Existing regulatory obligations – recurrent but non-annual								
5.		Customer charter	-	0.7	-	-	-	0.7
6.		Regulatory submission cost	-	-	-	1.5	0.8	2.3
7.	a.	Neutral Testing	-	0.1	0.1	0.1	0.1	0.4
	b.	Network Planning and Analytics - IT Capital Programme	-	-	0.8	1.2	2.1	4.1
8.		Guideline 11 EWOV Direction	0.9	0.9	0.9	0.9	0.9	4.5
		Sub-total	**0.9**	**1.7**	**1.8**	**3.7**	**3.9**	**12.0**
Change in external environment – annual								
9.		IT security costs	0.7	0.8	0.8	0.8	0.8	4.0
10.		Insurance premiums	0.3	0.4	0.5	0.6	0.7	2.3
		Sub-total	**1.0**	**1.2**	**1.3**	**1.4**	**1.5**	**6.4**
Capex-Opex trade-off								
11.		Pole top inspection	0.6	0.6	0.6	0.5	0.2	**2.4**
Real price escalations								
			0.0	0.1	0.1	0.2	0.1	0.5
Total Step Changes			8.7	10.3	10.0	12.9	11.9	53.8

11.4.9. Guaranteed Service Levels

We apply the jurisdictional GSLs scheme that is detailed in section 6 of the Electricity Distribution Code. It requires us to make payments to customers where we do not meet specific performance standards in relation to timeliness of attending appointments, providing supply and restoring supply in the event of outages.

The AER indicated in its Framework and Approach paper that, because the Victorian GSL scheme will continue to apply in the forthcoming regulatory period, it will not apply the GSL component of the national STPIS. We accept this approach.

Our capex and opex forecasts for the forthcoming regulatory period are based on maintaining our reliability performance at the average of our last five years' performance, adjusted (i.e. made more onerous) for changes in the classification of some of our feeders from rural to urban. On the basis of these forecasts we anticipate a zero STPIS impact for reliability in the forthcoming regulatory period.

By extension, we are expecting that our GSL payments will remain at historical levels. We therefore assume that our 2014 base year GSL payments of $1.15 million will continue throughout the forthcoming regulatory period.

Table 11-9 details our forecast GSL costs in the forthcoming regulatory period.

Table 11-9: GSL costs ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
GSL	1.15	1.15	1.15	1.15	1.15	5.75

11.4.10. Debt raising costs

Table 11-10 details our forecast debt raising costs in the forthcoming regulatory period. These costs are explained and justified in section 13.6.

Table 11-10: Debt raising costs ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
Debt raising costs	2.5	2.6	2.7	2.9	3.0	13.7

11.4.11. Demand Management Innovation Allowance (DMIA)

The AER indicated in its Framework and Approach paper that it intended to continue to apply the DMIS in the forthcoming regulatory period. However, given that our Standard Control Services would be regulated under a revenue cap, it would only apply Part A of the DMIS relating to the demand management innovation allowance (DMIA).

We were allowed $0.4 million per annum for the current regulatory period (i.e. $2 million in total) as an ex-ante allowance under the DMIA for the current regulatory control period. We plan to spend this full allocation by the end of this current regulatory period on the three projects:

- Doncaster Hill District Energy Services Scheme;
- Virtual Power Plant (VPP) Pilot; and
- Bulleen Demand Response (Summer Saver) Pilot.

Given the success of each of these projects, and the likely use of our full allocation of DMIA funding in the current regulatory period, we are proposing that our DMIS allowance be increased to $6.6 million for the forthcoming regulatory period. This will enable us to explore demand management opportunities and capabilities further. Our "Demand Management & DMIS Strategy & Plan" (document UE PL 2210) that is an attachment to this Regulatory Proposal explains and justifies our proposed DMIA allowance further.

Table 11-1 details our proposed DMIS in the forthcoming regulatory period.

Table 11-11: DMIS ($M, Real 2015)

	2016	2017	2018	2019	2020	TOTAL
DMIS	2.4	1.3	1.1	1.1	0.8	6.6

12. Regulatory Asset Base and Depreciation

Key messages:

- We have adopted a value of $2,121.0 million (nominal) as our opening regulatory asset base as at 1 January 2016.
- The roll forward of the regulatory asset base has been calculated in accordance with clauses S6.2.1(e) and S6.2.3 of the Rules, using the AER's Roll Forward Model.
- Depreciation from 2011 to 2015 is based on the AER's Distribution Determination for the current regulatory period applying actual depreciation calculated using the lives defined in the AER's Post Tax Revenue Model.
- We have prepared the depreciation forecast for the forthcoming regulatory period by applying forecast asset additions, forecast asset disposals, asset lives and the AER's Roll Forward Model in accordance with the Rules' requirements.

12.1. Introduction

This chapter presents information on our Regulatory Asset Base and regulatory depreciation. We have calculated the Regulatory Asset Base value in accordance with the Rules, specifically clause 6.5.1 and schedule 6.2. Our proposed depreciation allowance also complies with the Rules' requirements, and the principles set out in clause 6.5.5(b).

The remainder of this chapter is structured as follows:

- Section 12.2 explains the derivation of the opening Regulatory Asset Base as at 1 January 2016, being the start of the forthcoming regulatory period; and
- Section 12.3 explains the derivation of our forecast Regulatory Asset Base and depreciation allowance for each year of the forthcoming regulatory period.

12.2. Opening Regulatory Asset Base as at 1 January 2016

We are required to establish an opening value for the Regulatory Asset Base as at 1 January 2016, which is the starting date for the forthcoming regulatory period. In accordance with the Rules, we have applied the AER's Roll Forward Model and Post-Tax Revenue Model to calculate this value.

Table 12-1 provides a reconciliation of our 1 January 2016 Regulatory Asset Base with the AER's estimate in its Distribution Determination for the current regulatory period. In accordance with the requirements of clause S6.2.1(e)(4) of the Rules, the value of the Regulatory Asset Base only includes capital expenditure as is properly allocated to the provision of standard control services in accordance with our Cost Allocation Method.

Table 12-1: Reconciliation of opening asset base as at 1 January 2016 to AER's Distribution Determination ($M, Nominal unless otherwise stated)

Regulatory Asset Base Components	AER's 2011 determination	Actual data	Comments / Reference
2010 opening Regulatory Asset Base	1,399.2	1,399.2	No difference.
2006 capex adjustment	(78.9)	(78.9)	No difference.
2010 net capex	124.9	128.1	See section 12.2.1 below.
2010 Depreciation	(64.9)	(64.9)	No difference.
Opening Regulatory Asset Base 2011	**1,380.2**	**1,383.5**	
2011 to 15 capex	955.0	996.7	Annual variance shown in the Roll Forward Model. Reasons for variances provided in Capital Overview attachments.
Equity raising (Capex)	3.6	3.6	As per the AER's Distribution Determination
2011 to 15 contributions	(144.6)	(68.1)	Annual variance shown in the Roll Forward Model. Reasons for variances provided in Capital Overview - New Customer Connections attachment.
2011 to 15 disposals	0.0	(1.1)	Annual variance shown in the Roll Forward Model. The total value of disposals was slightly higher than forecast.
2011 to 15 depreciation	(508.0)	(518.5)	Annual variance shown in the Roll Forward Model. Higher depreciation due to higher capex in the current period. Details of calculation set out in the Roll Forward Model.
2011 to 15 funding of capex	27.0	43.1	Nominal cost of capital applied, as required by the application of the Roll Forward Model.
2011 to 15 inflation on Regulatory Asset Base	209.9	209.2	Actual inflation rather than forecast inflation has been applied. Details are set out in the Roll Forward Model.
Indexation of the 2010 Regulatory Asset Base	0.0	19.1	See section 12.2.2. below
Return on 2010 capex difference	0.0	1.9	Foregone return as calculated by the Post-Tax Revenue Model.
Closing Regulatory Asset Base 2015	**1,923.1**	**2,069.3**	$M, Real 2015
Application of revised 2016 CPI forecast	49.5	51.7	A revised 2016 inflation forecast of 2.5 per cent is applied instead of the forecast of 2.57 per cent which was adopted by the AER in its 2010 Determination. This has the effect of reducing the Regulatory Asset Base escalation amount however this reduction is offset by a higher than forecast closing asset base because our total capex exceeded the AER allowance for the period.
Opening Regulatory Asset Base 2016	**1,972.6**	**2,121.0**	$M, Nominal

Note - 2015 data is the latest available forecast.

As explained in Table 12-1, we are proposing an opening Regulatory Asset Base value of $2,121.0 million for the forthcoming regulatory period, which is a variance of $148.5 million from the forecast Regulatory Asset Base value in the AER's Distribution Determination for the current regulatory period. The key factors driving this variance are explained below.

12.2.1. Capex differences in 2010

In its Distribution Determination for the current regulatory period, the AER estimated our capex for 2010 in order to calculate the opening the Regulatory Asset Base as at 1 January 2011. The Rules[15] require us to make an adjustment in the forthcoming regulatory period to correct for any difference between the AER's estimate and our actual capex for 2010. The table below sets out the calculation in accordance with the Rules.

Table 12-2: 2010 capex variance and the indexation of the 2010 Regulatory Asset Base ($M, Nominal)

Previous Period Adjustment	Expenditure	Contributions	Disposals	Total
2010 Forecast	129.8	(4.9)	0.0	**124.9**
2010 Actual	138.9	(10.6)	(0.2)	**128.1**
Difference	**9.2**	**(5.6)**	**(0.2)**	**3.3**

Actual capex was higher in 2010 due to investment required to maintain safety and reliability levels.

12.2.2. Indexation of the 2010 Regulatory Asset Base

We have included an adjustment as a result of the CPI indexation of the 2010 Regulatory Asset Base from the previous period. The calculations in the table below reflect the amount not included in the calculation of the 2011 Opening Regulatory Asset Base in the AER's Distribution Determination for the current regulatory period.

Table 12-3: Indexation of the 2010 Regulatory Asset Base and calculation of the foregone return ($M, Nominal)

Regulatory Asset Base Indexation	
Opening Regulatory Asset Base 2010	1,399.2
Less: Previous period adjustment (2005)	(78.9)
Adjusted Opening Regulatory Asset Base 2010	1,320.3
CPI Mar 2009	*166.2*
CPI Sep 2009	*168.6*
Indexation	*1.0144*
Prior period indexation adjustment (Adjusted Opening 2010 Regulatory Asset Base x (Indexation-1))	**19.1**

The opening Regulatory Asset Base value for 2011 specified in the AER's Distribution Determination for the current regulatory period was obtained by escalating the opening Regulatory Asset Base value as at 1 January 2006, which was expressed in July 2004 prices, using inflation data for six years. The AER also made other adjustments to the 2006 opening Regulatory Asset Base value expressed in 1 July 2010 dollar terms, with the result that the opening Regulatory Asset Base value for 2011 was stated in July 2010 terms. The opening Regulatory Asset Base value for 2011 should have been expressed in January 2011 prices.

[15] Clause S6.2.1(e)3.

Accordingly, the opening Regulatory Asset Base value for 2011, which was used for the purpose of the Distribution Determination for the current regulatory period, will need to be escalated using an approach that delivers five and a half years' worth of inflation. An inflation adjustment of this type will ensure that the opening Regulatory Asset Base value for 2016 is stated correctly in January 2016 dollars. As noted above, the opening Regulatory Asset Base value at the commencement of the forthcoming regulatory period must be expressed in current prices for input to the post-tax revenue model.

Our proposed approach is consistent with the Australian Competition Tribunal which found that the AER had erred in its approach to the indexation of the Regulatory Asset Base values for Jemena Electricity Networks (JEN)[16].

12.3. Regulatory asset base for the forthcoming period

The table below presents a summary of the amounts, values and inputs we used to derive our forecast Regulatory Asset Base value for each year of the forthcoming regulatory period. In accordance with the Rules[17], only actual and estimated capex attributable to the provision of Standard Control Services in accordance with our cost allocation methodology has been included in the Regulatory Asset Base.

The assumptions adopted in rolling forward the Regulatory Asset Base in the forthcoming regulatory period are:

- Forecast capex is consistent with the categories and amounts presented in this Regulatory Proposal;
- Depreciation has been calculated on a straight line basis, using the asset lives presented in Table 12-5, and in accordance with the requirements of clause 6.5.5(a) of the Rules; and
- Asset disposals are forecast to be zero.

The forecast Regulatory Asset Base for each year of the forthcoming regulatory period is shown in Table 12-4.

Table 12-4: Regulatory asset base for 2016 – 2020 ($m, real 2015)

$M	2016	2017	2018	2019	2020
Opening Regulatory Asset Base	2,069.3	2,188.6	2,302.0	2,404.8	2,493.5
Inflation on Opening Regulatory Asset Base	0.0	0.0	0.0	0.0	0.0
Plus capex (Excl. Funding)	249.9	256.2	253.8	226.8	212.1
Plus Funding Costs	5.5	5.6	5.5	4.9	4.6
Less customer contributions	(17.7)	(18.1)	(18.3)	(18.7)	(18.5)
Less regulatory depreciation	(118.4)	(130.3)	(138.1)	(124.3)	(128.9)
Less disposals	0.0	0.0	0.0	0.0	0.0
Closing Regulatory Asset Base	**2,188.6**	**2,302.0**	**2,404.8**	**2,493.5**	**2,562.7**

Note: The values contained in this table have been calculated as per the requirements of the post-tax revenue model.

12.3.1. Depreciation methodology and asset lives

We have used the AER's Post-Tax Revenue Model to calculate depreciation in accordance with clause 6.5.5 of the Rules. New assets are depreciated according to the standard lives for each asset class. Existing assets are

[16] The Tribunal only made orders in respect of JEN, concluding that the other Victorian DNSPs were precluded from raising the matter before the Tribunal because they had not broached the matter with the AER.
[17] S6.2.1(e)(4)

depreciated over their remaining asset lives. The opening asset value at 1 January 2016 has been calculated by applying the AER's Roll Forward Model.

The table below shows the standard asset lives for each asset class and their remaining lives. The standard asset lives have been adjusted to reflect the actual capex during the 2011 to 2015 period. The remaining life calculation has taken into account the original calculation approved by the AER in 2011. The Roll Forward Model has been used to establish the remaining lives of assets as at 1 January 2016.

The asset classes and standard lives shown in the table below are the same as those accepted by the AER in its Distribution Determination for the current regulatory period, with the exception of the SCADA (10 year life) asset class. We propose that this new asset class will come into effect from 1 January 2016, and it will contain SCADA, network control and protection system capex that is incurred from 1 January 2016.

The creation of the new SCADA (10 year) asset class recognises that SCADA, network control and protection system assets have much shorter lives than the primary distribution system assets. The establishment of the new SCADA (10 year) asset class is in accordance with clause 6.5.5(b)(1) of the Rules, which requires the depreciation profile to reflect the nature of the asset class over the economic life of that asset class.

Table 12-5: Asset lives

Asset	Standard lives	Remaining life as at 1 January 2016
Sub – transmission	60	26.6
Distribution system	35.6	25
Standard metering	n/a	1
Public lighting	n/a	1
SCADA (5 Year –Asset)	5	2.1
Non-Network ICT	5	3.2
Non- Network - Other	7.5	2.5
Neutral screen services	n/a	0.1
Overloaded transformers	n/a	0.1
SCADA (10 Year –Asset)	10	5
Land	n/a	n/a

We note that, for the purposes of this Regulatory Proposal, we have not removed any current asset classes and reallocated their residual values to other asset classes. However, we reserve the right to do so following the AER's Draft Determination.

12.3.2. Forecast regulatory depreciation for the forthcoming regulatory period

Our forecast depreciation for the forthcoming regulatory period is set out in Table 12-6.

Table 12-6: Forecast depreciation ($M, Real 2015)

	2016	2017	2018	2019	2020
Regulatory depreciation	118.4	130.3	138.1	124.3	128.9

Our forecast depreciation reflects:

- The opening asset base and forecast Regulatory Asset Base values described above, which include estimates of capital additions and disposals;
- The use of straight-line depreciation; and
- The standard and remaining asset lives set out in Table 12-5.

Our forecast depreciation is calculated in accordance with the requirements set out in clause 6.5.5(b) of the Rules.

It is noted that the AER's Framework and Approach paper explains that the AER will use forecast depreciation (as opposed to actual depreciation) to establish the Regulatory Asset Base at the commencement of the 2021–25 regulatory control period. It should be noted that this decision does not affect the calculation of the regulatory allowance for depreciation for the forthcoming regulatory period.

13. Rate of return, inflation and debt and equity raising costs

Key messages:

- The return on capital should compensate our debt and equity holders for the opportunity cost of lending/investing their funds in our network. Setting a fair rate of return is therefore essential for us to continue to invest in our network to deliver safe and reliable service to our customers.
- For the forthcoming regulatory period, we propose a rate of return of 7.38 per cent per annum based on a proposed return on debt of 5.67 per cent, a proposed return on equity of 9.95 per cent and a proposed gearing of 60 per cent.
- The rate of return that is being put forward draws upon methods and elements that have been set out in the AER's Rate of Return Guideline, including, for instance, the benchmark gearing, and the application of the benchmark efficient entity concept.

13.1. Introduction

This Chapter provides a description of our proposed rate of return, and includes coverage of debt and equity raising costs for the forthcoming regulatory period. The chapter is structured as follows:

- Section 13.2 provides an overview of our proposed approach to estimating the rate of return, with an additional description of the return on debt provided in section 13.3, and further commentary on the return on equity provided in section 13.4.
- Section 13.5 summarises our departures from the AER's Rate of Return Guideline; and
- Section 13.6 discusses our debt-raising costs, while section 13.7 addresses our equity raising costs.

13.2. Rate of return

13.2.1. Overview of the rate of return

The Rules provide that our return on capital should be calculated as the allowed rate of return multiplied by the Regulatory Asset Base. Our allowed rate of return should be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the DNSP in respect of the provision of Standard Control Services. In other words, the allowed rate of return objective should be satisfied[18]. In addition, the rate of return must be calculated as the weighted average of the return on equity and the return on debt, determined on a 'nominal vanilla basis' that is consistent with an estimate of the value of imputation credits[19].

We need to earn an appropriate and fair rate of return so that we can continue to invest in our $2.1 billion network in a manner that best supports the long-term interests of our customers. The return on capital aims to compensate our debt and equity holders for the opportunity cost of either lending or investing their funds in our network — and these funds are essential to deliver safe and reliable electricity distribution services to our customers.

For the forthcoming regulatory period, we propose an allowed rate of return of 7.38 per cent per annum, which has been derived using the formula for a standard, nominal vanilla WACC[20]. The overall return on capital is comprised

[18] Australian Energy Market Commission, National Electricity Rules (version 71), 9th April 2015. Clause 6.5.2 (c).

[19] Australian Energy Market Commission, National Electricity Rules (version 71), 9th April 2015. Clause 6.5.2 (d).

[20] $WACC^n = R_e^n \times (1 - L) + R_d^n \times L$

Where:

- R_e^n is the nominal return on equity
- R_d^n is the nominal return on debt
- L is the level of gearing, and is taken as the ratio of debt to the sum of the values of debt and equity. The face value is usually recorded for debt, while the market value is used for equity.

of a proposed return on debt of 5.67 per cent, a proposed return on equity of 9.95 per cent, and a proposed gearing of 60 per cent. Table 13-1 details the key components of our proposed rate of return.

Table 13-1: Basic summary of the cost of capital results

	Value (per cent)
Return on equity	9.95%
Return on debt	5.67%
Gearing	60%
Gamma	0.25
Nominal vanilla Weighted Average Cost of Capital (WACC)	7.38%
Inflation	1.78% to 2.5%

Source: Post-tax revenue model submitted with our Regulatory Proposal.

The rate of return that we propose allows sufficient compensation, consistent with the NEL and the Rules. The rate has been obtained after applying aspects of the AER's Rate of Return Guideline, such as:

- The 10 year term to maturity for debt;
- The proposed approach to gearing[21]; and
- An examination of extrapolation methodologies at the time of each return on debt reset[22].

However, to ensure that we can continue to attract the necessary funds, we have departed from the AER's Rate of Return Guideline by estimating:

- The return on debt:
  - For a benchmark efficient entity with a BBB credit rating;
  - Assuming a transition from the hybrid to the trailing average debt management strategy;
  - Including the cost of swap contracts (23bppa)[23] and the cost of the new issue premium (27bppa)[24]; and
  - Nominating future averaging periods in such a way as to make it easier for us to efficiently align our debt management practices with the rate of return on debt.
- We have also estimated the return on equity using an approach that:
  - Gives consideration to a range of relevant models, while recognising that no model is perfect, and that a prudent strategy would be to avoid picking one primary model over others;
  - Combines return on equity estimates from the series of models in a way that provides a more sustainable, stable and robust 'consensus' forecast than is likely from the AER's foundation model approach;
  - Is based on an estimate of the market risk premium that considers all relevant and current evidence, relies significantly on forward-looking estimates of return, and incorporates the value of imputation credits in a

[21] AER, Better Regulation, Rate of Return Guideline, December 2013; section 4.3.2.

[22] AER, Better Regulation, Explanatory Statement, Rate of Return Guideline, December 2013; section 8.3.3.

[23] UBS, Financeability - Debt issuance and capital structure, UBS response to the Networks NSW request for financeability analysis following the AER Draft Decision of November 2014, prepared for Ausgrid by Peter Kingston, UBS, 16 January 2015.

UBS, Analysis of Liquidity of Interest Rate Swaps, UBS response to the TransGrid request for interest rate risk analysis following the AER Draft Decision of November 2014, prepared for TransGrid by UBS, January 2015.

UBS, Transaction Costs and the AER Return on Debt Draft Determination, prepared for Jemena by UBS, March 2015.

[24] CEG, The new issue premium, a report prepared for Citipower, Jemena, Powercor Australia, SA Power Networks, AusNet Services and United Energy, by Dr Tom Hird, Competition Economists Group, October 2014; paragraph 25, page 6.

manner that is consistent with how the tax building block is calculated in our proposed forecast revenue model; and

- Is based on a Sharpe-Lintner (S-L) CAPM beta estimate that recognises that there is limited Australian data available. The equity beta therefore relies partly on foreign data from the USA.

Although our proposal differs from the Rate of Return Guideline, we consider that the proposal better meets the Rule requirements and the National Electricity Objective (NEO) than the approach that has been put forward by the AER. When determining the rate of return, we considered each of the factors that are set out in section 6.5.2 of the Rules. The current rate of return proposal achieves the objectives set out in clauses 6.5.2 (b) and 6.5.2 (c).

We propose to update the rate of return estimates, and the underlying risk-free rate, using an actual averaging period. We will thereby conform to the AER's Rate of Return Guideline. The averaging period will be proposed in advance in order to provide us with the opportunity to undertake hedging with a view to aligning our actual funding costs with the rate of return. The nominated averaging period will pertain to estimates of the return on debt evaluated for the first year. The return on debt, and therefore the rate of return, will be updated annually.

13.2.2. Macro-economic outlook and perspective on inflation

The AER generally adopts a projection for inflation which is at or close to 2.5 per cent. The AER approach to preparing inflation forecasts makes use of the following steps[25]:

- Draw upon the near term projections for inflation from the latest available version of the RBA Statement on Monetary Policy. Use the results from the Statement for underlying inflation to produce inflation forecasts for the next two years;
- For the next eight of 10 years, insert a value of 2.5 per cent in the corresponding cells of the AER's inflation forecasting template. The value of 2.5 per cent is the mid-point of the range for inflation targeting that is used by the RBA;
- The values of the inflation forecasts for the individual years are transformed into an index, with a value of 100 being assigned to the year preceding the current year; and
- A geometric mean is then fitted to the entire series, making use of the ultimate value of the index in the final year out of 10 years (or 11 years, if the immediately preceding year is also counted).

We do not believe that the AER's method is producing an optimal and reliable forecast for inflation at the present time. Although we have maintained the standard AER forecast of 2.5 per cent inflation in the PTRM, we consider that this approach is an interim measure.

For January 2015, we can report that the implied break-even inflation rate over a five-year horizon was 1.778 per cent. This figure has been calculated as an average across 20 business days. The implied break-even inflation over a ten year forecast horizon was 2.207 per cent. These values have been determined by comparing the yields, at tenors of 5 and 10 years, between treasury bonds and treasury indexed bonds. The comparison was undertaken using the Fisher equation.

For regulatory purposes, a five year tenor is an appropriate term to maturity to consider for an inflation forecast, because the escalators that underpin the cost components which enter the AER's post-tax revenue model, are generally prepared with respect to a medium term horizon of five years. The relevant cost escalators are those used for labour and materials costs. The escalators underpin the projections, in nominal terms, of the components of operating expenditure and/or capital spending. Forecasts of the cost escalators, and of the operating and capital expenditure components themselves, are generally only provided for the next five years. The relevant cost build-ups are not available for a more extended time horizon.

An appropriate way to address these matters, and the more detailed matters detailed in the CEG report, would be to make amendments to the PTRM pursuant to clause 6.4.1(b) of the NER[26]. Pending an amendment to the PTRM,

[25] See, for instance: AER, Final Distribution Determination, Aurora Energy Pty Ltd, 2012–13 to 2016–17, April 2012.

[26] We have previously written to the AER about a deficiency with the PTRM insofar as it presumes that imputation credits can be paid out even in circumstances in which there are no cash dividends available for distribution. Email correspondence from Jeremy Rothfield, United Energy, to Kenny Yap, Australian Energy Regulator, 2 February 2015. See also section 14.4 of this Regulatory Proposal.

our proposal adopts the AER's approach to inflation consistent with the current version of the PTRM. In doing so, we do not concede that the current version of the PTRM is correct in this respect. If these issues are not adequately addressed in the context of an amendment to the post tax revenue model, then we reserve our position to potentially make compensatory adjustments as part of its revised rate of return proposal. The revised regulatory proposal will be lodged in the context of the revocation and substitution process which will take place subsequent to the preliminary distribution determination.

In Table 13-1, we have presented a range of forecasts for inflation, with the lower bound value determined as break-even inflation, and the upper bound value evaluated using the AER's method.

A further analysis of inflation is contained in a report on this topic from the Competition Economists Group[27].

13.3. Rate of return on debt

13.3.1. Efficient debt financing costs

Efficient debt financing costs capture the required yield (or interest) on issued debt plus the transactions costs associated with any derivative products that are used to achieve that interest cost. In contrast to the situation with the return on equity, the yield can be observed by looking at the price and promised payments on traded bonds for firms with a similar degree of risk as a benchmark entity in our circumstances. Note that the circumstances are measured, in part, by our credit rating.

The Rules require that the return on debt should be estimated in such a way as to contribute to the achievement of the rate of return objective. The Rules also require that regard be had to relevant estimation methods, financial models, market data and other evidence. Consistent with the Rules, we propose a return on debt as a function of the following:

- Benchmark characteristics — we propose a 10-year term to maturity and a BBB credit rating (from Standard and Poor's);
- Data source and extrapolation method — we propose using a yield estimate that is commensurate with the benchmark credit rating. The estimated yield will be published by an independent third party, and will be subject to the application of a suitable extrapolation method. The result will give the best fit to traded bond data over the relevant averaging period, consistent with recent decisions by the Australian Competition Tribunal. For the first and subsequent year cost of debt estimates, we will also provide estimates from Nelson-Siegel yield curves, and par yield curves, in order to help inform the best possible decision about the spot cost of debt. Par yield curves are estimated using an extended Nelson-Siegel yield curve specification; and
- Implementation — we propose to apply a transition from the hybrid to a trailing average, portfolio return on debt. We have investigated a varying weights trailing average model which was prepared in order to into take account the finding that the business will raise more/less debt in years when net capex is higher/lower than average. We will not put forward the varying weights trailing average model at this juncture, but foreshadow the possibility of applying such an approach at a later date.

13.3.2. Benchmark characteristics

Consistent with the Rate of Return Guideline, we consider that a 10-year term to maturity is an appropriate tenor to adopt when assessing the return on debt for a benchmark efficient firm[28]. However, we disagree with the view, espoused in the Rate of Return Guideline, that the benchmark credit rating should be set at BBB plus[29]. We propose to apply a BBB benchmark credit rating on the basis that CEG has found, that in each year from 2009 to 2013, the

[27] CEG (2015c), Measuring risk free rates and expected inflation, a report for United Energy, prepared by Dr Tom Hird, Competition Economists Group, April 2015.

[28] AER, Better Regulation, Explanatory Statement, Rate of Return Guideline, December 2013; section 8.3.3.

[29] AER, Better Regulation, Explanatory Statement, Rate of Return Guideline, December 2013; section 8.2.

median credit rating of regulated energy network service providers was BBB, amid a clear trend of downgrades across the industry[30].

13.3.3. Transition from the hybrid debt management strategy

We propose that we should be compensated for a cost of debt that is derived on the basis that the benchmark efficient entity previously managed its debt consistent with the "hybrid" debt management strategy. The hybrid method necessitated the use of interest rate swaps to hedge the base interest rate exposure to the level prevailing at the beginning of each regulatory period. The approach thus described was a way of managing to the rate on-the-day, rate setting method previously used by the AER to set the cost of debt allowance. The on-the-day period was the interval which generally corresponded to the commencement of a regulatory period. The legacy arrangements then define the starting point for any transition to a new benchmark efficient debt management strategy. The transition involves a departure from the Rate of Return Guideline.

The AER has, in recent decisions, expressed the view that the hybrid strategy was the benchmark efficient debt management strategy under the on the day approach previously used by the AER to set the cost of debt[31]. Notwithstanding this, the AER proposes a transition from regulatory practice rather than from benchmark efficient practice. We consider that this transition is inconsistent with the Rules and, in particular, the allowed rate of return objective.

We propose to adopt a transition to a trailing average from a hybrid debt management strategy. This is in line with new analysis that we have undertaken, considered in conjunction with the expert advice that we have received from CEG. The hybrid transition will provide an estimate of the return on debt that better reflects the efficient debt financing costs of the benchmark efficient entity[32]. We consider that the transition to a trailing average approach proposed in the Rate of Return Guideline does not meet the requirements of the Rules.

The transition from the hybrid approach proposed involves:

- Immediate adoption of a 10 year trailing average DRP (measured relative to 10 year swaps). This means that for the first year of the forthcoming regulatory period, the DRP would be estimated as a 10-year trailing average, and this trailing average estimate would be updated in each subsequent year. The AER should, therefore, adopt a trailing average estimate of the DRP component; and
- A base rate of interest that transitions from an 'on-the-day' base rate of interest to a trailing average base rate of interest over 10 years.

13.3.4. Data source and extrapolation method – historical data

We propose that a DRP of 2.47 per cent be adopted for the nine calendar years to 2014. This is the best estimate, derived by CEG, of the historical average risk premium relative to 10 year swap rates over the recent past.

13.3.5. Describe approach to period up to 2015

We will propose an averaging period to occur later in 2015. In this Regulatory Proposal, a placeholder estimate based on the period from 2 January 2015 to 30 January 2015 is comprised of the following components:

a) 1.82 per cent for the spread-over-swap in 2015 (which, when combined with 2.47 per cent for the previous nine years, results in an average spread-to-swap over 10 years of 2.40 per cent); and

b) 2.69 per cent for the base rate of interest (which is a simple average of 1 to 10 year swap rates taken out in the transition from a hybrid to the trailing average cost of debt).

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30 See *Rate of Return on Debt, Proposal for the 2016 to 20120 Regulatory Period*, United Energy, April 2015; Table 2.1 shows the trend over time in the credit ratings assigned by Standard and Poor's to regulated energy businesses or their parent entities.

31 AER, ActewAGL draft decision, Attachment 3: Rate of return, pages 3-115 to 3-116.

32 UE, Letter to Mr Warwick Anderson, General Manager, Australian Energy Regulator. Submission in relation to the first round of regulatory determinations under the new rules, 6th February 2015; see page 9, on "Implementing the Trailing Average Method for Debt".

CEG (2015), The hybrid method for the transition to the trailing average rate of return on debt. Assessment and calculations for United Energy, prepared for United Energy by Dr Tom Hird, Competition Economists Group, April 2015.

This results in a cost of debt of 5.09 per cent, expressed on a semi-annual basis. To this value can be added swap transactions costs (23bp) and the new issue premium (27bp). The summation of all of the components results in a cost of debt of 5.59 per cent, which is expressed on the basis of semi-annual yields. The value for the cost of debt becomes 5.67 per cent which, when transformed into an annual equivalent rate, is the appropriate standard used for regulatory purposes.

13.3.6. Selecting a data source and extrapolation method – 2015

We propose to perform bespoke analysis on the 2015 averaging period to inform the best estimate of the 10 year BBB cost of debt. We note that there will potentially be two averaging periods in 2015, one which applies to the preliminary determination (to be made in October 2015) and the other being used for the substitute determination (which is to be made in April 2016). The analytical methods that are applied to the 2015 averaging periods will also be used in future, when considering averaging periods in 2016 and in subsequent years of the regulatory period.

13.3.7. Selecting a data source and extrapolation method – 2016 and beyond

We propose using a third-party published yield estimate that is extrapolated using either: The methodology recently proposed by SA Power Networks (SAPN); or the AER's extrapolation methodology as set out in its recent draft decisions for the NSW DNSPs, ActewAGL and JGN[33]. We propose using a five step method for selecting the appropriate third-party data source and extrapolation method in each year of the regulatory period:

a) Identify all relevant third party return on debt data series (e.g., Bloomberg (FVC or BVAL) and the RBA corporate debt estimates);

b) Estimate the 10 year BBB return on debt for each independent third party data series, using the SAPN and AER extrapolation methodology for the averaging period;

c) Identify all relevant bonds that meet predetermined objective criteria[34], and compare the yields on these bonds to each third party estimate over the averaging period;

d) Estimate yield curves, using yield to maturity data, and par yield curves, using bond prices in order to obtain the highest quality estimates of the contemporaneous cost of debt. These estimates will permit a comparison with the results from the third party indicator series; and

e) Select the return on debt estimate (or combination of estimates) that best fits the sample of bonds identified in step (c).

13.3.8. Implementation

To implement the hybrid method of transition to a trailing average, we need to update the return on debt for each year of the regulatory period. The annual updating of the return on debt will give rise to changes in annual revenues (and tariffs), and will be automatically effected through a formula in our revenue forecast model. Annual updating of the return on debt is a change from accepted practice in the current regulatory period, and follows from changes to the Rules, and from the implementation of the Rate of Return Guideline.

Using our proposed approach and the parameters set out in Table 13-2, we estimate a return on debt of 5.67 per cent in respect of the sample averaging period, and the historical period over which the spread over swap was measured.

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[33] AER, Draft decision, Jemena Gas Networks (NSW) Ltd, Access arrangement 2015–20, Attachment 3: Rate of return, November 2014, page 3-150.

[34] The criteria are set out in: UE, *Rate of Return on Debt: Proposal for the 2016 to 2020 Regulatory Period;* prepared by United Energy, April 2015.

Table 13-2 Components of the rate of return on debt (hybrid approach to the trailing average)

		Source of information
Benchmark credit rating	BBB	Rate of return on debt: Proposal for the 2016 to 2020 regulatory period
Measurement period for the trailing average, portfolio return on debt (calendar years)	2006 to 2015	CEG (2015a); CEG (2015b)
Historical trailing average spread to swap, calendar years 2006 to 2014	2.47%	CEG (2015a); CEG (2015b)
Spread to swap over recent averaging period, 20 business days to 30th January 2015	1.82%	CEG (2015a); CEG (2015b)
Combined, trailing average spread to swap, average from 2006 to 2015	2.40%	CEG (2015a); CEG (2015b)
Average of 1 to 10 year swap rates during reference period (January 2015)	2.69%	CEG (2015a); CEG (2015b)
Estimated yield (semi-annual basis)	5.09%	CEG (2015a); CEG (2015b)
Include the transactions costs of swaps (23 basis points)	5.32%	Underlying data from UBS (2015a) and (2015b)
Include the new issue premium (27 basis points)	5.59%	CEG (2014a)
Cost of debt: Estimated yield (expressed as an effective annual date)	5.67%	CEG (2015b)
Debt risk premium relative to yields on 10-year CGS	3.03%	UE calculation
Risk-free rate (AER interpolation method)	2.64%	UE calculation
Implication of the analysis of optimal hedging ratios	To be quantified	

Source: CEG (2015a), *Critique of the AER's JGN draft decision on the cost of debt*, prepared by Tom Hird and Daniel Young, CEG, April 2015. CEG (2015b), *The hybrid method for the transition to the trailing average rate of return on debt. Assessment and calculations for United Energy*, prepared for United Energy by Dr Tom Hird, Competition Economists Group, April 2015. CEG (2015c), *Measuring risk free rates and expected inflation*, a report for United Energy, prepared by Dr Tom Hird, Competition Economists Group, April 2015. ESQUANT (2015), *Evaluating Methods for Extrapolating Australian Corporate Credit Spreads published by the Reserve Bank of Australia*, a report prepared for United Energy and Multinet Gas, 27 March 2015, ESQUANT Statistical Consulting.

Table 13-3 Current estimates of the rate of return on debt (averaging period of January 2015)

For comparison as reference points (contemporaneous cost of debt during January 2015 averaging period)		
Estimates of the cost of debt at a 10-year term to maturity		**Source of information**
Bloomberg BBB BVAL curve extrapolated using SAPN method	4.75%	Table 5; CEG (2015a) plus 10-year swap rate (2.95%)
RBA corporate bond spread extrapolated using SAPN method	4.79%	Table 5; CEG (2015a) plus 10-year swap rate (2.95%)
Results from contemporaneous estimates of the cost of debt: Nelson-Siegel yield curves (note that the results from the estimation of par yield curves will also be submitted)	4.845%	Table 7; ESQUANT (2015a)
Results from contemporaneous estimates of the cost of debt: Par yield curves		ESQUANT (2015b)
Forecast inflation rate (evaluated over reference period, January 2015)	1.78% to 2.50%	CEG (2015c)
Debt-raising costs (recovered in cash flows), measured as "levelised" costs	19.9 bppa	Incenta (2015)

Source: CEG (2015a), *Critique of the AER's JGN draft decision on the cost of debt*, prepared by Tom Hird and Daniel Young, CEG, March 2015. CEG (2015b), *The hybrid method for the transition to the trailing average rate of return on debt. Assessment and calculations for United Energy*, prepared for United Energy by Dr Tom Hird, Competition Economists Group, April 2015. CEG (2015c), *Measuring risk free rates and expected inflation*, a report for United Energy, prepared by Dr Tom Hird, Competition Economists Group, April 2015. ESQUANT (2015), *Evaluating Methods for Extrapolating Australian Corporate Credit Spreads published by the Reserve Bank of Australia*, a report prepared for United Energy and Multinet Gas, 27 March 2015, ESQUANT Statistical Consulting.

Other sources: UBS, *Financeability - Debt issuance and capital structure, UBS response to the Networks NSW request for financeability analysis following the AER Draft Decision of November 2014*, prepared for Ausgrid by Peter Kingston, UBS, 16th January 2015. UBS, *Analysis of Liquidity of Interest Rate Swaps, UBS response to the TransGrid request for interest rate risk analysis following the AER Draft Decision of November 2014*, prepared for TransGrid by UBS, January 2015. UBS, *Transaction Costs and the AER Return on Debt Draft Determination*, prepared for Jemena by UBS, March 2015. CEG (2014), *The new issue premium*, a report prepared for Citipower, Jemena, Powercor Australia, SA Power Networks, AusNet Services and United Energy, by Dr Tom Hird, Competition Economists Group, October 2014; paragraph 25, page 6.

13.3.9. The implications of an optimal hedging ratio

The analysis of the hybrid form of the transition to a trailing average return on debt relies on a preliminary position being taken that the benchmark efficient entity is 100 per cent hedged.

In the explanatory statement to the Rate of Return Guideline, the AER formed the view that the efficient response of a business to the "rate-on-the-day" approach to measuring the cost of debt was to use interest rate swaps in order to better align the actual cost of debt to the "on the day" cost of debt that underpinned the AER allowance. As reported by the AER[35]:

> *Given the observed practices of regulated network businesses and the definition of the benchmark efficient entity, we consider that the following practice is likely to constitute an efficient debt financing practice of the benchmark efficient entity under current 'on the day' approach:*
>
> *holding a debt portfolio with staggered maturity dates and using swap transactions to hedge interest rate exposure for the duration of a regulatory control period.*

The AER formed its view after considering submissions from a number of the treasury officers in private, regulated network businesses. The corporate treasurers had reported that interest rate risk was being managed by hedging

[35] AER, Better Regulation, Explanatory Statement, Rate of Return Guideline, December 2013; section 7.3.3, page 107.

against movements in base rates away from the risk-free rate assumed by the regulator during a relevant averaging period for a regulatory reset[36].

More recently, the AER has relied on theoretical advice from Martin Lally that a business would have used interest rate swaps to better align its actual cost of debt to the "on the day" cost of debt that underpinned the AER's allowance. The advice that Lally provided to the AER relied implicitly on presumptions that[37]:

- There is not an inverse relationship between the debt risk premium (DRP) and the base level of interest rates; and
- The transactions costs associated with the use of fixed interest swaps are either low or zero.

In practice, neither of the two assumptions is likely to be sustained. There is evidence from academic studies, commencing with Longstaff and Schwartz (1995)[38], that credit spreads are inversely related to the base level of interest. In the presence of negative correlation, there are benefits to be gained from leaving a proportion of the base rate of interest unhedged, with the proportion here referring to a fraction, by market value, of the overall debt portfolio. The overall cost of debt allowance is comprises both the base rate of interest and the DRP.

The intuition behind the result of a certain hedging proportion can be illustrated by conceiving of a situation in which there is a perfect inverse relationship between the base rate of interest and the DRP. Under such a scenario, the cost of debt would always be constant because any movement in the base rate of interest would be offset by an equal and opposite movement in the DRP.

In a context of perfect negative correlation, the adoption of a trailing average for the rate of return on debt would provide a perfect hedge to the on the day allowance because the cost of debt is constant. Therefore, the trailing average would always be equal to the 'on the day' allowance. In contrast, hedging the base rate of interest would result in a degree of separation between the actual costs incurred by a business and the 'on the day' allowance. This is because the on-the-day cost of debt would remain constant, while the combination of a hedged base rate of interest and a trailing average DRP would cause the actual cost of debt incurred by a business to be more volatile than the on-the-day cost of debt. In essence, therefore, there already exists a natural hedge between the DRP and base interest rates in this example. To fully hedge base interest rates would diminish the value of the natural hedge and thereby worsen rather than improve the overall hedge to the 'on the day' allowance.

The example provided above considers an extreme situation. However, we consider that an algebraic representation can be prepared to show that for any given negative correlation between the DRP and base rates of interest, there is a specific proportion of hedging of base interest rates that is efficient, and which will give rise to the best hedge of the overall 'on the day' cost of debt allowance. Thus, one approach to arrive at the benchmark efficient strategy would be to research the best estimate of the negative correlation between the DRP and base rates of interest, and to use the result obtained to arrive (mathematically) at the most efficient combination of the hybrid form of the transition to a trailing average rate of return on debt, and an immediate transition to a trailing average return of debt. Empirical studies in published journals have quantified the negative relationship between the base rate of interest and the DRP, and to draw upon this research would result in a positive weight being assigned to the full trailing average rate of return on debt[39]. Moreover, the transactions costs incurred by a business as it engages in vanilla interest swaps could potentially serve as a form of deterrent, and encourage the business to hedge to a lesser degree than it otherwise would.

The position we have taken is that, while interest rate swaps are clearly important and relevant, the presumption that hedging might be undertaken for a full 100 per cent of the value of a debt portfolio may result in an over-statement of the true position.

[36] Ibid; section 7.3.3, page 104.

[37] Lally, Transitional Arrangements for the Cost of Debt, Dr Martin Lally, Capital Financial Consultants Ltd, 24th November 2014.

[38] Longstaff, and Schwartz, *A simple approach to valuing risky fixed and floating rate debt*, Journal of Finance, July 1995. According to the authors: "Using Moody's corporate bond yield data, we find that credit spreads are negatively related to interest rates and that durations of risky bonds depend on the correlation with interest rates, (page 789).

[39] Consider, for instance:

Duffee (1998), *The relation between treasury yields and corporate bond yield spreads*, Journal of Finance, 53, page 2225-2241.

Huang and Kong (2003), "Explaining credit spread changes: New evidence from option-adjusted bond indexes", Journal of Derivatives, Fall 2003, pages 30-44.

Lepone and Wong (2009), *Determinants of Credit Spread Changes: Evidence from the Australian Bond Market*, Australasian Accounting, Business and Finance Journal, 3(2).

13.3.10. Varying weights trailing average formulation

The AER has previously adopted a position that equal and invariant weights should be used in the calculation of a trailing average return on debt[40]. However, the AER has not undertaken substantive analysis to inform its position. There are advantages to the adoption of a varying weights formulation, both from a risk management perspective and in terms of the achievement of a closer alignment between the rate of return on debt and the actual costs of debt that will be incurred by a regulated entity. More specifically:

- A varying weights trailing average model can allow for the possibility of growth in the Regulatory Asset Base over time. When calculating a trailing average over a 10 year nominated period, a higher weight can be apportioned to those years for which the recorded growth in the Regulatory Asset Base is above average. If there are periods in the past or in future for which the growth rate in capital spending has been high, or is expected to be high, then the debt raising effort is likely to be concentrated around those years. Accordingly, the company's weighted average actual cost of debt will be more strongly influenced by observations of the spot cost of debt in high growth years. Note that a similar logic will also apply, albeit in reverse, to those years in which the growth in the Regulatory Asset Base has been below average; and
- From the perspective of the management of the base rate risk, a varying weights trailing average method allows for a closer concordance between the base rate component of the regulatory return on debt, and the base rate component of the (weighted average) actual cost of debt. The company can enter into hedging transactions at the start of the regulatory period. Let it be assumed that there are a number of different hedges of different tenors (say, a one-year hedge, a two-year hedge, and a hedge which expires after three years, and so on). If a business is subject to a varying weights trailing average regime, then there is scope to adjust the dollar amounts that are hedged corresponding to future time intervals which fall within the different tenor ranges. The value of each hedge transaction can be set so as to coincide more closely with the expected growth in the Regulatory Asset Base in each of the distinct future periods which coincide with a particular hedge. The extent of the exposure to base rates in each future period will then correspond more closely with the compensation to be provided through the varying weights return on debt formula.

We have developed and analysed a varying weights trailing average model in order to better understand how the scheme would work. The model took into account the expected increase in the Regulatory Asset Base, and the issuance and retirement of debt with a 10-year term to maturity. At this juncture, we consider that the hybrid form of the transition to a trailing average rate of return on debt is already sufficiently advanced. The calculation methods and data sources have been documented by CEG. A varying weights trailing average method would result in an additional overlay of detail in the hybrid calculation. We are not arguing for the adoption of the varying weights approach at this stage. However, we reserve the right to put forward a varying weights model in our Revised Regulatory Proposal.

13.3.11. Further information

In the course of preparing this Regulatory Proposal, we have considered each of the factors that are set out in clause 6.5.2 (h) of the Rules[41]. Further details of our proposal for the rate of return on debt are provided in a supporting document, the "Rate of Return on Debt: Proposal for the 2016 to 2020 Regulatory Period", that we prepared. There are also a significant number of supporting expert reports.

13.4. Rate of return on equity

The return on equity is the return required by shareholders when providing equity capital. Although there are proxies available for the return on debt, such as bond yields, there are no immediate and direct means for observing, on an *ex ante* basis, what investors require by way of equity returns. Accordingly, estimates of the rate of return on equity have to be derived from market data and other evidence, making use, in general, of asset pricing models and other methods.

[40] AER, Better Regulation, Explanatory Statement, Rate of Return Guideline, December 2013; section 7.3.5, page 115.

[41] Australian Energy Market Commission, National Electricity Rules (version 71), 9th April 2015. Clause 6.5.2 (h).

Clause 6.5.2 (f) of the Rules stipulates that the return on equity for a regulatory control period must be estimated such that it contributes to the allowed rate of return objective. Clause 6.5.2 (f) states that, in estimating the return on equity under paragraph (f), regard must be had to the prevailing conditions in the market for equity funds[42].

The AER remains committed to a "foundation model" approach which, in our opinion, is incapable of providing an objective and holistic evaluation of the evidence.

13.4.1. Critique of the AER's foundation model approach for estimating the return on equity

The AER's implementation of the foundation model approach is not capable of delivering an estimate of the return on equity that is consistent with the allowed rate of return objective, and that is reflective of prevailing conditions in the market for equity funds. There is evidence to support a departure from the foundation model approach that was applied in the draft decision for Jemena Gas Network.

The AER's implementation of the foundation model approach does not take into account two important pieces of empirical evidence:

- Stocks with low beta estimates earn higher returns than predicted by the S-L CAPM – an empirical phenomenon which could be dealt with by implementing the Black CAPM to derive one estimate of the cost of equity; and
- Stocks with high book-to-market ratios persistently earn higher returns than predicted by the S-L CAPM – which could be dealt with by implementing the Fama-French model to derive one estimate of the cost of equity.

The AER has a single metric for determining the relative risk of a benchmark energy network compared to the market – a regression-based estimate of beta based upon a small sample of Australian-listed stocks. The total sample size is nine stocks, of which only four remain listed. The AER has decided that beta lies within a range of 0.4 to 0.7 and has then dismissed any further consideration:

- There is no theoretical or empirical reason as to why the implied cost of equity from the Black CAPM would be constrained according to the upper bound from the regulator's narrow range for beta;
- The AER has excluded the Fama-French model from consideration because of a debate amongst researchers over exactly what is proxied by the high-minus-low factor (HML) factor[43], and because of alleged uncertainty over implementation. However, neither the AER nor Handley (2014) reaches any conclusion about how to account for the empirical performance of high book-to-market stocks over time and across markets; and
- The AER has excluded dividend discount model analysis from consideration at an industry level because of claims about imprecision. The implied beta estimate of 0.94 is considered by the AER to be too high and too variable. However, if there are characteristics other than regression-based estimates of beta that matter for returns (such as the book-to-market ratio), and if the S-L CAPM implies that expected returns fall short of realised returns (as has been established through empirical tests), then there is no reason to believe that an equivalent beta of 0.94 from the dividend discount model is too high. Furthermore, the beta estimates for firms that have been obtained using the dividend discount model technique are less variable than regression-based beta estimates.

The AER's consideration of alternative models to the S-L CAPM is made with a view that the S-L CAPM should be relied upon unless the AER can be persuaded to depart from such a position. The AER's approach is incongruous with the Rules because the method acts to constrain information that would otherwise lead to an allowed return which best represents the prevailing cost of funds.

In a recent series of reports on the cost of equity[44], SFG has outlined a specific computation of the cost of equity that:

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[42] Australian Energy Market Commission, National Electricity Rules (version 71), 9th April 2015. Clause 6.5.2 (f).

[43] The HML premium is 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.

[44] SFG, 2013 DDM, Reconciliation of dividend discount model estimates with those of the AER, prepared by SFG Consulting, 10th October 2013.

SFG, 2014 Black, Cost of equity in the Black Capital Asset Pricing Model, prepared by SFG Consulting, 22nd May 2014.

SFG, 2014 DDM, Alternative versions of the dividend discount model and the implied cost of equity, prepared by SFG Consulting, 15th May 2014.

SFG, 2015 Beta & Black, Beta and the Black Capital Asset Pricing Model, prepared by SFG Consulting, 13th February 2015.

SFG, 2015 Cost of equity, The required return on equity for the benchmark efficient entity, prepared by SFG Consulting, 25th February 2015.

- Uses four estimation models in order to mitigate estimation error; and
- Uses models that specifically address the empirical limitations of the S-L CAPM.

The SFG integrated approach best meets the rate of return objective, which is that the allowed return should represent the prevailing cost of funds.

13.4.2. Results from empirical tests of asset pricing models

A regulator which seeks to determine an appropriate rate of return should not simply consider the theoretical properties of different models, but should to also examine empirical performance. Irrespective of the attractions of a particular model at a theoretical level, investors are unlikely to want to use it, if it has a record of poor performance. Instead, investors will be inclined to adapt the model so as to overcome its known shortcomings. There is ample evidence, for example, of independent experts or of valuation practitioners making adjustments to the input parameters used in the SL CAPM. For example, an analysis by NERA of valuation practitioner reports found that in 66 of 142 cases, the relevant practitioners had added a firm specific premium to the cost of equity[45].

The empirical performance of a model is thus a key consideration when assessing its suitability. The AER has chosen to disregard the goodness-of-fit of a model to historical data, and has, instead, concentrated on the estimation of parameters for use in the S-L CAPM. An important criterion for a model to fulfil is that it should do a good job of predicting future returns. This could mean that a model is accurate, but accuracy is a difficult goal to achieve with finance data that is notoriously noisy. A more suitable hurdle to set is bias. The distinction between bias and precision can be explained in the following way. If a model is imprecise, or inaccurate, then its predictions will be subject to a high degree of variability, although, over time, the occasions that the model over-predicts should be counteracted by the occasions on which it under-predicts. In contrast, bias is not so readily overcome. A model which is known to produce biased forecasts will be of less value to investors, because investors will know that, on average over time, the model delivers results that are either incorrect or unreliable.

Under instructions from a consortium of businesses, NERA Economic Consulting undertook tests of asset pricing models, specifically the Black CAPM and the S-L CAPM. The purpose of the tests was to assess the empirical performance of the models and to ascertain whether there is evidence against the restrictions that each model imposes[46]. The results of the tests would help to inform us as to whether there was any merit in the AER's approach of giving prominence to the S-L CAPM as the primary foundation model.

NERA made use of the monthly Share Price and Price Relative data taken from SIRCA from January 1974 to December 2013, and formed portfolios on the basis of past estimates of beta. In addition to examining the SL CAPM and the Black CAPM, NERA also investigated a naïve model, which stipulated that the mean returns to all equities were identical. The naïve model was formed by setting the equity beta equal to one in the SL CAPM. NERA postulated that a pricing model should at least be able to outperform, empirically, a naïve model of this kind.

NERA applied both in-sample tests and out-of-sample tests to determine whether there is evidence against the restrictions that each model imposes. As noted by NERA, if the restrictions that an asset pricing model imposes do not hold, then the model will, in general, produce biased estimates of the return required on equity. Thus, evidence against a model is evidence that the model will generate biased estimates of the return required on equity.

In-sample tests are full-sample tests, whereas out-of-sample tests split the full sample up, typically in a recursive manner, into data used to estimate a model and data used to evaluate forecasts generated by the model.

From its in-sample tests, NERA was able to establish that:

- There is little evidence of bias in the naïve model;
- There was statistically significant evidence of bias in the S-L CAPM; and

SFG, 2015 DDM, Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network, prepared by SFG Consulting, 18th February 2015.

[45] NERA (2013), The Market, Size and Value Premiums, A report for the Energy Networks Association, June 2013; chapter 8, page 67.

[46] NERA (2015), Empirical Performance of Sharpe-Lintner and Black CAPMs, prepared by NERA Economic Consulting, February 2015.

- There was little evidence of bias in the Black CAPM. Specifically, Wald tests of the restrictions imposed by the Black CAPM did not reject the model[47].

When performing out-of-sample tests, NERA included, in the testing process, a variant of the SL CAPM which it labelled as the "AER CAPM". The model was named in that way because the equity beta used in the model was formed by taking a weighted average of an unadjusted beta (equal to 0.55) and one. The weights used were two-thirds for the unadjusted estimate of beta, and one third on unity. This technique, which delivers a value for the equity beta of 0.7, represents an approach that might be taken by a regulator when assessing the return on equity for a regulated utility.

NERA reported from its regression results that there was:

- Little evidence of bias in the naïve model;
- Statistically significant evidence of bias in the SL CAPM;
- Statistically significant evidence of bias in the AER CAPM; and
- Little evidence of bias in the Black CAPM.

The results obtained by NERA were not just statistically significant, but were also economically significant. A small subset of the results can be explained here. In out-of-sample tests, NERA reported that the mean forecast error, for portfolio 3, was 4.49 per cent per annum, when the S-L CAPM was used, and when realised, excess returns to the market portfolio were employed in the formulation of model predictions[48]. The mean forecast error of 4.49 per cent was statistically significant at the 5 per cent level of significance. The equity beta for portfolio 3 was reported by NERA to be 0.67, which is close to the beta that has been set by the AER for a regulated energy utility. Thus, the magnitude of the forecast error from the S-L CAPM was such that it under-estimated the returns from portfolio 3 by 449 basis points per annum, on average. The empirical work was in respect of time intervals from January 1979 to December 2013. Clearly, that degree of under-statement represents a considerable margin of error.

If the return on equity allowance for a business was, on average over time, under-stated by this amount, then the business would be compelled to postpone investment. The business would recognise that it was not earning a fair rate of return on equity, and would therefore formulate plans which resulted in less investment, or delayed investment. Consumers would ultimately suffer a serious detriment.

The error in the assessed return on equity would need to be corrected so as to prevent, or bring an end to the under-compensation. If a suitable correction were applied, then the final result for the return on equity would be materially preferable with respect to the long-term interests of consumers.

The outcomes of the empirical assessments performed by NERA would justify a policy of giving no weight to the return on equity results from the S-L CAPM when determining the overall rate of return on equity for regulatory purposes. However, following advice from SFG about the capacity of a certain group of asset-pricing models to contribute to the overall rate of return objective, we have decided that the S-L CAPM should not be eliminated from consideration altogether. We have adopted a weighting scheme for model results which was devised by SFG Consulting[49], which is described further in section 13.4.3 below. The weight ultimately accorded to the outputs from the S-L CAPM is low but is non-zero.

13.4.3. Our assessment of the return on equity

We considers that, when estimating the return on equity, the following principles should be upheld:

a) A range of models should be employed – to meet the allowed rate of return objective, and to ensure that the estimate best meets the NEO[50], and the Revenue and Pricing Principles (RPP)[51].

[47] A Wald statistic uses unrestricted parameter estimates and an estimate of the covariance matrix of the unrestricted parameter estimates to test whether a set of restrictions is true.

[48] NERA (2015), Empirical Performance of Sharpe-Lintner and Black CAPMs, prepared by NERA Economic Consulting, February 2015; Table 5.2, page 40.

[49] SFG, *The required return on equity for regulated gas and electricity network businesses*, prepared by SFG Consulting, 6th June 2014.

[50] NEL, s. 7. An equivalent statement is made in the National Gas Law, s. 23.

[51] NEL, s. 7A (2). An equivalent statement is made in the National Gas Law, s. 24.

b) All relevant estimation methods, financial models, market data and other evidence should be considered; and

c) Regard must be had to the prevailing conditions in the market, including contemporaneous data and estimation methods that reflect prevailing conditions rather than average historical conditions.

We maintain the view that the models which should be chosen are those that are capable of providing information which will improve the quality of the final estimates of the required return on equity. The relevant question to be posed is whether a model is sufficiently fit for purpose as to be able to contribute to the attainment of the allowed rate of return objective.

Consistent with the explanatory statement to the Rate of Return Guideline, our proposal recognises that no model is perfect or provides all relevant information on the return on equity. If models are to have a role in estimating the return on equity, then they should not only have a theoretical grounding, but should also be capable of being shown to be empirically relevant. The AER has undertaken only a theoretical assessment of models to date, and has not undertaken an empirical assessment of model outcomes to assess their relevance.

In broad terms, our proposed approach is to:

- Identify relevant return on equity models, making use, where relevant, of the results of asset pricing model tests;
- Identify relevant evidence which may be used to estimate parameters within each of the relevant return on equity models;
- Estimate model parameters for each relevant return on equity model, based on relevant market data and other evidence;
- Separately estimate the required return on equity using each of the relevant models; and
- Synthesise the model results as a weighted average of the individual estimates to derive an estimate of the required return on equity.

We have examined a number of suitable models, applying a "model adequacy test" which has been developed based upon the notion that, when model predictions are compared with actual, subsequent outcomes, the predictions should not exhibit any statistically significant upward or downward bias[52]. Assessing models against a benchmark of this kind is consistent with, and is indeed a mathematical representation of, the AER's own NPV=0 condition outlined in the Rate of Return Guideline. To-date, the results of the tests from asset-pricing models have been used informatively rather than in a strict determinative way. We note that models such as the Fama French three-factor model, and the dividend discount model (DDM), are not well-suited for rigorous testing using out-of-sample tests because historical data is not available in Australia for a large number of periods extending back into the past. However, the insufficiency of historical data in no way suggests that either the Fama French model or the SFG dividend discount model are inadequate.

The principal models that we have examined are:

- The S-L CAPM;
- The Black CAPM;
- The Fama-French three-factor model; and
- The dividend discount model.

We have also obtained estimates of the input parameters for these models, relying on expert advisers to perform the empirical work. Our estimates of the key return on equity parameters are set out in Table 13-4 below. The estimates for the equity beta and for the expected return on the market have clearly deviated from the Rate of Return Guideline. More specifically:

[52] Refer to 13.4.2. See also:
NERA (2015), Empirical Performance of Sharpe-Lintner and Black CAPMs, prepared by NERA Economic Consulting, February 2015

- The estimate of the equity beta in the S-L CAPM (0.82 compared with 0.70 in the Rate of Return Guideline[53]) recognises that there is limited Australian data available to derive a reliable estimate, and so partially relies on foreign data from the US; and
- The estimate of the return on the market relies to some degree on forward-looking estimates of return, and properly incorporates the value of imputation credits, consistent with the manner in which the tax building block is calculated within our proposed revenue forecast model. The overall value of the market risk premium (MRP) that has been used is 8.17 per cent by comparison with 6.50 per cent in the Rate of Return Guideline.

Table 13-4 Key return on equity parameters

Risk-free rate over the averaging period (January 2015)	2.64%
S-L CAPM beta estimate	0.82
MRP	8.17%
Value of a dollar of imputation credits (gamma)	0.25
Distribution rate	0.70
Value of a distributed imputation credit (theta)	0.35
Ratio of return from dividends and capital gains to total returns in the AER's post-tax revenue model	0.90
Gearing	60%

Source: *Rate of Return on Equity: Proposal for 2016 to 2020*, United Energy. *Assessment of Gamma: Proposal for 2016 to 2020*, United Energy. SFG, *Beta and the Black Capital Asset Pricing Model*, prepared by SFG Consulting, 13th February 2015. SFG, *The required return on equity for the benchmark efficient entity*, prepared by SFG Consulting, 25th February 2015. SFG, *Estimating gamma for regulatory purposes*, prepared by SFG Consulting, 6th February 2015.

We have, in broad terms, endorsed the method for assessing the MRP, which has been set forth by SFG in reports prepared in 2014 and 2015[54]. The results for the MRP are presented below in Table 13-5. SFG makes use of four separate measures that have been evaluated as follows:

- An historical MRP which has been calculated as an arithmetic average of excess returns to the market portfolio, assessed over the period from 1883 to 2013. SFG (2015) has made use of the figures from NERA (2015) [55]. The MRP estimated obtained, of 6.56 per cent, is an unconditional mean;
- The "Wright" approach is named after Professor Stephen Wright who examined the return on equity for the Victorian gas distributors in 2012[56]. This method makes use of the same set of historical data that has been supplied by NERA (2015). However, following Wright, the historical average real return to the market portfolio is evaluated, rather than historical average excess returns. Thus, the Wright approach presumes that the real return required on equity is constant across different market conditions. The real return to the market portfolio was combined with a measure of inflation expectations, to provide a figure for the nominal return on the market (11.64 per cent). The implied MRP, using the risk-free rate from the January 2015 averaging period, was therefore 9.00 per cent;

[53] AER, Better Regulation, Rate of Return Guideline, December 2013; page 15.

[54] SFG, *The required return on equity for the benchmark efficient entity*, prepared by SFG Consulting, 25th February 2015.
SFG, *The required return on equity for regulated gas and electricity network businesses*, prepared by SFG Consulting, 6th June 2014.

[55] NERA, Historical Estimates of the Market Risk Premium, prepared by NERA Economic Consulting, February 2015.

[56] Wright (2012), Review of risk free rate and cost of equity estimates: A comparison of UK approaches with the AER, Professor Stephen Wright, Birkbeck, University of London, October 2012.

- The DDM estimates of the MRP were drawn from a recent application of the SFG (2015) endogenous growth model[57]. SFG (2015) used a market-wide variant of their model to estimate the expected return over a two month period from November to December 2014. The result obtained from the model was 11.37 per cent, after grossing up the return by the value of imputation credits (with gamma equal to 0.25). The implied MRP was worked out to be 8.73 per cent, with a risk-free rate of 2.64 per cent; and
- In relation to the results from independent expert (valuation practitioner) reports, SFG (2014) set the estimate of the MRP conservatively at 6 per cent. This figure has to be transformed into an estimate of the nominal return on the market (8.64 per cent), which can then be grossed up for the value of imputation credits by applying the level perpetuity method. The result for the nominal return on the market, inclusive of the value of imputation credits, is then 9.57 per cent, which implies a transformed value for the MRP of 6.93 per cent. An important point to note is that in determining the result for the grossed up MRP, SFG did not make any adjustments to the return on the market to take account of the uplift factors that are often applied by valuation practitioners. In contrast, NERA Economic Consulting, which examined 142 independent expert reports in 2013, sought to fully incorporate the impact of the alterations that were often made by valuation practitioners[58]. NERA (2013) found that valuation practitioners sometimes made upward adjustments to the risk-free rate so as to lift the WACC that they were computing. In other instances, the final cost of capital was revised by practitioners, but information was not provided as to how the revisions had been made, although there was no evidence that changes had been made to the cost of debt.

For the different estimates of the MRP, SFG (2014) devised a weighting method to be applied, the basis of which can be explained as follows:

- A 50 per cent weight was allocated to the forward-looking DDM estimate, with the remaining 50 per cent weight given to the three approaches that are based on historical averages;
- Equal weights were assigned to the Ibbotson and Wright approaches for processing the historical market return data, because the two approaches represent two ends of a spectrum in relation to the processing of that data; and
- A share was also given over to the results from independent expert valuation reports, noting that the MRP estimate (of 6.93 per cent) was conservative because it had not been influenced by any uplift factors or adjustments to the historically low risk-free rate.

The weighted average result for the MRP was determined to be 8.17 per cent, and this value was used by SFG (2015) in a number of asset pricing models, although not in the DDM.

[57] SFG, 2015 DDM, Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network, 18th February 2015; section 2.3, page 8.

[58] NERA (2013), The Market, Size and Value Premiums, a report for the Energy Networks Association, prepared by NERA Economic Consulting, June 2013; section 8, page 65.

Table 13-5 Estimates of the required return on the market and the MRP (per cent)

Method	MRP	Required return on the market	Weighting
Historical excess returns (Ibbotson approach)	6.56	9.20	20
Historical market returns (Wright)	9.00	11.64	20
Dividend discount model	8.73	11.37	50
Independent expert valuation reports	6.93	9.57	10
Weighted average	8.17	10.82	100

Source: SFG, *The required return on equity for the benchmark efficient entity*, prepared by SFG Consulting, 25th February 2015. See Table 5.

Note: Risk-free rate of 2.64 per cent for January 2015. Gamma set to 0.25, theta to 0.35. The calculation methods and justification for the weighting scheme are set out in SFG, *The required return on equity for regulated gas and electricity network businesses*, prepared by SFG Consulting, 6th June 2014.

The estimates of the input parameters were then applied to the models to obtain results for the return on equity. A weighted average of the estimates from each model was taken to obtain a return on equity of 9.95 per cent, as shown in Table 13-6. Taking an average that places a positive weight on each model promotes stable returns over time. The weighting of the model outputs was based on advice from subject matter experts as to the relative strengths and weaknesses of each of the models.

The results from the application of the four principal asset pricing models considered by SFG are presented below in Table 13-6. The modalities for each model and the manner in which the parameter estimates were selected can be described as follows:

- The equity beta that is used in the S-L CAPM and the Black CAPM was sourced from SFG (2013). SFG compiled beta estimates (re-levered to 60 per cent) for nine domestic firms (five of which are currently listed), and 56 international energy network businesses, and thereafter ascertained that the best available estimate for the equity beta is 0.82[59];
- The estimate of the zero beta premium employed in the Black CAPM was sourced from an SFG (2014) report on the Black CAPM[60]. SFG (2014) estimated the zero beta premium empirically by performing a regression of portfolio returns on two independent variables, namely (1 – portfolio beta) and (portfolio beta × the market return). The estimation technique therefore relied on the following core variables: stock returns, government bond yields, market capitalisation, book-to-market ratio and industry classification. Historical returns information was sourced in respect of the period from 1994 to 2013. The value of the zero beta premium obtained and used by SFG (2014) was 3.34 per cent. Importantly, portfolios of stocks were formed by sorting firms according to size (market capitalisation), as well as book-to-market characteristics (book-to-market refers to the ratio of the book value of the stock to its market value) [61]. SFG also sought to maintain an even industry composition across portfolios;
- For all of the model results shown in Table 13-6, the implied value of the equity beta in the S-L CAPM was derived by taking the equity risk premium (which is equal to the cost of equity minus the risk-free rate), and dividing by the weighted average market risk premium, which had been evaluated to be 8.17 per cent;
- For the Fama French model, the estimates of the risk premiums for high minus low (HML) and small minus big (SMB) were sourced from a recent SFG update on the Fama-French model[62]. The estimates of the empirically determined Fama French betas, or risk coefficients, were taken from the same source document. Note that SFG obtained parameter estimates for the Fama French three factor model using data from Australia and from

[59] SFG, 2013, Regression-based estimates of risk parameters for the benchmark firm, 24th June 2013.

[60] SFG, 2014, *Cost of equity in the Black Capital Asset Pricing Model*, prepared by SFG Consulting, 22nd May 2014.

[61] Ibid; paragraph 76, page 21.

[62] SFG, 2015, *Using the Fama-French model to estimate the required return on equity*, prepared by SFG Consulting, 13th February 2015.

the USA[63]. Note that Australian observations on the risk factors (which are the product of the Fama French beta and its corresponding premium) were effectively given twice as much weight; and

- The SFG dividend discount model was used to obtain specific information about the required return on the market for listed energy stocks. As has been reported in SFG (2015, DDM), the sample of firms used was the same as that employed by the AER for the purpose of evaluating the equity beta[64]. SFG (2015, DDM) compared the forecast return on equity for the nine listed energy networks with the broader, market-wide return, and found that the implied risk premium ratio was 0.94. The empirical work made use of analyst projections for the two months ending in December 2014. The risk premium ratio is determined by dividing the equity risk premium, for the narrow group of nine stocks, by the broader market risk premium, as evaluated using the DDM. The risk premium ratio can thus be viewed as being akin to the equity beta in the S-L CAPM. Note that in Table 13-6 below, the ratio of 0.94 is the only result that was taken from the DDM. The value of 0.94 was actually used in conjunction with the weighted average market risk premium of 8.17 per cent from Table 13-5, thereby giving an equity risk premium, inclusive of a value assigned to imputation credits, of 7.68 per cent.

A further consideration is the manner in which the estimates of the return on equity, obtained from the different methods, were combined to deliver an overall result. SFG has discussed its weighting scheme in SFG (2014, ROE)[65].

Table 13-6: Estimates of the required return on equity for a benchmark efficient entity

	Risk free component (per cent)	Equity risk premium (per cent)	Cost of equity (per cent)	Weight (per cent)	Implied SL beta
S-L Capital Asset Pricing Model	2.64	6.68	9.32	12.50	0.82
Black Capital Asset Pricing Model	2.64	7.29	9.93	25.00	0.89
Fama and French Model	2.64	7.29	9.93	37.50	0.89
Dividend discount model	2.64	7.68	10.32	25.00	0.94
Overall cost of equity	2.64	7.31	9.95	100.00	0.89

Source: SFG, *The required return on equity for the benchmark efficient entity*, prepared by SFG Consulting, 25th February 2015. See Table 6. The additional calculations of the equity risk premium, and of the implied beta in the SL CAPM were performed separately.

SFG (2014, ROE) has explained the rationale for the return on equity weighting scheme in the following broad terms:

- A 25 per cent weight is applied to the dividend discount model, with 75 per cent then remaining for the three asset pricing models.
- Of the 75 per cent weight that has been made available for asset pricing models, approximately half (37.5 per cent) has been earmarked for the Fama French model, and half to the CAPM (37.5 per cent). Thus, an equal weight has been assigned to the possibilities that either a reliable estimate of required returns for exposure to the HML factor is available, or that the estimate of required returns for exposure to the HML factor is over-stated[66].

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63 Ibid; Table 1, page 27.

64 SFG, 2015 DDM, Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network, 18th February 2015; section 5.4, page 30.

65 SFG, 2014 ROE, The required return on equity for regulated gas and electricity network businesses, 6th June 2014; paragraph 26, page 9.

66 In the Fama-French three factor model, the HML factor is measured as the difference in returns to a portfolio of stocks with a high book-to-market ratio for equity, compared to a portfolio of stocks with a low book-to-market ratio for equity.

- The total weight that can be applied to the CAPM is 37.5 per cent. In the context of practical application, the essential difference between the two forms of CAPM is in respect of the value of the intercept term on the y-axis. The same values of beta and of the required return on the market are used for both models. The Black CAPM uses an empirical estimate of the intercept, which has been selected to provide the best possible fit to the observed data. The S-L CAPM uses a theoretical lower bound for the intercept, which is that the intercept cannot possibly be lower than the risk-free rate. SFG (2014, ROE) applied twice as much weight to the Black CAPM as to the S-L CAPM precisely because, in the case of the former model, the intercept term is empirically determined.

SFG (2014, ROE) has reported that the final estimate of the required return on equity is relatively insensitive to the proposed weighting scheme.

Although our proposal differs from the Rate of Return Guideline, we consider that our methods better meet the Rules' requirements and the NEO than the approach that has been put forward by the AER. In estimating the return on equity, we have considered prevailing conditions in the market for funds (as required by clause 6.5.2(g)). A separate attachment, the "Rate of Return on Equity: Proposal for the 2016 to 2020 Regulatory Period", provides further details of our suggested approach for measuring the return on equity.

13.5. Departures from the AER's Rate of Return Guideline

The Rules require that we identify the particular issues in relation to which departures have been proposed from the Rate of Return Guideline. The tables presented below explain the points of differentiation.

Table 13-7: Departures of this Regulatory Proposal from the Guideline: Equity

Guideline	Regulatory Proposal	Rationale
Relevant models to consider: SL-CAPM, Black CAPM, Fama French Three Factor Model and the Dividend Growth Model.	Adopts the approach in the Guideline.	These are relevant models for estimating the required return on equity.
Which models should be used in setting the allowance: SL-CAPM, Black CAPM and the Dividend Growth Model.	Diverges because we would use all four models.	The Fama French three Factor Model provides valuable insights and corrects for well-documented biases that are not explicitly considered by the other models. The AER does not consider or produce empirical estimates from the Black CAPM, and makes only limited use of the DGM. No regard is had to empirical estimates from the Fama French Three Factor Model.
How the information gleaned from the models should be synthesised: The SL-CAPM, implemented in the way the AER has done in the past, should (continue) to play the central role. Any other information should take a secondary role, at most being used to inform the estimate of one of the SL-CAPM parameters. In many instances, the information is simply being used to guide the choice of a parameter estimate from within a narrow range of values, rather than to contribute to a full, quantitative evaluation of that parameter estimate.	All of the relevant information (i.e. all four models including the two principal ways to approach the SL-CAPM) should contribute directly to the allowed rate of return on equity, calculated as an average which has been weighted according to the specific contributions that each model can make.	There is no correct basis for the AER's Ibbotson inspired implementation of the S-L CAPM to be given the greatest weight, nor for it to constrain the extent to which other inputs can affect the computation of the allowed rate of return for equity.
Implementing the SL-CAPM:	The beta should be at least 0.8 and equal weighting should be given to the Ibbotson and Wright	Network businesses have greater systematic risk than the AER assumes and the S-L CAPM is downwardly biased for low beta stocks and

Guideline	Regulatory Proposal	Rationale
The SL-CAPM should be implemented using a current risk free rate, an equity beta of 0.7 and a market risk premium of 6.5 per cent that is largely guided by historical estimates.	approaches to estimating the MRP. When implementing the Ibbotson approach, the market risk premium should be the arithmetic average for the longest available series – that is 6.56 per cent. The appropriate role for the DGM is as a model to be employed directly in delivering an estimate for the return on equity for a group of stocks which are comparators for the benchmark efficient entity. The AER uses the DGM to inform the choice of an estimate of the MRP from within a range.	for stocks. The S-L CAPM also does not accurately capture the returns for stocks with high book-to-market ratios. The Ibbotson and Wright approaches for estimating MRP are based on the same historical data but different methodologies return different results – and, as such, regard should be given to both. When seeking to employ the Ibbotson approach, the AER identifies a range for the historical MRP of 5.1 per cent to 6.5 per cent. The low end of this range is flawed in that it relies on an incorrectly adjusted dividend yield series, and irrelevant geometric averages.

Source: UE, *Rate of Return on Equity: Proposal for the 2016 to 2020 Regulatory Period*, prepared by United Energy, April 2015.

Table 13-8 provides a summary of departures from the Rate of Return Guideline, but does not seek to discuss components of the cost of debt that were omitted from the Rate of Return Guideline altogether. By way of example, the new issue premium, optimal hedging ratios, and swap transaction costs are issues that were not properly considered by the AER when it prepared the Rate of Return Guideline. There is no reference to these components in the table below, however any premium or transaction cost that is payable by the benchmark efficient entity is discussed and evaluated in this Regulatory Proposal, and supporting documents.

Table 13-8: Departures of this Regulatory Proposal from the Guideline: Debt

Guideline	Regulatory Proposal	Rationale
Trailing average, "on the day" method or a hybrid: Leaving aside the issue of transition (discussed below), ultimately the return on debt allowance should be set on the basis of a trailing average.	The proposal endorses, as a matter of principle, that a trailing average approach should be used to determine the estimate of the return on debt.	This methodology better reflects the practice of a prudent network operator which is to issue debt at intervals and to maintain a staggered debt portfolio.
Tenor for benchmark debt portfolio: 10 years	Adopts the approach in the Guideline.	There are good reasons for issuing debt with a long term to maturity, and 10 years is the longest tenor that is common in the Australian marketplace.
Credit rating from Standard and Poor's: BBB+	BBB	In both cases, the credit rating is established on the basis of a median of a group of comparator entities, but we would exclude AusNet services from the group on the basis that it is majority government owned.
Form of the transition to a trailing average cost of debt: There would be a transition towards the trailing average over two five-year regulatory periods.	A hybrid approach has been adopted. This makes use of an historical average approach to the measurement of the spread over swap. In addition, swap rates are measured during the	The hybrid approach has been developed to correspond with the debt-raising and hedging practices of privately-owned, regulated distribution businesses.

Guideline	Regulatory Proposal	Rationale
In the first year of the first regulatory period the "on the day" approach would be accorded a 100 per cent weighting. For each of the next 10 years, a weighted average would be calculated in which the weight accorded to the "on the day" approach would be reduced by 10 per cent compared with the year before. In the second year and subsequent years, 10 per cent of the weighted average would be drawn from the prevailing cost of debt in that year, and this figure would then contribute a 10 per cent weighting in each of the next nine years until in year 10, there would be a 10 per cent weighting assigned to each of the 10 most recent years.	averaging period. Swap rates for different tenors are combined.	
Source of third party data for the cost of debt used in historical calculations: 50 per cent RBA corporate bond spreads, Table F3 50 per cent Bloomberg BFV or BVAL curve for BBB rate bonds	The historical values for the spread-to-swap used in the assessment of the hybrid approach to the trailing average will draw upon the reported, past values from the Bloomberg BFV curve, and the RBA measures of corporate bond spreads. An average will be taken of the results from both indicator series.	The two third party indicator series provide reasonable historical data.
Source of third party data for cost of debt calculations during prospective averaging period: 50 per cent RBA corporate bond spreads, Table F3 50 per cent Bloomberg BVAL curve for BBB rate bonds	Third party estimates of the cost of debt will be subject to extrapolation. Different methods will be applied to the task. The extrapolated results will be tested against market data. Results will be chosen from the third party data source that performs best when tested against the underlying market data that is observed or recorded over the relevant reference period.	On a number of previous occasions, the figures quoted by various services have diverged significantly from the underlying market data and with "set and forget" annual updating there is no safeguard against such divergences. To make better use of the observed bond data, yield curves and par yield curves will also be estimated.
Nomination of averaging periods for the cost of debt. The AER requires averaging periods to be nominated for each of the constituent years of the regulatory period. Specifically: The period must be specified prior to the commencement of the regulatory control period. • At the time the period is nominated, all dates in the averaging period must take place in the future. • The averaging period should be as close as practical to the commencement of each regulatory year in a regulatory control period. • A period needs to be specified for each regulatory year within a regulatory control period.	Averaging periods will be nominated in advance. However, we do not propose to choose the periods for all future years before or during the first regulatory year of the new regulatory control period.	We do not believe that there is merit in selecting reference periods for time intervals which may be four or five years hence.

Guideline	Regulatory Proposal	Rationale
The length of the averaging period and timing of when it occurs. An averaging period of 10 or more days should be used. The period should be nominated in advance, but the days should be chosen so as to leave minimal time between the averaging period *per se*, and the commencement of each regulatory year in a regulatory control period.	For clarity, we propose to choose averaging periods prospectively, covering time intervals which have not already lapsed.	

Source: UE, *Rate of Return on Debt: Proposal for the 2016 to 2020 Regulatory Period*, prepared by United Energy, April 2015.

13.6. Debt raising costs

Incenta has evaluated the debt-raising costs for a benchmark business with our characteristics. The methods that were applied by Incenta have been extensively tested, and have also been amended recently in response to the AER's draft decisions for regulated businesses in NSW[67]. Incenta has provided estimates of the direct, "levelised" debt-raising costs which have been expressed in terms of basis points per annum on regulatory debt. The reference to "levelised" essentially means that a form of discounting has been applied. The components of debt-raising costs have been summarised as follows:

- 9.1 basis points per annum for the costs of issuing the bonds in respect of an assumed debt portfolio of $1,242 million. This estimate of the value of our debt is based on the benchmark gearing ratio of 60 per cent, and the projected value of the regulatory asset base, in 2016, of $2,070 million;
- 7.8 basis points per annum to establish and maintain bank facilities that are required to meet the liquidity criteria which have been set out by Standard and Poor's in a proprietary report[68]. The fulfilment of the criteria condition is a necessary condition for the maintenance of an investment grade credit rating; and
- 3.1 basis points per annum to meet the estimated costs of re-financing debt at least three months before the debt matures. The costs of early re-financing are equivalent to the expenses that might be incurred in maintaining a liquidity reserve. Standard and Poor's stipulates that debt issuers with an investment grade credit rating should re-finance bonds three months ahead of expiry[69].

The summation of the components described above provides an estimate of debt raising transaction costs of 20.0 basis points per annum, to be applied to the regulatory value of debt. Incenta has explained that the "levelisation" occurs by calculating the net present value (NPV) of transactions' costs over the regulatory period, and then dividing by the NPV of the Regulatory Asset Base values determined for the same period. The nominal vanilla WACC of 7.38 per cent that we have proposed was used in the calculations.

The method for estimating the benchmark, debt-issuing transactions' cost allowance draws in part on an approach that was described by the Allen Consulting Group (ACG) in a report prepared for the Australian Competition and Consumer Commission[70]. Incenta has progressively refined the detailed implementation of the method. Furthermore, in a report prepared for the Energy Networks Association, (ENA), in June 2013, PWC demonstrated that it had sourced significant new data on the components of bond issuance transactions' costs[71].

[67] See, for instance: AER (November, 2014a), Draft decision – TransGrid transmission determination 2015-16 to 2017-18, Attachment 3: Rate of return; AER (November, 2014b), Draft decision – Jemena Gas Networks (NSW) Ltd Access Arrangement 2015-20, Attachment 3: Rate of return; AER (November, 2014c), Draft decision – ActewAGL distribution determination, Attachment 3: Rate of return.

[68] Standard & Poor's (2014), *Methodology and Assumptions: Liquidity Descriptors for Global Corporate Issuers*, discussed in:

Incenta (2015), Report on debt-raising transaction costs, prepared for United Energy by Incenta Economic Consulting, March 2015; section 4.2.1

[69] Incenta (2015), Report on debt-raising transaction costs, prepared for United Energy by Incenta Economic Consulting, March 2015; section 4.3.

[70] ACG (December, 2004), Debt and equity raising transaction costs, Report to the Australian Competition and Consumer Commission, prepared by the Allen Consulting Group.

[71] PWC (2013), Debt financing costs, prepared for the Energy Networks Association by PWC, June 2013.

Table 13-9: Total debt raising transaction costs

	2016	2017	2018	2019	2020
Debt raising transaction costs ($M, Real 2015)	1.1	1.2	1.3	1.4	1.5
Liquidity – commitment fee ($M, Real 2015)	1.2	1.2	1.1	1.1	0.9
Three month ahead financing costs ($M, Real 2015)	0.4	0.4	0.4	0.5	0.4
Total debt raising transaction costs ($M, Real 2015)	**2.7**	**2.9**	**2.9**	**3.1**	**2.8**
Debt raising transaction costs (bppa)	9.1	9.1	9.1	9.1	9.1
Liquidity – commitment fee (bppa)	9.4	9.1	7.8	7.0	5.6
Three month ahead financing costs (bppa)	3.5	3.3	2.8	3.5	2.4
Total debt raising transaction costs (bppa)	**22.0**	**21.4**	**19.7**	**19.6**	**17.1**
Levelised debt raising transaction costs (bppa)	20.0				

Source: Report on debt-raising transaction costs, prepared for United Energy by Incenta Economic Consulting, March 2015; see Table 11. Note that the year-by-year results for debt-raising costs shown here will not coincide exactly with the year-by-year estimates of debt-raising costs that are produced by the post-tax revenue model. This is because the PTRM starts off with a single input value, being the levelised debt-raising transaction costs, reported above in basis points per annum. The PTRM does not use the profile of the expenditures over five years that was developed by Incenta.

In the post-tax revenue model, our debt-raising transaction costs are shown to increase progressively over time. That is because the PTRM applies a single number for "levelised" debt-raising transaction costs (measured in basis points) to each of the prospective years of the regulatory period. The growth in the regulatory asset base causes debt raising costs to increase. In contrast, in the preparatory analysis undertaken by Incenta, certain components of the costs are presumed to be incurred closer to the start of the regulatory period. Thus, in Table 13-9 above, the distribution of liquidity commitment fees and three month ahead financing costs is skewed towards the early years of the regulatory period.

13.7. Equity raising costs

We have followed the approach to the calculation of equity raising costs that is set out in the new post-tax revenue model, and associated documentation. In addition, we have rolled forward the capitalised equity raising costs from the current regulatory period.

The value of capitalised equity raising costs transferred over from the 2011 to 2015 regulatory period is equal to $3.73 million ($M Real 2015). These capitalised costs are treated as a fixed asset and have been carried forward from the 2011 to 2015 period using the Roll Forward Model.

In addition, the AER's Post-Tax Revenue Model calculates equity raising costs based on the projected requirements for equity funds. The calculation of equity raising costs is, of course, undertaken in a dedicated worksheet in the current version of the Post-Tax Revenue Model promulgated by the AER[72]. We have assessed that total equity raising costs over the 2016 to 2020 regulatory period will amount to $3.43 million ($M Real 2015). In the AER's Post-Tax Revenue Model, the assessed equity raising costs are treated as forecast capital spending, and are therefore added to the Regulatory Asset Base, and are also progressively depreciated. The standard life for equity raising costs has been set at 35 years.

In short, the newly assessed equity raising costs are added to the "legacy" equity raising costs that have been brought over from the previous regulatory period, after appropriate price level adjustments have been made.

[72] AER, Final decision, Amendment, Electricity distribution network service providers, Post-tax revenue model handbook, 29 January 2015.

We also propose to undertake annual updates to the calculation of equity raising costs in each successive year of the forthcoming regulatory period. The Post-Tax Revenue Model is configured to perform revenue smoothing calculations and equity raising cost updates manually via buttons that will trigger built in macros. As the AER has reported, the estimate of equity raising costs is dependent on the smoothed revenue (or expected revenue) profile, but, in turn, the expected revenue is dependent on the estimate of equity raising costs[73]. This is because a change in the equity raising cost will change the annual revenue requirement (ARR), and expected revenue, which, in turn, will alter the equity raising cost. Therefore, equity raising costs will be iteratively updated while smoothing takes place.

13.7.1. Assumptions which underpin the AER's method for assessing equity raising costs

In a submission to the AER provided in November 2014, we reported that the AER had maintained its previous values for dividend re-investment plan costs, subsequent equity raising costs, and dividend re-investment plan take-up rates[74]. Dividend re-investment plan expenses have been worked out, using the benchmark "DRP" cost of one per cent as applied to the dividend reinvestment plan requirement, while the external equity raising cost is now only computed for the difference between the equity requirement and dividend reinvestment. The benchmark seasoned equity offering (SEO) raising cost is still set at three per cent.

The following variables should therefore be subject to review:

- The assumption of a one per cent cost for a dividend reinvestment plan;
- The size of the direct cost allowance of three per cent for SEOs; and
- The rate at which dividends are assumed to be re-invested (currently set at 30 per cent).

The 'Equity raising cost' worksheet makes use of net capex figures, i.e. capital expenditure minus the level of customer contributions. Since net capital spending is invariably lower than gross capital spending, the requirement to raise new equity will be shown as being less than it would otherwise be.

An offsetting factor, however, is that customer contributions affect the estimate of taxable income in the Post-Tax Revenue Model (essentially pushing it up). Dividends are then computed by grossing up the estimate of tax payable. The payment of dividends to shareholders creates the need for new equity to be raised. The taxation of customer contributions generates franking credits, the presence of which is meant to give rise to a second round need for dividends.

A review of the framework for equity raising costs should consider, *inter alia*:

- The additional dividend distributions that need to be made so that shareholders can realise the benefits from gamma; and
- The complementary capex that might be required to match a certain level of customer contributions.

The AER responded to our submission by acknowledging that the ERC input variables should be updated from time to time[75]. The AER also expressed an opinion that the ERC calculation is correct to consider net capex (after deducting capital contributions) as the relevant cash flow. The AER stated that it is not the gross capital spending for which the service provider needs to raise funds, but rather the net capital spending, with customers contributing the difference.

We do not believe that the matter of the treatment of customer contributions, when assessing the requirement to raise new equity, has been addressed correctly. A fuller consultation would consider a more holistic treatment of customer contributions.

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[73] AER, Final decision, Amendment, Electricity distribution network service providers, Post-tax revenue model handbook, 29 January 2015, page 28.

[74] UEMG, *Submission to the AER's consultation on the post-tax revenue mo*del, 17th November 2014.

[75] AER, Amendment, Electricity transmission and distribution network service providers, Post-tax revenue models (version 3), 29 January 2015, page 13.

14. Estimated cost of corporate income tax

Key messages:

- The estimation method that we propose will result in an estimate of gamma that reflects the value which equity-holders place on imputation credits. In particular, we propose to calculate gamma in the orthodox manner, by applying the Monkhouse formula[76], which states that gamma is the product of:
  - The distribution rate, which refers to the extent to which imputation credits that are created when companies pay tax, are distributed to investors; and
  - The value of distributed imputation credits to investors who receive them (theta). Theta can be estimated using dividend drop-off analysis which uses the movements in share prices around ex-dividend days to infer a valuation for imputation credits. However, there are also other empirical approaches that can be used to infer a value for theta.
- We propose to use an observed distribution rate (0.7), which is consistent with the AER's Rate of Return Guideline, (the Guideline), and previous findings of the Australian Competition Tribunal (the Tribunal)[77]. We propose that the distribution rate be combined with the best estimate of theta from market value studies (0.35), which leads to an estimate for gamma of 0.25. This proposal is consistent with the expert advice of Professor Stephen Gray[78]. We consider that the AER's recently developed methods fail to estimate gamma in such a manner as to represent the value that equity-holders place on imputation credits.

Further information about the value of imputation credits, beyond that presented in this Regulatory Proposal, is available in a separate appendix that addresses the latest analytical developments on gamma[79].

14.1. Appropriate interpretation of the value of imputation credits

Clause 6.5.3 of the Rules requires an estimate of γ (gamma), being “the value of imputation credits”.

We consider that the words “value of imputation credits” have a clear and unambiguous meaning. We consider that the reference to a value of imputation credits is clearly denoting the value to equity-holders of imputation credits that are distributed by the business. The AER has suggested in the Guideline that “value” could “be used in a generic sense to refer to the number that a particular parameter takes (that is, its numerical value)” [80]. If the word “value” were being used in that sense, then the appropriate phrase would be the “value for imputation credits”. Such a phrase would be meaningless and would provide no assistance in construing the meaning of gamma. In contrast, the use of the words “value of” indicates that the term has its ordinary meaning — the value of something is its worth. The interpretation in the Guideline clearly is an incorrect interpretation of the Rule. To apply that incorrect interpretation of the Rule would involve legal error. However to the extent that there are possible alternative interpretations of the words “value of imputation credits”, the NEL requires that the interpretation that will best achieve the purpose or object of the NEL is to be preferred over any other interpretation[81].

The object of the NEL 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[82]. The relevant

[76] P. H. L. Monkhouse, ‘Adapting the APV valuation methodology and the beta gearing formula to the dividend imputation tax system’, Accounting and Finance 37 (1997) 69–88, at 72, 74. See also: Monkhouse (1996) and Monkhouse (1993).

[77] Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9, [22].

[78] SFG, Estimating gamma for regulatory purposes, February 2015.

[79] UE, Assessment of the value of imputation credits: Proposal for 2016 to 2020, prepared by United Energy, April 2015.

[80] AER, Better Regulation, Explanatory Statement, Rate of Return Guideline, Appendices, December 2013; Appendix H, page 150.

[81] NEL, Schedule 2, item 7(1), NEL.

[82] NEL, Schedule 7.

secondary materials make clear that the NEO is 'an economic concept', which, at its core, seeks to promote economic efficiency. The second reading speech accompanying the introduction of the NEO states:

> "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." [83]

Accordingly, to the extent that the words "value of imputation credits" could be susceptible to more than one meaning, the meaning that is more likely to promote economically efficient investment in, and use of, electricity services should be preferred.

We consider that in order to promote efficient investment in, and use of, electricity services, the words "value of imputation credits" must be interpreted as the value to equity-holders of imputation credits that are distributed by the business. In the context of determining an adjustment to the corporate income tax building block to account for imputation credits, what is relevant is the value that equity-holders place on those credits, because the value has an effect on the overall return that they receive on their investment, and may potentially provide incentives to undertake efficient investment. If the value for gamma is set higher (or lower) than the actual value to investors of imputation credits, then the discount that is applied to the tax building block will over-state (or under-state) the value to investors of imputation credits, meaning that overall after-tax returns will be too low (or too high). Thereafter, there could be over or under investment. The following simple example helps to illustrate the point. If investors require an annual after-tax return of $70 to invest in a particular business, the level of pre-tax return that is required to promote efficient investment would be $100, if there is no value assigned to imputation credits. However, if investors assign a positive value to imputation credits, then the level of pre-tax return that is required to promote efficient investment would be somewhat less than $100, depending on how much value is assigned to those credits. For example, if investors apportion a value to credits representing 25 per cent of the total face value of all credits generated by the business (gamma of 0.25), then the required pre-tax return would be reduced to $90.32. This value is worked out as:

$$Required\ return = 100 \times \left[1 - \left(\frac{\gamma r_t}{1 - r_t(1-\gamma)}\right)\right] = 100 \times \left[1 - \left(\frac{0.25 \times 0.3}{1 - 0.3(1 - 0.25)}\right)\right] = \$90.32 \qquad (1)$$

Where:

r_t = rate of corporate tax (30%)

γ = value of a distributed imputation credit (0.25)

Table 14-2 below illustrates the implication of assigning a value to imputation credits which does not reflect the value actually placed on credits by investors in the business. Clearly, if the value that is assigned to gamma is higher than the value actually placed on credits by investors in the business, then the level of pre-tax returns will be below what is required to promote efficient investment.

[83] South Australia, Parliamentary Debates, Legislative Council, 2nd March 2005, 1303 (P Holloway).

Table 14-1: Example of gamma impact on overall returns ($)

	Required returns, based on actual value of imputation credits to investors (assume value of 0.25)	Required returns, based on higher value of imputation credits to investors (assume value of 0.5)
Required post-tax return	70.00	70.00
Company tax	27.10	24.71
Less: value of imputation credits to investors	6.77	12.35
Required pre-tax return	90.32	82.36

Source: Calculations by United Energy.

There is therefore an imperative for the value of gamma to accurately reflect the value of imputation credits to investors, rather than represent the face value of the credits, or the rate at which the credits are redeemed. This is the only interpretation of the term 'gamma' which properly gives effect to the statutory objective of promoting efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers. Any other approach would result in the business not being properly compensated for the overall return required by investors, which would in turn lead to inefficient investment.

This approach to interpretation is consistent with the approach taken with other elements of the return on capital. For example, the return on debt is estimated by reference to the returns actually required by investors, as reflected in market prices for the relevant securities. Consistent with this, any offsetting adjustment to the overall return received by investors to account for imputation credits must reflect the value actually ascribed by investors to those imputation credits, not their notional maximum value or nominal face value.

14.2. Gamma and the redemption rate

The National Electricity Rules and National Gas Rules state that: [84]

> 'γ is the value of imputation credits'

and the AER, in its *Draft decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015-20*, relies on Officer (1994) for an interpretation of what is meant by the value of imputation credits. [85] The AER, for example, states that: [86]

> 'Our approach to interpreting and estimating the value of imputation credits is guided in the first instance by the conceptual framework developed by Officer.'

While Professor Robert Officer of the University of Melbourne is a natural authority to whom to turn, extracting an interpretation from his 1994 paper is complicated by the fact that in that paper he defines gamma to be two quantities that will in general differ. In his 1994 paper, Officer defines gamma to be both:

- The proportion of credits created that are redeemed; and
- The value of a dollar of tax credits created to a representative shareholder.

In general, gamma should be interpreted as the value of a dollar of tax credits created to a representative shareholder and not the proportion of credits created that are redeemed. Imputation credits created can only raise

[84] Australian Energy Market Commission, *National Electricity Rules Version 69*, page 661.
Australian Energy Market Commission, *National Gas Rules Version 25*, page 63.

[85] Officer, Robert R., *The cost of capital of a company under an imputation tax system*, Accounting and Finance, 1994, pages 1-17.

[86] AER, *Draft decision Jemena Gas Networks (NSW) Ltd Access arrangement 2015–20 Attachment 4 - Value of imputation credits*, November 2014, page 34.

the value of a firm if credits distributed by the firm will cut its cost of equity. The extent to which the firm's cost of equity will be cut will be determined by the extent to which the firm distributes credits created and by the value placed on a dollar of credits distributed by a representative shareholder. [87]

In a small, open economy – like Australia – the proportion of credits created that are redeemed is likely to exceed by a substantial margin the value of a dollar of tax credits created to a representative shareholder. Thus, an estimate of the proportion of credits created that are redeemed is unlikely to provide an unbiased estimate of the value of a dollar of tax credits created to a representative shareholder.

In general, however, the value placed by a representative investor on a dollar of tax credits created will not exceed the proportion of credits created that are redeemed. Thus, an estimate of the proportion of credits created that are redeemed can be viewed as an estimate of an upper bound on the value of a dollar of tax credits created to a representative shareholder.

The value of a dollar of tax credits created can be viewed as the product of the rate at which credits created are distributed – the distribution rate – and the value of a dollar of tax credits distributed – theta.

There will only be a single value for theta – the value that a representative investor places on a dollar of tax credits distributed. The value that the representative investor places on a dollar of tax credits distributed by one firm will not differ from the value that the investor places on a dollar of tax credits distributed by another firm. Thus, theta is not a firm specific parameter.

The distribution rate, on the other hand, is a firm specific parameter. [88] One firm, after weighing up the costs and benefits of distributing credits, may decide to distribute all of the credits that have been created over a particular period. A second firm may rationally decide to distribute no credits – perhaps because it wishes to use internally generated funds to finance new projects.

As theta should not vary from firm to firm, however, there should be no link between how one estimates theta and how one estimates the distribution rate.

14.3. Summary of arguments about gamma

The Rules require an estimate of "the value of imputation credits" (also referred to as "gamma") as an input to the calculation of the corporate income tax building block. In order to promote the NEO, the estimate of gamma must reflect the value that equity-holders place on imputation credits (as opposed to simply their face value or utilisation rate). This is because, although gamma is an input into the corporate income tax calculation, the value adopted for gamma ultimately has a role in determining returns for equity-holders. If the value ascribed to imputation credits is higher than the value that equity-holders place on credits, then 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.

The estimation method that the AER proposes to adopt will not result in an estimate of gamma that reflects the value that equity-holders place on imputation credits. The AER's method involves the following critical errors:

- The AER's revised definition of theta – which seeks to exclude the effect of certain factors on the value of imputation credits – is conceptually incorrect and inconsistent with the requirements of the Rules;
- The AER incorrectly uses equity ownership rates as direct evidence of the value of distributed credits (theta). In fact, 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. Theta can be no higher than the equity ownership rate and will, in fact, be lower due to factors which reduce the value of credits distributed to Australian investors;
- The AER has erred in its interpretation of the equity ownership data – the ranges used by the AER for the equity ownership rate are inconsistent with the evidence that was presented by the AER in its recent draft decisions[89];

[87] We mean by the cost of equity, the cost of equity conventionally defined – that is, exclusive of a value assigned to imputation credits distributed.

[88] The distribution rate is also known as the payout ratio.

[89] See, for instance: AER, Draft decision, Jemena Gas Networks (NSW) Ltd, Access arrangement 2015–20, Attachment 3: Rate of return, November 2014.

- The AER uses redemption rates as direct evidence of the value of distributed credits (theta), when, in fact, redemption rates are no more than an upper bound (or maximum) for this value;
- 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;
- The AER has erred in its interpretation of market value studies. The AER considers market value studies in a very general manner, rather than considering the merits of the particular market value estimate we proposed. This is an irrational and unreasonable approach to considering the evidence put forward in relation to the market value of imputation credits;
- In addition to (correctly) observing that the market-wide distribution rate is 0.7, the AER has relied on a higher estimate of the distribution rate for listed equity only. Given that data on the distribution rate is available for all equity, it is neither necessary nor appropriate to separately identify a distribution rate for listed equity only based on a limited sample; and
- The AER's ultimate conclusion as to the value for gamma is generally inconsistent with the evidence presented in the draft decisions of November 2014[90]. The conclusion is also at odds with the AER's own analysis of the equity ownership rate and redemption rate, with both of these measures showing that the AER has overestimated the value of imputation credits.

A fundamental question which the AER must consider is what impact the distribution of credits by a company will have on the company's cost of equity, and what impact the distribution of credits by companies in general will have on the cost of equity for the domestic market as a whole. To respond to these queries necessitates that one compare the cost of equity that will prevail when credits are distributed to the cost of equity that would prevail were no credits to be distributed. Determining the difference between these two costs of equity is not a straightforward task because the shareholdings of domestic and foreign investors will depend on whether credits are distributed. One cannot, for example, determine the difference between the cost of equity that will prevail when credits are distributed and the cost of equity that would prevail were no credits to be distributed simply by measuring the fraction of credits that are redeemed from tax statistics. This is because domestic investors who redeem credits would be likely to place a smaller fraction of their wealth in domestic equities were no credits to be distributed, and because foreign investors would be likely to place a larger fraction of their wealth in domestic equities.

Even if all credits were currently redeemed by domestic investors, one could still not determine the difference between the cost of equity that will prevail when credits are distributed to the cost of equity that would prevail were no credits to be distributed by measuring the fraction of credits that are redeemed from tax statistics. This is because foreign investors who may not hold domestic equities when credits are distributed might well hold domestic equities were no credits to be distributed. The tax statistics compiled by the Australian Taxation Office (ATO) cannot, by construction, provide information about the characteristics of potential holders of domestic equities. These potential holders of domestic equities, however, can play an important role in determining what impact the distribution of credits will have on the cost of equity.

The correct approach to estimating gamma has been set out in a separate stand-alone document which accompanies this Regulatory Proposal[91]. The method involves estimating the distribution rate using ATO data and estimating theta based on the value of imputation credits reflected in share price movements (i.e. using dividend drop-off analysis). Combining the observed distribution rate (0.7) with the best estimate of theta from market value studies (0.35) leads to an estimate for gamma of 0.25. The AER should also have regard to other high quality market valuation studies, including those which estimate the relationship between imputation credits and equity returns[92].

[90] See, for instance: AER, Draft decision, Jemena Gas Networks (NSW) Ltd, Access arrangement 2015–20, Attachment 3: Rate of return, November 2014.

[91] UE, *Assessment of the value of imputation credits: Proposal for 2016 to 2020*, prepared by United Energy, April 2015.

[92] NERA (2013), Imputation Credits and Equity Prices and Returns, A report for the Energy Networks Association, prepared by NERA Economic Consulting, October 2013.

14.4. Gamma and the post-tax revenue model

In a recent submission to the AER's consultation on the new post-tax revenue model, Hathaway (2014) examines the manner in which imputation credits are accrued and then paid out[93]. The Post-Tax Revenue Model incorporates a structure for the measurement of cash flows and the payment of corporate taxes[94]. Hathaway reports that a major problem with the Post-Tax Revenue Model is its presumption that imputation credits can be paid out even when there are no funds available to distribute dividends, *per se*.

A further shortcoming of the Post-Tax Revenue Model is its assumption that franking credits created at a certain point in time are valued at their market value at that time irrespective of whether they are paid in the particular year. As reported by Hathaway, such a presumption is comparable to a belief that franking credits will increase in value over time, as a function of the return on equity, and will then be discounted back at the cost of equity to obtain the current value[95].

The franking account balances of all companies, (FAB), represent the tax payments that companies have made to government minus the tax that has been distributed to shareholders, (other than other companies), as franking credits passed on in conjunction with franked dividends.

The FAB, in theory, represent franking credits that might be accessed in the future. However, the credits would only be available as part of a future franked dividend. If shareholders have a negative cash flow and do not receive a dividend, then any credits created by company tax payments accumulate to the FAB until such time as a franked dividend can be paid. Importantly, franking credits retained in the FAB are fundamentally different to earnings retained by the company. Imputation credits do not earn any return when retained within the FAB, and are therefore a wasting asset. The FAB, after all, reflects net tax paid to government, and is an accounting record.

In summary, the Post-Tax Revenue Model is mistakenly assuming that a retained franking credit is of equal value to a distributed credit.

Hathaway also reports an inconsistency within the Post-Tax Revenue Model in terms of the use of annual updating for the cost of debt, versus a 55-year geometric average of the tax rates.

14.5. Method for calculating corporate income tax

Section 6.5.3 of the Rules requires the estimated cost of corporate income tax to be calculated for each regulatory year in accordance with the formula:$ETC_t = (ETI_t \times r_t)(1 - \gamma)$

Where:

ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services if such an entity, rather than the DNSP, operated the business of the DNSP, such estimate being determined in accordance with the post-tax revenue model;

r_t is the expected statutory income tax rate for that regulatory year as determined by the AER; and

γ is the value of imputation credits.

For these purposes:

- The estimate of the pre-tax income must be fundamentally based on that of a benchmark efficient DNSP; and
- The estimate must take into account the estimated depreciation for that regulatory year, for tax purposes, of a benchmark efficient DNSP. The value of the assets of the service provider is presumed to be included in the regulatory asset base for the relevant distribution system for that regulatory year.

A key element of the above Rules is that the allowance for tax must be for the provision of standard control services by the 'benchmark efficient entity'.

93 Hathaway (2014), Comments on the AER's post-tax revenue model, A submission prepared for United Energy and Multinet Gas by Neville Hathaway, Capital Research Pty Ltd., December 2014.

94 AER (2014), Proposed amendment, Electricity distribution network service providers, Post-tax revenue model handbook, October 2014.

95 Hathaway (2014), Comments on the AER's post-tax revenue model, A submission prepared for United Energy and Multinet Gas by Neville Hathaway, Capital Research Pty Ltd., December 2014; page 7.

Differences arise between these regulatory concepts and actual tax filings because the filings concern real businesses with a different range of activities. We have determined the estimate of corporate tax, ETC_t, by applying the AER's post-tax revenue model.

14.6. Calculation of corporate income tax allowance

We have applied the AER's Roll Forward Model to assess the progression of the tax asset base over the current regulatory period, from January 2011 to December 2015. The method used for determining the opening tax asset base in January 2016, in the current Roll Forward Model, is consistent with the method that was used by the AER to perform tax asset calculations in the Post-Tax Revenue Model for 2011 to 2015. The classification of assets in the tax asset base of the Roll-Forward Model, as at January 2016, corresponds with the classification of assets in the Regulatory Asset Base.

In the Post-Tax Revenue Model for the forthcoming regulatory period, there is a similar alignment between the classification of assets in the tax asset base and in the regulatory asset base. A straight line method of depreciation has been used in the Tax Asset Base, consistent with the method that has already been adopted for the Regulatory Asset Base.

The AER's Post-Tax Revenue Model calculates tax depreciation on a straight line or "prime cost" method. Under this method, the original cost of the asset is depreciated over the effective life of that asset for tax purposes, which generally gives rise to the same amount of depreciation deductions in each year for that asset. In the AER's Post-Tax Revenue Model, forecast capex is treated in a comparable manner in the sense that it is depreciated on a straight line method over the effective life of the asset for tax purposes.

In order to produce tax standard lives, information was sourced from tax rulings published by the ATO, the most pertinent ruling being TR 2014/4 from July 2014. A process was adopted to combine the lives for published tax asset categories into effective groupings which corresponded with the tax asset base categories in the AER's Post-Tax Revenue Model. In effect, weighted average standard asset lives were determined for the broad, higher level categories that are represented in the 'Inputs' worksheet of the Post-Tax Revenue Model. The discussion which accompanies Table 14-2 explains the rationale for the approach, and refers to the other data sources used.

Tax remaining lives were calculated after making use of the existing information on Regulatory Asset Base standard lives and Regulatory Asset Base remaining lives. The preferred approach was to set the remaining lives of assets in the tax asset base categories to be equal to the remaining lives used in the corresponding Regulatory Asset Base categories.

Table 14-2: The calculation of weighted average tax standard lives nominal

ATO Tax Asset Descriptions	ATO lives	Economic Benchmarking Categories	AER Post-Tax Revenue Model Regulatory Asset Base categories	Weighted average tax standard lives
Above ground (incorporating conductors; cross arms, insulators and fittings; poles – concrete, wood, steel or stobie; and transformers – pole or ground pad mounted)	45.0	Overhead distribution assets less than 33kV (wires and poles)	Distribution System Assets	46.0
Underground (incorporating cables, fittings and ground pad mounted transformers)	50.0	Underground distribution assets less than 33kV (cables, ducts etc.)		
Distribution substations/transformers, pole or ground pad mounted	40.0	Distribution substations including transformers		
Transmission lines (incorporating conductors, insulators and towers)	47.5	Overhead assets 33kV and above (wires and towers / poles etc.)	Sub-transmission Assets	45.0
		Underground assets 33kV and above (cables, ducts etc.)		
Distribution zone substations (excluding control, monitoring, communications and protection systems)	40.0	Zone substations		
Non-network general assets - Other	8.0	Cars (motor vehicles designed to carry a load of less than one tonne and fewer than 9 passengers): General	Non-network general assets - Other	12.0
	12.0	Light commercial vehicles designed to carry a load of one tonne or greater and having a gross vehicle mass of 3.5 tonnes or less		
	15.0	Trucks having a gross vehicle mass greater than 3.5 tonnes (excluding off highway trucks used in mining operations)		

Source: ATO (2014), Tax Ruling, TR 2014/4, Australian Taxation Office, July 2014. AER, Economic benchmarking RIN for 2013, completed by United Energy.

The tax asset lives that were sourced from the ATO were inserted into Table 14-2 as shown above. The ATO tax asset categories, for which the lives were collected, appeared to offer an approximate concordance back to the regulatory asset base categories. The results from the economic benchmarking regulatory information notice (RIN) were also used to devise weights to apply to the tax standard lives. The most relevant variable to consider from the economic benchmarking RIN was capex, presented according to economic benchmarking categories. When the capex based weights were applied to the ATO tax asset lives, presented for different types of electricity network assets, weighted average tax standard lives were produced, and these have been reported in Table 14-2. The tax standard lives have been employed in the Post-Tax Revenue Model.

The components of the cost of corporate income tax calculation are presented in the Post-Tax Revenue Model and Roll Forward Model as part of this Regulatory Proposal.

15. Incentive schemes

Key messages:

- We accept the application of the AER's incentive schemes, subject to proposed changes to the Service Target Performance Incentive Scheme and to the Victorian Government's F-factor Scheme being applied in its amended form.

15.1. Efficiency benefit sharing scheme

In its Framework and Approach paper, the AER explained that its revised Efficiency Benefit Sharing Scheme (EBSS) will apply in the forthcoming regulatory period[96]. The objective of the EBSS is to provide a fair sharing of efficiency gains and losses with our customers. In addition, it provides us with a consistent incentive to deliver efficiency improvements throughout the five-year regulatory period.

In calculating our EBSS for the forthcoming regulatory period, we have started the scheme by measuring actual versus benchmarks from 2011. This is consistent with the AER's Final Determination for the current regulatory period, where it set our Efficiency Carryover Mechanism to zero.

We support the continuing application of the EBSS. As a commercially focused company, we have responded to the incentives provided by this scheme. As a consequence, our customers are now enjoying the lowest cost distribution services in the NEM. Given this experience, it is important that the AER continues to apply the EBSS in a manner that rewards those companies that deliver efficiency gains.

15.2. Capex efficiency sharing scheme

We accept the AER's Version 1 of the scheme published in November 2013.

15.3. Service target performance incentive scheme

15.3.1. Parameters of scheme

The AER's Service Target Performance Incentive Scheme (STPIS)[97] provides a financial incentive for DNSPs to improve service performance. The principal rationale for the STPIS is to ensure that DNSPs do not achieve cost efficiencies at the expense of deteriorating service performance. By rewarding good service performance (and by penalising poor performance), the STPIS provides a counter-balance to the incentives provided by the EBSS and the CESS to deliver cost efficiencies.

The STPIS is part of the building block determination and contains two mechanisms, as explained below:

- The s-factor adjustment to the annual revenue allowance for standard control services; and
- A guaranteed service level (GSL) component composed of direct payments to customers experiencing service below a predetermined level.

For the Victorian DNSPs, however, the GSL component of the STPIS will not apply because they are already subject to a jurisdictional scheme. While we accept the retention of the jurisdictional scheme, we note that the nature and scope of the GSL payments have not been reviewed for many years and adopting the national GSL scheme would be more consistent with best practice regulatory principles.

The AER's Framework and Approach paper sets out its proposed approach in applying the s-factor component of the STPIS as follows:

[96] AER, Efficiency benefit sharing scheme for electricity network service providers, 29 November 2013.

[97] AER, *Electricity distribution network service providers - service target performance incentive scheme*, 1 November 2009.

- Set revenue at risk for each DNSP within the range nominally, ±5 per cent;
- Segment the network according to feeder categories (CBD, urban, short rural and long rural as appropriate for each DNSP) in the Victorian jurisdictional distribution licence conditions;
- Set applicable reliability of supply (i.e. system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI) and momentary average interruption frequency index (MAIFI)) and customer service (telephone answering) parameters;
- Set performance targets based on the DNSPs' average performance over the past five regulatory years; and
- Apply the methodology indicated in the national STPIS for excluding specific events from the calculation of annual performance targets.

While these aspects of the STPIS are proposed by the AER in its Framework and Approach paper, the AER acknowledges that DNSPs can propose variations. Before addressing the case for variations, it is important to address the issues regarding the VCR.

The AER explains that economic analysis of the value customers place on improved service performance (VCR) is an important input to STPIS. VCR studies estimate how willing customers are to pay for improved service reliability as a monetary amount per unit of energy during a supply interruption. VCR estimates are used in the STPIS to:

- Set the incentive rates for each reliability of supply parameter; and
- Weight reliability of supply performance across different segments of the network.

As discussed in section 10.10, the VCR estimates are employed in our investment decision-making. We adopt a probabilistic approach to network investment. This means that we weigh up the benefit to customers of maintaining a reliable network (based on the VCR) and the costs of delivering that maintained reliability. This approach delivers an economically efficient outcome.

Currently, the VCR estimates in the STPIS are taken from studies conducted for the ESCV and the Essential Services Commission of South Australia.[98] These VCR estimates are:

- $95,700/MWh for the CBD; and
- $47,850/MWh for all other segments.

In both cases, the estimates are expressed in 2008 prices, and therefore need to be adjusted to reflect inflation. More recently, AEMO has conducted a new study[99], which estimates the headline Victorian VCR for all sectors and all seasons to be $39,500/MWh, expressed in 2014 prices. This updated estimate is substantially lower than the values specified in the STPIS, and has important implications for how the STPIS should operate in the forthcoming regulatory period. The AER commented on this issue in the following terms[100]:

> "We think it is in the best interests of all parties that an updated VCR be used. This is because it will provide confidence that the true value that customers place on reliability is reflected. Accordingly, we expect to undertake a review of our national STPIS now these studies are complete. However, any change to the STPIS is subject to the distribution consultation procedures in the rules.[101] We consider there is insufficient time to conduct a comprehensive review of the STPIS before the five Victorian electricity DNSPs submit proposals in April 2015 for the forthcoming regulatory period. Therefore our position is to apply the national STPIS in its current form but apply revised values for VCR through the distribution determination. In doing so we will need to consider whether a change in VCR values results in any transitional issues which must be addressed through the STPIS or through the determination. In particular, whether the changed values of VCR should be applied to all investments or only to new investments. If feasible, we will consider conducting

[98] Charles River Associates, *Assessment of the Value of Consumer Reliability (VCR)* – Report prepared for VENCorp, Melbourne 2002; KPMG, *Consumer Preferences for Electricity Service Standards*, 2003.

[99] AEMO, Value of Customer Reliability Review, Final Report, September 2014

[100] AER, Final Framework and Approach for the Victorian Electricity Distributors Regulatory control period, commencing 1 January 2016, 24 October 2014, page 67.

[101] NER, Part G.

> a more thorough review of the STPIS as a parallel process to the determination. We will consider this issue at that time and consult with the five Victorian electricity distributors."

If the Victorian headline VCR using AEMO's 2014 VCR survey is used to forecast Augmentation capex and Replacement capex for power transformers, then customers should expect reduced levels of reliability in future. This is because lower VCR estimates imply reduced levels of network investment compared to the status quo.

Our VCR Guideline (UE GU 2208) sets out the rationale for the VCR values that we have applied in our forecasts for Augmentation capex and Replacement capex for power transformers as well as the risks of the AER substituting a lower VCR value. This is discussed in Chapter 10.

We also note that clause 5.2 of the Victorian Electricity Distribution Code requires us to use our best endeavours to meet, among other things, reasonable customer expectations of reliability of supply. Our feedback from customers is that they expect us to maintain reliability, and do not want reliability to deteriorate. In addition, the capex objectives in the Rules also require us to maintain reliability, in the absence of a regulatory obligation to the contrary[102].

In light of these observations, we set out below two options for how the STPIS should operate in the forthcoming regulatory period depending on the VCR applied to Augmentation capex and Replacement capex for power transformers – Option 1 being our proposed option.

[102] Clause 6.5.7(c).

Table 15-1: STPIS options for the forthcoming regulatory period

	VCR for Augmentation and Power Transformer Replacement capex	STPIS parameters			Forecast outcomes / implications
		VCR	Targets	Revenue at risk	
1.	UE specific VCR using AEMO 2014 VCR survey results calculated on data specific for summer peak period only	Victorian headline VCR using AEMO 2014 VCR survey results calculated on data across all sectors and all seasons (i.e. $39,500/MWh)	Based on five year historical performance, as per the AER Framework and Approach paper	5 per cent, as per the AER Framework and Approach paper	• Reliability maintained - no change in customer experience; no further deterioration for worst served customers • Consistent with customer feedback • Consistent with capex and opex forecasts • No net impact on faults / claims • Net zero STPIS penalties
2.	Victorian headline VCR using AEMO 2014 VCR survey results calculated on data across all sectors and all seasons	Victorian headline VCR using AEMO 2014 VCR survey results calculated on data across all sectors and all seasons (i.e. $39,500/MWh)	Significantly relaxed (i.e. higher) targets, recognising impact of lower capex allowance and VCR. This is required because the VCR is lower in forthcoming regulatory period than it has been in the current period and therefore our capex is proportionately lower.	1 per cent, given uncertainty around transitioning to lower level of reliability	• Reliability deteriorates by 4.2 mins p.a. - more blackouts on hot summer days • Fault response times compromised - outages occurring at same time • Supply restoration times compromised - reduced spare capacity • Inconsistent with capex forecast • Require additional $0.5 million opex over five years in increased faults, emergency maintenance / claims • Higher GSL payments for worst served customers • Only net zero STPIS penalties if targets relaxed – $7-9 million STPIS penalties over period if targets based on five year average

Each of these two options is internally consistent.

Our preference is to adopt Option 1 because it is consistent with:

- Maintaining reliability overall and with no deterioration in reliability for worst served customers – i.e. net zero STPIS position for forthcoming regulatory period;
- Complying with clause 6.5.7(a) of the Rules that forecast capex must “maintain reliability” in the forthcoming regulatory period; and
- Adopting the recommendations in AEMO’s VCR Application Guide.

We have developed our expenditure forecasts, set out in Chapter 10, on this basis.

We do not support Option 2 because:

- The AER would be making a conscious decision that we not supply some customers on hot summer days despite all power system equipment being in service. To highlight the issue is not confined to only a few customers in remote rural areas, Section 4.7 of UE VCR Application Guideline (UE GU 2208) presents a forward looking example of where widespread load shedding (up to 70MW or 20,000 customers) is forecast to occur at a major Melbourne metropolitan terminal station from 2021 if a VCR of $39.50/kWh is used based on current maximum demand forecasts. Section 4.8 present a historical example of where widespread load shedding would have occurred in 2010, 2011 and 2013 (up to 70MW or 20,000 customers) had the VCR of $39.50/kWh been used at the time of the RIT to delay the augmentation that was undertaken in 2009;

- Our consultation with stakeholders reveals that they do not support deteriorating reliability over time;
- We would not be complying with clause 6.5.7(a) of the Rules that forecast capex must "maintain reliability" in the forthcoming regulatory period;
- We are already currently the highest utilised network in the NEM and the resultant decrease in Augmentation capex would not provide sufficient network capacity to avoid overloading the system during peak summer conditions; and
- We would be prolonging the period of poor reliability for our worst served customers.

The performance targets based on Option 1 are set out in Table 15-2 below.

Table 15-2: STPIS targets

Description	2016	2017	2018	2019	2020
Unplanned SAIDI					
– Urban	62.6	62.6	62.6	62.6	62.6
– Rural Short	162.4	162.4	162.4	162.4	162.4
Unplanned SAIFI					
– Urban	0.92	0.92	0.92	0.92	0.92
– Rural Short	2.16	2.16	2.16	2.16	2.16
MAIFI					
– Urban	0.94	0.94	0.94	0.94	0.94
– Rural Short	3.19	3.19	3.19	3.19	3.19

15.3.2. Variation to Reliability Definitions

As set out in our July 2014 submission on the AER's Preliminary Positions Framework and Approach paper, we support the AEMC's September 2014 Final Report Review of Distribution Reliability Measures[1], as explained below.

Momentary interruption Events

The AEMC proposed that Momentary Average Interruption Frequency Index event (MAIFIe) is a preferred measure of momentary reliability performance, compared to the MAIFI. While the MAIFI measure includes every device operation (circuit breaker and automatic circuit recloser) where supply is restored within one minute, the measure of MAIFIe groups momentary interruptions into individual events. While the AER's STPIS currently specifies MAIFI, Victorian networks have traditionally reported, and been rewarded and penalised against MAIFIe.

The use of MAIFIe could encourage distribution networks to optimise reclose operations to improve network reliability. Customers are therefore likely to benefit from improved restoration outcomes, although they may be more aware of multiple restoration attempts. We support the continued use of MAIFIe in Victoria for the same reasons

[1] Found at: http://www.aemc.gov.au/getattachment/792bdac4-bfec-45a4-9a95-d4cc8f710db7/Final-Report.aspx

set out in the AEMC's Report, being that it will promote investment in distribution automation systems, and hence improve reliability for many customers.

Duration of interruptions

The AEMC's Review considered whether the duration of momentary interruptions should remain unchanged (less than 1 minute) or be changed to conform to the *IEEE 1366 - 2012* standard of less than five minutes or the UK/European standard of less than three minutes.

We support the AEMC's Report that three minutes is appropriate based on the available technology and network operational requirements. To align the duration of momentary interruptions with sustained interruptions means the duration of sustained interruptions would be greater than three minutes. This change in duration will need to be reflected in the AER's STPIS.

Major event days and catastrophic events

Under the current STPIS and benchmarking arrangements, major event days are excluded from the calculation of distribution reliability measures, on the basis of statistical analysis. The AER currently requires a distribution network to use the 2.5 beta (β) method in identifying major event days, where β is the standard deviation of a normal distribution, and the value of β can vary across networks.

The IEEE has noted that rare, but severe, events such as cyclones, floods and bushfires can distort the identification of major event days using the 2.5 beta (β) method. The IEEE considered a methodology for excluding catastrophic events from the data used to calculate reliability measures.

We support the approach detailed in the AEMC's Report that the exclusion of catastrophic events from the data set used by distribution networks to calculate reliability measures should be based on the IEEE's 4.15 beta (β) method.

Churn in feeder categories

Two categorisation issues were raised in the course of the AEMC Review concerning disruptive changes in feeder classifications:

- Weather can cause feeders to shift between categories (usually between rural short and urban) from year to year and can adversely impact on STPIS outcomes; and
- Fringe urban expansion can result in a change that results in the reclassification of rural short feeders to urban, and a change to a higher reliability performance target.

Under the current STPIS and benchmarking arrangements, the actual loading is used to classify urban feeders, and hence short rural feeders based on load density (a load density greater than 0.3 MVA/km). This has meant that some feeders have been reclassified from short rural to urban following a particularly hot summer, or from urban to short rural following a mild summer. The AEMC's Report proposes to address the churn in feeder categories due to seasonal weather variations, by modifying the definition of an urban feeder. The change would replace actual maximum demand with weather normalised maximum demand. The practical effect of this change could provide greater certainty for some networks around investment decisions as performance is not subject to undue fluctuations due to feeder category churn. We support networks having the flexibility to apply feeder classifications on the basis of weather normalised maximum demand where there is likely to be a material benefit to customers.

15.4. Demand management incentive scheme (DMIS)

The DMIS as set out in clause 6.6.3(a) of the Rules, provides incentives for us to implement efficient non-network alternatives through demand-side or generation solutions. For the current regulatory control period, we were allocated $2 million over five years as an ex-ante allowance under the DMIA. We plan to spend this full allocation by the end of this current regulatory period on three projects:

- Doncaster Hill District Energy Services Scheme (DESS);
- Virtual Power Plant (VPP) Pilot (Stage 1); and
- Bulleen Demand Response (Summer Saver) Pilot.

Our Annual DMIS Reports to the AER during the course of the current regulatory period detail the successes and learnings obtained from each of these initiatives. The successes to date and the likely use of the full allocation of

DMIS funding in the current period have prompted us to propose an increase in DMIS funding allocation for the forthcoming regulatory period to enable us to further explore demand management opportunities and capabilities.

Our peak demand is highly temperature dependant, particularly to hot weather. Our 2013-14 load duration curve demonstrates that the top 750MW of the approximately 2,000MW peak is used for less than 5 per cent of the year (440 hours per annum). Furthermore, the top 500MW is used for less than 1.5 per cent of the year (130 hours per annum), all of which occur on hot summer days. Capacity is added economically to our network to meet peak demand using long-established probabilistic planning techniques. Despite our augmentations being economic, a significant amount of capacity on the network remains unutilised for the majority of the year because of the shape of the load-duration curve. This highly volatile demand profile warrants the investigation of lower cost non-network solutions as potentially better alternatives to network augmentation in the form of demand-side management or distributed embedded generation to meet these short-term peaks.

Our vision for managing peak demand into the future is to manage demand in real time with a finer level of control, enabling intelligent demand shaping capable of moving discretionary loads to off-peak times, to reduce capex on network augmentation and to minimise the risk of overload-related load shedding. To do this, we need to build on our demand management capabilities over time.

During the forthcoming regulatory period (and by 2020) we would like to be able to:

- Develop new demand management capabilities funded by the 2016-2020 DMIA to provide additional and enhanced levers for managing demand;
- Incorporate demand management options into our network planning business cases such that new demand management capabilities developed during the regulatory period are available for "business-as-usual", economically ranked against more traditional network augmentations;
- Have ICT systems established, funded by the 2016-2020 ICT regulatory allowance, to support the new or enhanced demand management capabilities; and
- Demonstrate that our demand management initiatives are capable of deferring network augmentation.

We are seeking DMIS funding for the following projects during the forthcoming regulatory period:

- District Energy Services Scheme (DESS) – a continuation of the current project to facilitate non-network solutions to defer augmentations planned for the Doncaster area;
- Smart Grid Activation – to trial controlled EV charging and smart appliance control;
- Summer Saver Trial – a pilot to test the feasibility of our directly controlling customer load blocks at high demand with the pilot focused on pool pump control and supply capacity limiting, and an expansion of the current pilot to increase participation volumes likely to be trialled in the Bulleen/Templestowe area and constrained areas of the network; and
- Monash University Dynamic Pricing Pilot – a project to implement dynamic pricing signals at Monash University campuses to manage the peak demands at each campus.

The total DMIA (Part A) required for the forthcoming regulatory period is $6.6 million over five years.

We have made a formal submission to the AEMC's consultation on the DMIS and support the proposed incentives for DNSPs to access the upstream benefits of demand management.

15.5. Victorian Government F-factor Scheme

As noted in the AER's Framework and Approach paper, the Victorian Government intends to review the F-factor scheme in 2015. We will participate in the Victorian Government's public consultation process about the scheme.

The AER has indicated that it intends applying this scheme in its amended form in the forthcoming regulatory period.

16. Pass through events

Key messages:

- Pass through events allow risks of unpredictable events to be managed in a way that minimises costs to our customers.
- We are proposing nominated pass through events for terrorism, natural disasters, insurance caps, insurer's credit risk, retailer insolvency and the introduction of the National Energy Customer Framework.

16.1. Introduction

As a DNSP, we are exposed to unpredictable, high cost events that are beyond our control. The Rules provide for a 'cost pass through' mechanism to enable the costs arising from such events to be recovered from customers. This approach ensures that costs are only recovered from customers if they arise from particular pre-defined events and are efficiently incurred.

The Rules recognise the following as pass through events:

- A regulatory change event;
- A service standard event;
- A tax change event; and
- A retailer insolvency event (although this is not effective in Victoria[103]).

In addition to those defined events, the Rules allow the AER's distribution determination to specify additional pass through events, which are known as 'nominated pass through events'. In accordance with these arrangements, we propose that the following additional nominated pass through events should apply in the forthcoming regulatory period:

- Terrorism event;
- Natural disaster event;
- Insurance cap event;
- Insurer's credit risk event;
- Retailer insolvency event; and
- National Energy Customer Framework event (NECF).

Of these nominated pass through events, the only provision not previously adopted by the AER is the NECF event. The remainder of this chapter addresses each of these nominated pass through provisions in turn. The chapter concludes by noting that the pass through provisions should apply to Standard Control Services and Alternative Control Services.

16.2. Terrorism event

The nature of a terrorism event makes it impossible to forecast either its occurrence or the cost impact. A pass through mechanism is therefore an appropriate regulatory mechanism to address the impact of a terrorism event. A pass through mechanism avoids the need to make a prior allowance for the cost of a terrorism event in our

[103] The 'retailer insolvency event' was introduced to the Rules as a pass through event (as a modification to the then existing definition of 'pass through event') in jurisdictions applying the National Electricity (National Energy Retail Law) Amendment Rule 2012. Those NECF amendment rules also introduced a definition of 'retailer insolvency event' as well as clauses 6.6.1(c)(6)(iii), 6.6.1(l) and 6.6.1(m). Those NECF amendment rules do not apply in Victoria. The National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012 No. 4 inserted clause 6.6.1(a1) to the Rules and made a consequential amendment to the definition of 'pass through event'. Clauses 6.6.1(a1) and the definition of 'pass through event' apply in Victoria, however, 6.6.1(c)(6)(iii), 6.6.1(l), 6.6.1(m) and the definition of 'retailer insolvency event' do not.

building block revenue requirement. We propose that the following definition should apply for the forthcoming regulatory period:

> A terrorism event is:
>
> 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, but not limited to, the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear).

16.3. Natural disaster event

The same rationale applies in proposing a natural disaster pass through event. We propose that the following definition should apply for the forthcoming regulatory period:

> A natural disaster event is:
>
> Any major fire, flood, earthquake or other natural disaster beyond the reasonable control of United Energy that 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 material as that term is defined in the Rules (that is 1 per cent of United Energy's annual revenue requirement for a regulatory year).

16.4. Insurance cap event

The insurance cap event allows us to manage risk in circumstances where insurance premiums are prohibitively expensive. A pass through event benefits consumers because they are not required to fund excessive insurance premiums. Consumers would only bear the risk should an insurance cap event occur. We propose that the following definition should apply for the forthcoming regulatory period:

> An insurance cap event occurs if:
>
> (i) United Energy makes a claim or claims and receives the benefit of a payment or payments under a relevant insurance policy;
>
> (ii) United Energy incurs costs beyond the relevant policy limit.
>
> For this insurance cap event:
>
> The relevant policy limit is the greater of:
>
> (i) United Energy's actual policy limit at the time of the event that gives, or would have given rise to a claim; and
>
> (ii) 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.
>
> A relevant insurance policy is an insurance policy held during the 2016-20 regulatory control period or a previous regulatory control period in which United Energy was regulated.

16.5. Assessment of terrorism event, natural disaster event and insurance cap event.

Each of the definitions of terrorism event, natural disaster event and insurance cap event accord with the nominated pass through event considerations specified in the Rules because:

- The event proposed is not already in the Rules;
- The event is clearly identified;

- A prudent service provider could not reasonably prevent the event from occurring or substantially mitigate the cost impact of such an event as each is effectively uncontrollable;
- We cannot insure against the event on reasonable economic terms;
- We cannot self-insure the event on the basis that it is not possible to calculate the self-insurance premium and the potential cost would have a significant impact on our ability to provide distribution services;
- The event is consistent with nominated pass through events accepted in the AER's recent NSW draft determinations.

We propose the following minor drafting changes to the AER's definition in the NSW draft determinations:

- The references to 'materially increasing costs' in the definition of the events have been removed as the requirement for materiality is dealt with in the definition of a positive pass through event; and
- We have removed the AER's assessment factors that it will have regard to when assessing a claim for a pass through. These factors address the AER's assessment of a pass through claim, a process already governed by the provisions of the Rules. Our proposal relates to the definition of the nominated pass through event, which is distinct from the assessment process. Including assessment factors is also inconsistent with the four pre-defined pass through events under the Rules.

16.6. Insurer credit risk event

We operate our business with a prudent level of insurance with our nominated insurers. However, if an insurer were to become insolvent, whilst a low probability, there could be a potential and significant cost impact on us. This risk is uncontrollable and we are not in a position to take prudent and efficient actions to mitigate such a risk. It is thus appropriate to treat it as a cost pass through.

We propose that the following definition should apply for the forthcoming regulatory period:

> An insurer's credit risk event is:
>
> Insurer Credit Risk Event means an event where the insolvency of the nominated insurers of United Energy occurs, as a result of which United Energy:
>
> (i) Incurs higher or lower costs for insurance premiums than those incurred immediately prior to the insolvency; or
>
> (ii) In respect of a claim for a risk that would have been insured by the United Energy's insolvent insurers, is under a new policy subject to a higher or lower claim limit or a higher or lower deductible than would have applied under the policy with the insolvent insurer; or
>
> (iii) Incurs additional costs associated with self-funding an insurance claim which would have otherwise been covered by the insolvent insurer.

This definition accords with the requirements of the nominated pass through event considerations because:

- The event proposed is not already in the Rules
- The event is clearly identified
- A prudent service provider could not reasonably prevent the event from occurring or substantially mitigate the cost impact of such an event as it depends on the business decisions and action of the insurer. We manage our risk of insurer insolvency at the time of placing insurance by selecting insurers with a S&P credit rating of Standard and Poor's A- or better. In addition, our public liability and property (ISR) insurance policies include multiple insurers which allow us to diversify our insurer insolvency risk for these policies. While we monitor the credit ratings of our insurers to assess any deterioration in insurer credit risk, the possibility of an insurer becoming insolvent following placement is ultimately uncontrollable;
- As part of this annual process the ongoing viability and credit rating of the insurance company is assessed. We have no incentive to obtain insurance from providers who are not capable of paying large claims because this has the potential to leave us exposed. We can assess the viability of an insurer by reviewing its track record,

size, credit rating and reputation but, despite these efforts, the possibility of an insurer becoming insolvent is ultimately uncontrollable;

- We cannot insure against the event on reasonable economic terms;
- We cannot self-insure the event on the basis that it is not possible to calculate the self-insurance premium and the potential cost would have a significant impact on our ability to provide network services; and
- The event is consistent with nominated pass through events for the Victorian gas distribution businesses in the last AER determination.

16.7. Retailer insolvency event

We believe that even though clause 6.6.1(a1) of the Rules includes a retailer insolvency event, in Victoria that inclusion fails for want of a supporting definition and the scheme of clause 6.6.1 fails for want of certain supporting provisions[104].

We propose that the following nominated pass through event should apply for the forthcoming regulatory period:

> A retailer insolvency event occurs if:
>
> A retailer (as defined in the Rules) fails to pay United Energy an amount to which United Energy is entitled for the provision of direct control services (as defined in the Rules) where:
>
> (i) An insolvency official has been appointed in respect of that retailer; and
>
> (ii) United Energy is not entitled to payment of that amount in full under the terms of any credit support provided in respect of that retailer.
>
> For this retailer insolvency event, the Rules shall be read and applied as if:
>
> (i) Clauses 6.6.1(c)(6)(iii), 6.6.1(l) and 6.6.1(m) applied in Victoria,
>
> (ii) In clause 6.6.1(l), "*retailer* insolvency costs" were omitted and substituted with "*retailer insolvency costs*",
>
> (iii) The definition of 'positive change event' were amended, and the definition of 'retailer insolvency costs' inserted, as proposed by the COAG Energy Council on 20 March 2014 giving rise to the AEMC Consultation paper for a National Electricity Amendment (Retailer insolvency events – cost pass through provisions) Rule 2015, and
>
> (iv) 'retailer insolvency costs' is a defined term in the Rules, defined as proposed by the COAG Energy Council on 20 March 2014 giving rise to the AEMC Consultation paper for a National Electricity Amendment (Retailer insolvency events – cost pass through provisions) Rule 2015.

The definition accords with the requirements of the nominated pass through event considerations because:

- The event proposed is not already in the Rules in a legally effective manner;
- The event is clearly identified;
- A prudent service provider could not reasonably prevent the event from occurring or substantially mitigate the cost impact of such an event as it cannot refuse to do business with a retailer even if considered not credit worthy;
- We cannot insure against the event on reasonable economic terms;
- We cannot self-insure the event on the basis that it is not possible to calculate the self-insurance premium because the probability of the event occurring cannot be readily estimated and the potential cost would have a significant impact on our ability to provide network services;
- A retailer insolvency event is included within the Rules and is effective in all jurisdictions other than Victoria. We therefore rely on consistency with other participating jurisdictions that have started the NECF as a relevant

[104] See section 17.1 above and the footnote noted there.

matter to be considered by the AER. We also rely on the submission of the COAG Energy Council referred to in the event definition dated March 2014.

16.8. National Energy Customer Framework

The timing of the adoption of all or parts of NECF in Victoria is currently unknown.

The previous Victorian Government issued a Victorian energy statement in October 2014. Priority 1.3 states that:

> "The Victorian government's retail energy regulatory arrangements will transition to NECF by 31 December 2015. A review of the NECF in Victoria will be undertaken in 2018 to ensure that it is benefitting Victorian consumers."

This position of the previous Victorian Government appears unlikely to be supported by the current Government based on Australian Labor Party material published before the recent election, which stated that:

> "Labor does not currently support the move to the National Energy Customer Framework (NECF) because it would not offer the same sort of existing consumer protections – in fact it would lower protections. Recent developments in the energy retail market particular to Victoria have raised some serious challenges which an Andrews Labor government would tackle. Labor commits to working with NECF to ensure that necessary consumer protections become a feature of the national framework, and supports harmonisation wherever possible."[105]

Whilst the Labor position implies no adoption of NECF in the near term, it does contemplate that NECF will commence at some point, as Labor supports eventual harmonisation.

Our forecast capex and opex step changes do not include any future NECF requirements as the supporting Victorian instruments and the finalised initial smart metering customer protections are not available. Given that the NECF commencement date and full set of regulatory obligations are unclear, we seek a cost pass through that operates in a similar manner to that recently provided to the gas network businesses in Victoria.

We propose that the following definition should apply for the forthcoming regulatory period:

> National Energy Customer Framework Event means a legislative or administrative act or decision that:
>
> (i) Occurs during the regulatory control period;
>
> (ii) Has the effect of implementing in Victoria, either in part or in its entirety, the National Energy Customer Framework; and
>
> (iii) Increases the costs to United Energy of providing direct control services.
>
> For the purposes of this definition:
>
> The "National Energy Customer Framework" means any regulatory instruments (including, but not only, legislation, codes, guidelines, regulations or rules) that give effect, in Victoria, to any or all of the Schedule to the National Energy Retail Law (South Australia) Act 2011, the National Energy Retail Regulations (South Australia) and the National Energy Retail Rules (South Australia) as amended from time to time including any amendment, withdrawal or introduction of any associated Victorian regulatory instruments (including, but not only, legislation, codes, guidelines, regulations or rules).
>
> The increase in costs will, for the purposes of the definition of *materially* in Chapter 10 of the Rules, be deemed to meet that definition, but only for the purposes of that definition. The *eligible pass through amount* will be the actual increase in costs.

[105] ALP 2014 Campaign Material – ESC Powers, page 6

This definition accords with the requirements of the nominated pass through event considerations because:

- The event proposed is not already in the Rules;
- The event is clearly identified with reference to the commencement of NECF in Victoria;
- A prudent service provider could not reasonably prevent the event from occurring or substantially mitigate the cost impact of such an event as the Victorian Government is solely in control and the event will only be triggered following a legislative act or decision of the Victorian Government;
- We cannot insure against the event but it might also have a significant cost impact;
- We cannot self-insure the event on the basis that it is not possible to calculate the self-insurance premium and the potential cost would have a significant impact on our ability to provide network services; and
- The event is consistent with nominated pass through events for the Victorian gas distribution businesses in the last AER determination. In particular, no materiality threshold should apply for this defined pass through event. There is ongoing uncertainty as to the timeframe for the implementation of the NECF and the extent to which the state regulatory regime may be amended to reflect NECF in the interim. Given this added uncertainty—and noting that this event is entirely beyond our control—it is appropriate to allow us to pass through costs associated with the commencement of NECF in Victoria, without a materiality threshold.

16.9. Application of pass through provisions to Alternative Control Services

We propose that the pass through provisions for defined and nominated pass through events apply to Alternative Control Services on the basis that the pass through provisions in the Rules apply to direct control services, which includes both standard control services and Alternative Control Services.[106]

We note the application of this approach is consistent with the AER's decision in the NSW DNSPs 2009-14 distribution determination, ActewAGL's 2009-14 distribution determination, Queensland DNSPs 2010-2015 distribution determination and SA Power Networks (formerly ETSA Utilities).

We support the AER's view that it is appropriate to apply the pass through provisions of the Rules to Alternative Control Services, as all direct control services are subject to the distribution determination.[107] We also support the AER's view that the Rules do not preclude the pass through provisions from applying to Alternative Control Services for defined events and nominated events accepted by the AER.[108]

Further, whilst the classification of services is essential in determining the extent of regulation, it is not a determining factor in deciding whether or not the pass through, as a mechanism to compensate for risks or allocating of the consequences of risk, should be made available. Rather, it is the fact that we, as a provider of distribution services, face risks, the cost impact of which (if the risk materialises) is most appropriately borne by customers. The risk we face in providing that service does not change or dissipate simply because the classification has changed. We are still facing the same risk, which if materialised would have an impact on the cost of providing that service(s).

Consequently, as a provider of distribution services, we face risks that would impact on the cost of providing these distribution services. The cost consequence of some of these risks should (in accordance with the Rules with respect to defined pass through events or AER approved pass through events) be borne by customers if the risk materialises and has a material impact on our costs in providing direct control services. Under such circumstances, we should be able to recover these costs irrespective of how the services, which were impacted by the events/risk materialising, were classified by the AER for the purpose of determining the extent of regulation. This is consistent with section 7(A)(2)(a) and (b) of the NEL, which provides that we should be given a reasonable opportunity to be able to recover at least the efficient costs the operator incurs in providing direct control services and complying with regulatory obligations or requirements.

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[106] Refer to Chapter 10 of the Rules – definitions of 'negative change event', 'positive change event', 'regulatory change event', 'tax change event', 'service standard event', and 'retailer insolvency event.' See also Essential Energy proposed definition for its proposed nominated pass through events.

[107] AER, *Draft Decision – South Australia: Draft distribution determination 2010-11 to 2014-15,* 25 November 2009, p 407. See also AER, *Draft Decision – Queensland: draft distribution determination 2010-11 to 2014-15,* 25 November 2009, p 347.

[108] AER, *Draft Decision – New South Wales: draft distribution determination 2009-10 to 2013-14,* 21 November 2008, p 286

17. Annual revenue requirements, X-factors

Key messages:

- Our total revenue requirement has been calculated in accordance with the building block approach set out in the Rules.
- We are proposing a reduction in our revenue to account for the use of shared assets in earning non-regulated revenue from National Broadband Network Company (NBNCo), Telstra and Optus.
- We propose an X factor for our standard control services in 2016 of 7.19 per cent and an X factor of zero per cent per annum for the period 2017 to 2020.

17.1. Regulatory requirements and chapter structure

This Chapter summarises our building block proposal and X factor for the forthcoming regulatory period.

The indicative prices and bill impacts for our customers that will result from the proposed revenue requirements are explained in chapter 19. The remainder of this chapter is structured as follows:

- Section 17.2 summarises the building block components for each year of the forthcoming regulatory period;
- Section 17.3 sets out the revenue reduction in relation to shared assets; and
- Section 17.4 presents our proposed X factor.

17.2. Annual building block revenue requirements

Table 17-1 below summarises the composition of the unsmoothed building block revenue requirements for the forthcoming regulatory period.

Table 17-1: Total revenue requirement ($M, Nominal)

	2016	2017	2018	2019	2020	Total
Return on Capital	101.0	109.5	118.0	126.4	134.3	**589.1**
Depreciation	121.4	136.9	148.7	137.2	145.8	**690.0**
Opex (incl. Debt Raising)	161.7	167.1	172.2	179.5	182.3	**862.8**
Efficiency Benefit Sharing Scheme	3.3	20.2	5.4	0.2	0.0	**29.2**
Shared Assets	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	**(2.9)**
Cost of corporate income tax	31.9	32.8	31.9	24.9	27.6	**149.1**
Total Revenue Requirement (unsmoothed)	**418.7**	**465.8**	**475.7**	**467.6**	**489.4**	**2,317.2**

Each of the elements in Table 17-1 has been addressed in earlier chapters of this Regulatory Proposal. It should be noted that the total revenue requirement set out above is subject to a shared asset adjustment, as explained in the next section.

The total revenue requirements shown in Table 17-1 have been calculated in accordance with the post-tax revenue model, as required by clause 6.3.1(c)(1) of the Rules.

17.3. Shared assets and proposed adjustment

DNSPs are sometimes able to make use of regulated assets to provide services that are not regulated by the AER. These assets are called 'shared assets' because they are shared between a regulated and unregulated activity. An example is a power pole, which provides distribution services, but also supports a fibre optic cable for communications services. In this example, the power pole is a shared asset.

The regulatory treatment of shared assets has been the subject of a recent AEMC review and a Rule change. The new Rules allow the AER to reduce a DNSP's annual revenue requirement to reflect the costs attributable to services generating unregulated revenues. In accordance with the Rules, the AER has published guidelines that provide further details on how these arrangements should apply.

The AER's guidelines set a materiality threshold for unregulated revenues from shared assets, below which no cost reduction applies. In particular, the guidelines state that the use of shared asset is material when a DNSP's annual unregulated revenue from shared assets is expected to be greater than 1 per cent of its total smoothed revenue requirement for a particular regulatory year.

In the forthcoming regulatory period, we expect to earn unregulated revenue from shared assets in relation to telecommunication services provided to NBNCo, Telstra and Optus. Table 17-2 shows that our expected annual unregulated revenue from these activities exceeds the AER's materiality threshold.

Table 17-2: Materiality shared asset use ($M, Nominal)

	2016	2017	2018	2019	2020	Total
Forecast unregulated revenue from shared assets	6.3	5.5	5.5	5.5	5.5	28.1
Unadjusted revenue requirement	0.5	0.5	0.5	0.5	0.5	2.7
Materiality percentage (per cent)	9	10	10	10	10	10

The AER's shared assets guidelines provide for a reduction of 10 per cent of the value of the service provider's expected total unregulated revenues from shared assets in each year of the forthcoming regulatory period[109]. Given this requirement and our estimated unregulated revenues from shared assets, our total revenue requirement is adjusted as shown in Table 17-3.

Table 17-3: Adjusted Revenue Requirement ($M, Nominal)

	2016	2017	2018	2019	2020	Total
Unadjusted regulated revenue requirement	419.2	466.4	476.2	468.1	490.0	**2,320.0**
10 per cent of shared asset revenue	0.5	0.5	0.5	0.5	0.5	**2.7**
Adjusted regulated revenue requirement	**418.7**	**465.8**	**475.7**	**467.6**	**489.4**	**2,317.2**

In accordance with the Rules' requirements, we therefore propose to recover the adjusted smoothed regulated revenue through our network charges for standard control services.

[109] AER, Shared Asset Guideline, November 2013, clause 3.1(d).

17.4. X Factor

An X factor of 7.19 per cent is proposed as this ensures that the our allowed revenues and building blocks costs will be closely aligned in 2020 and provides a relatively stable price path over the forthcoming regulatory period. This approach is consistent with the provisions set out in clauses 6.5.9(b) and (c), and 11.60.3(b)(1) of the Rules.

Consistent with our position discussed in section 10.11.2, it is important that the X factor in 2020 (being the final year of the Distribution Determination) is zero. This will address the issue of the issue of artificially reducing our capital contributions under Guideline 14 and avoid the wealth transfer from our existing customers to developers (and other new customers).

In our Revised Regulatory Proposal, we may propose different X factors in the early years of the forthcoming regulatory period to meet our cash flow requirements and our transition to capacity tariffs. We will extensively consult with stakeholders on this during the development of our Tariff Structure Statement.

18. Metering services

Key messages:

- A national framework is currently being developed to introduce competition in the provision of metering services for domestic and commercial customers.
- We support the AER's proposed service classification and form of regulation. In particular, we agree that:
  - Competitively provided metering services should not be regulated; and
  - Metering services provided prior to the introduction of competition will be classified as an alternative control service and regulated in accordance with a revenue cap.
- We have proposed clarifications to the AER's proposed revenue cap formula to ensure that revenue received from exit fees and new connections is treated appropriately. Our proposed approach is consistent with standard regulatory practice.
- We have estimated the cost of implementing the new national framework. The majority of these costs arise in the core distribution business rather than the metering activity, and have been allocated accordingly.
- The cost of introducing competition is uncertain because the design of the national framework has not been settled. Given this uncertainty, a case could be made for a pass through mechanism to manage the risk of forecasting error. If the AER preferred this approach, we would accept it.
- We propose an exit fee for remotely read interval meters in accordance with the CROIC and clause 11.17.6 of the Rules. We have provided a submission on our exit fee alongside this Regulatory Proposal. In the limited circumstances where we are required to restore metering services on a regulated basis (as a 'metering provider of last resort', for example) we will charge the AER-approved service vehicle fee.

18.1. Service classification and form of regulation

The future arrangements for the provision of metering and related services are the subject of national reform. The objective of this reform is to establish a competitive market for the supply, installation and operation of advanced metering with communications capability (AMI or 'smart meters').

The AER's proposed approach – which we support – is that regulation should not apply where metering services are provided on a competitive basis.

In Victoria, the Government decided that DNSPs should be solely responsible for the rollout of smart meters to residential and small business customers. The AEMC has recently published draft Rule changes that would introduce metering competition from 1 July 2017. For further background information on the national program for introducing competition in metering, please refer to the supporting document 'Revenue Capped Metering Services'.

The charges for smart meters are currently regulated by the AER under the CROIC. These arrangements continue until 31 December 2015, after which date these services are subject to economic regulation under the Rules.

Importantly, however, a number of other provisions in the CROIC continue to apply beyond 31 December 2015, and therefore must be reflected in the AER's approach to setting metering charges[110].

In light of this background, the AER's Framework and Approach paper considered how metering services should be classified and regulated in the forthcoming regulatory period.

[110] See, for example, clause 11.17.6 of the Rules and clauses 3.2(b) and 3.2(c) of the CROIC.

Table 18-1 summarises the AER's proposed classification and form of regulation for different metering types.

Table 18-1: AER's proposed approach to classifying and regulating metering service

Service	Proposed classification	Proposed form of regulation
Metering type 1 to 4 (excluding smart meters)	Unclassified	Not applicable
Type 5 and 6 and smart metering services - regulated service (i.e. metering provision not subject to competition)	Alternative control	Revenue Cap
Type 5 and 6 and smart metering services - unregulated service (i.e. metering provision subject to competition)	Unclassified	Not applicable
Metering type 7	Alternative control	Revenue Cap
Auxiliary metering services	Alternative control	Revenue Cap

Source: AER

Table 18-2: Metering installation types

Metering type	Description
Type 1 to 4 meters [111]	These are generally used by large customers who consume greater than 160 megawatt hours (MWh) of electricity per annum. However, a residential or small business customer consuming 160MWhpa or below could select a retailer offering which included a type 4 remotely read interval meter. Types 1 to 4 have the capability to record the time of use of energy and are read remotely.
Type 5 meters	Manually read interval meters with capability to record time of use of energy. These meters are provided by the DNSP for a residential or small business customer consuming 160MWhpa or below.
Type 6 meters	Manually read accumulation meters which simply record total electricity usage. Formerly the default meter type in Victoria for residential or small business customer consuming 160MWhpa or below.
Type 7 meters	Type 7 meters are unmetered connections - streetlights. Usage of electricity by type 7 meter connections is calculated using inventory and load tables consistent with the requirements of the National Metrology Procedure.

Source: AER

Table 18-1 shows that three types of metering services are to be classified as Alternative Control Services:

- Type 5 and 6 and smart metering services (not subject to competition);
- Metering type 7; and
- Auxiliary metering services.

The exit and restoration fees that are discussed in this chapter are classified as Alternative Control Services and are therefore included in Chapter 21.

The AER has concluded that the first of these metering services should be subject to a revenue cap. The remaining services are fee-based services. All fee-based and quoted Alternative Control Services are discussed in Chapter 21

[111] In Victoria, when a type 4 meter is used as a replacement for a type 5 or type 6 meter it is deemed to be a type 5-6 meter under a derogation set out in clause 9.9C of the NER. The AER defines type 4 meters installed under clause 9.9C as 'smart meters'. This is necessary as different regulation requirements exist for type 4 meters installed for general use, as against type 4 meters installed under clause 9.9C.

of this Regulatory Proposal, while public lighting is addressed in Chapter 22. The focus of this Chapter is the revenue capping arrangements for Type 5 and 6 and smart metering services (not subject to competition).

18.2. Revenue cap design

The AER's proposed revenue formula for Type 5 and 6 and smart metering services (not subject to competition) is reproduced below[112]:

(1) $$MAR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_t^{ij} q_t^{ij}$$ i=1,...,n and j=1,...,m and t=1,...,5

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

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

Where:

MAR_t

is the maximum allowable revenue in year t.

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

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

AR_t is the annual revenue requirement for year t.

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

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

B_t is the sum of annual adjustment factors in year t for the overs and unders account.

CPI_t is the percentage increase in the CPI. This parameter will be decided in the final decision.

X_t is the X-factor in real terms in year t, incorporating annual adjustments to the post-tax revenue model for the trailing cost of debt where necessary. This parameter will be decided in the final decision.

We support the above formula, subject to the following qualifications:

- The revenue cap formula includes an adjustment T_t, which we assume will give effect to the transition charges provisions in clause 5L of the CROIC. We note that these provisions ensure that all relevant costs, including those associated with the Regulated Asset Base and opex, are captured as we transition from the regulatory arrangements under the CROIC to the AER's determination. To avoid any doubt, the revenue cap formula should specifically refer to the relevant CROIC provisions;
- The calculation of revenue should exclude any exit fees (discussed in section 18.3) received. Exit fees are not revenue for the provision of metering services. Instead, an exit fee is a payment for retiring an existing remotely

112 AER, Final Framework and Approach for the Victorian Electricity Distributors Regulatory control period, commencing 1 January 2016, 24 October 2014, page 61.

read interval meter (but not a Type 5 or Type 6 meter). The exit fee enables the distributor to recover the remaining capital value of the interval meter, the commissioned telecommunications and information technology systems and also recover the additional operating expenditure in retiring the meter. The revenue from exit fees should be treated as follows:

 - The capital component of any exit fees received during the forthcoming regulatory period should be deducted from the Regulated Asset Base at the commencement of the subsequent regulatory period (being 1 January 2021). This approach is analogous to the regulatory treatment of asset disposals; and
 - The opex component defrays the incremental costs of retiring meters, and therefore should also be excluded from the revenue cap.

- As explained in the supporting document, Revenue Capped Metering Services, competition is assumed to commence on 1 July 2017. Consequently, the number of meters provided for new connections prior to the commencement of competition (and remunerated through the revenue cap) is also uncertain. To address this volume risk, we propose that meter purchase costs and revenues for new connections are excluded from the revenue cap. This approach is analogous to the standard regulatory approach to new connections for standard control services; and
- We also propose that an adjustment is made to address differences between the forecast and actual number of existing meters that will be subject to competition (or churn) in the future . This adjustment can be included in the AER's true-up term B_t, and details of the proposed formula are provided in the supporting document, Revenue Capped Metering Services.

In this Regulatory Proposal, we have included our best estimate of the forecast costs of implementing the reform related to expanding metering competition.

We would welcome further dialogue with the AER on the final form of the revenue cap formula in order to address the issues noted above. In our view, our proposed treatment of exit fees and new connections is consistent with standard regulatory practice, and would deliver a better outcome for our customers and the industry.

18.3. Exit fees and restoration fees

The CROIC and clause 11.17.6 of the Rules allow a distributor to apply to the AER for approval of an exit fee in relation to a remotely read interval meter. In broad terms, this exit fee provision enables a distributor to recover the written down capital value and the operating costs of retiring a meter if a customer elects to obtain metering services from an alternative provider. The exit fee is a logical consequence of the mandated rollout program, which required distributors to incur costs in providing smart meters to all residential and small business customers. Without the safety net of an exit fee, distributors would not have delivered the rollout program, which is already delivering significant benefits to customers.

Clause 7.2 of the CROIC sets out the principles that should apply in the calculation of an exit fee. In addition, clauses 11.17.6(b) and (c) of the Rules state:

> (b) [..] for a relevant regulatory control period services to which exit fees under clause 7, or restoration fees under clause 8, of the AMI Order in Council applied are to be classified as Alternative Control Services and are to be regulated by the AER on the same basis as applied under the AMI Order in Council.
>
> (c) For paragraph (b), a relevant regulatory control period is a regulatory control period commencing on or after 1 January 2016 and before 1 January 2021.

The above provisions therefore require the AER to regulate exit fees in accordance with the CROIC for the duration of the forthcoming regulatory period.

Our application for an exit fee is provided as an attachment to this Regulatory Proposal and is submitted in accordance with clause 7.1A of the CROIC and clause 11.17.6 of the Rules.

The restoration fee referred to in clause 11.17.6(b) of the Rules arises where a retailer ceases to be the responsible person in respect of a metering installation for a customer, and the DNSP becomes the responsible person in respect of that metering installation. In the limited circumstances where we are required to restore metering services on a regulated basis (as a 'metering provider of last resort', for example) we will charge the AER-approved service vehicle fee.

18.4. Building block for regulated metering services

The AER's Framework and Approach paper explains that a building block approach will be adopted to determine the revenue requirement for regulated metering services.

In forecasting the building block components, we have adopted the following assumptions:

- Metering competition will start on 1 July 2017, and new meters will be provided on a competitive basis
- Any remaining type 5 or 6 meters will be progressively replaced on a contestable basis;
- We will replace faulty meters on a regulated basis even when competition commences;
- An estimated 1 per cent of existing meters will be replaced on retailer churn; and
- Approximately 2,500 meters per annum will be replaced due to additions or alterations.

On the basis of the above assumptions, we estimate that approximately 10 per cent of our customers will have meters provided on a competitive basis by the end of 2020.

In addition to the above assumptions, we must also allocate capex and opex between our distribution network and metering activities, as each activity is subject to its own revenue cap. This is particularly important because the scope of services provided in accordance with the CROIC was substantially broader than the scope of services covered by the AER's revenue cap for metering services. It is important to recognise this difference in the building block calculations for the forthcoming regulatory period.

To facilitate the introduction of competition, each DNSP will need to have systems and processes in place to facilitate the efficient churning of metering service providers, while still ensuring accurate billing. Our systems will need to accept metering data and meter register data for every meter type from any accredited party. In addition, we will need to follow up missing data with meter data requests and receive transactions from a range of new parties.

Our cost allocation approach is summarised below:

- Dedicated metering systems are allocated to the metering activity. For example, the costs of the meter reading system (Itron MVRS); and
- Where systems are required to meet our distribution business obligations these are largely allocated to the distribution business with an allocation to the metering services on an incremental basis. For example, the system for management of interval meter data (Itron IEE) is considered to be a distribution system and ongoing projects are allocated to the metering Alternative Control Services on an incremental basis.

The assumptions and cost allocation arrangements set out above are reflected in the regulated metering asset base and building block calculations show in the tables below.

Table 18-3: Metering regulatory asset base for 2016 – 2020 ($M, Real 2015)

	2016	2017	2018	2019	2020
Opening Regulatory Asset Base	205.7	184.0	156.5	138.0	122.2
Inflation on Opening Regulatory Asset Base	0.0	0.0	0.0	0.0	0.0
Plus Capex (Excl. Funding)	10.5	6.1	1.1	1.5	3.5
Plus Funding Costs	0.2	0.1	0.0	0.0	0.1
Less customer contributions	0.0	0.0	0.0	0.0	0.0
Less regulatory depreciation	(32.5)	(33.8)	(19.6)	(17.3)	(16.8)
Less disposals	0	0	0	0	0
Closing Regulatory Asset Base	**184.0**	**156.5**	**138.0**	**122.2**	**109.0**

Table 18-4: Building block calculation for regulated metering services ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Return on Capital	14.8	13.2	11.3	9.9	8.8	**58.1**
Return of Capital	27.5	29.3	15.8	13.9	13.8	**100.3**
Operating Expenditure	5.4	5.4	5.4	5.4	5.3	**26.9**
Revenue Adjustments	2.5	0.0	0.0	0.0	0.0	**2.5**
Net Tax Allowance	0.0	0.0	0.0	0.0	0.0	**0.0**
Annual Revenue Requirements	**50.2**	**47.9**	**32.5**	**29.2**	**28.0**	**187.7**

Further information on the building block calculation is provided in the supporting document, Revenue Capped Metering Services.

18.5. X Factor

An X factor of 64.6 per cent is proposed for 2016 and X factors of zero for the remainder of the period.

In our Revised Regulatory Proposal, we may propose different X factors in the early years of the forthcoming regulatory period to meet our cash flow requirements.

19. Indicative prices and bill impacts

Key messages:

- We will deliver a price cut of approximately $70 for a typical customer in 2016 for our Standard Control Service and Revenue Capped Metering Services.
- We will keep real prices at this reduced level for the remainder of the forthcoming five year period.

This chapter details the indicative prices that are forecast to recover revenues equal to, in net present value terms, the unsmoothed annual revenue requirements for Standard Control Services and revenue capped metering services, as detailed in Chapters 17 and 18.

We have derived our indicative prices complies in accordance with the requirements of Chapter 6 of the Rules.

Table 19-1 shows our indicative price changes across our Standard Control Services and revenue capped metering services.

Table 19-1: Average price outcomes — Standard Control Service and Revenue Capped Metering combined

Tariff type	2015 $	2016 $	2016 %
Small (LVS1R)	449.04	371.61	(17.24)
Medium (LVM1R)	8,806	9,444	7.25
Large (HVkVATOU)	271,939	291,627	7.24

In accordance with Chapter 11 of the Rules, we will submit a Tariff Structure Statement to the AER by 25 September 2015 together with an Indicative Pricing Schedule, which will set out indicative prices for each year from 2017 to 2020. We are currently in the process of developing and consulting on our future tariff structures.

We expect that our Tariff Structure Statement will provide new and innovative tariff structures that will:

- Improve our price signals to customers to encourage more efficient investment and consumption decisions;
- Reduce the cross subsidies between different users of the network; and
- Allow customers to take better control of their electricity costs by making changes to their peak demand and energy consumption.

As part of our commitment to moving towards more cost reflective network tariffs and minimising the long term costs associated with building and maintaining our network, we introduced an optional demand tariff as part of our 2015 Annual Pricing Submission. This tariff structure has formed the basis of the analysis of the impact of demand tariffs on our maximum demand, as discussed in Chapter 9. We expect that our tariff structures for residential customers in our Tariff Structure Statement will include:

- A demand tariff with a structure consistent with our optional demand tariff including:
  - Maximum energy consumed by the customer in the highest a half an hour period between 3pm and 9pm on each month (c/KW);
  - An anytime any charge (c/kWh);
  - A pass throughs such as Premium and Transition Solar Feed in Tariffs (c/day); and
  - Standard AMI metering charge (c/day).
- Additional optional tariffs for customers who select specific services:
  - Locational incentives including location based peak time rebates;

- Alternative metering services;
- Connection and exit charges;
- Load control and demand management services; and
- Other new services.

Our Tariff Structure Statement will also set out mechanisms for transitioning existing customers from the legacy consumption tariffs to the new demand based tariff.

20. Framework and Approach

Key messages:

- We accept the AER's service classification.
- We accept the AER's control mechanisms.
- We accept the application of the AER's incentive schemes, subject to proposed changes to the STPIS.

The AER issued its Final Framework and Approach paper on in October 2014. This outlined its decisions to apply in the forthcoming regulatory period on:

- The classification of distribution service;
- The form of control mechanism;
- The application of incentive schemes;
- The application of the AER's expenditure forecast assessment guideline;
- Depreciation; and
- The treatment of various jurisdictional and legacy issues.

20.1. Classification of services

The AER grouped our distribution services into the following categories:

- Network services;
- Connection services;
- Metering services;
- Ancillary network services; and
- Public lighting.

We accept the AER's proposed service classification and its modifications between the current and forthcoming periods. These modifications are set out in Table 20-1 below. There will be a key change to the regulatory treatment of metering services in the forthcoming period. As explained in Chapter 18, Type 5, 6 and smart meters that we install before the end introduction of metering competition will be regulated as Alternative Control Services. New meters that we install after metering competition commences will be unregulated.

Table 20-1: Proposed changes to services classification

Service	Current classification	Proposed classification
Network services	Standard control	No change
Connection services		
Customer initiated undergrounding and / or rearrangement of distribution assets servicing that customer	Alternative control	standard control
Supply enhancement at customer request	Alternative Control	Unclassified
Supply abolishment (up to 100 amps)	Alternative Control (quoted)	Standard control
Metering services		
Installation, operation, repair & maintenance, and replacement of type 5, 6 and smart metering installations – not subject to competition	Unclassified*	Alternative Control
Installation, operation, repair & maintenance, and replacement of type 5, 6 and smart metering installations – subject to competition	Unclassified*	Unclassified
Collection of meter data, processing and storage of meter data and provision of access to meter data for type 5 and 6 metering installations	Unclassified*	Alternative Control
Meter exit services	Unclassified*	Alternative Control
Meter restoration service	Unclassified*	Alternative Control
Ancillary network services		
Reserve feeder construction	Alternative control (fee based)	Negotiated Service
Reserve feeder maintenance	Alternative control (fee based)	Alternative control (quoted)
Emergency recoverable works	Alternative control (quoted)	Unclassified
Public lighting		
Operation, maintenance and repair – dedicated public lighting assets	Alternative control (fee based)	Negotiated Service
Replacement – dedicated public lighting assets	Alternative control (fee based)	Negotiated Service

** Subject to regulation under AMI CROIC*

We have revised our Cost Allocation Method (Version 2) in light of the above changes to the service classification. This version was approved by the AER on 19 December 2014.

20.2. Control mechanism

In principle, we accept the AER's control mechanisms set out in the Final Framework and Approach paper, being:

- Revenue cap – for services we classify as Standard Control Services;
- Revenue cap – for regulated metering (not subject to competition) services classified as Alternative Control Services; and
- Caps on the prices of individual services – for services classified as Alternative Control Services.

We have prepared a separate attachment on control mechanisms which explains how we propose to adjust our prices for each year of the forthcoming regulatory period, and which sets out how we will comply with the requirements of the Rules that relate to setting prices. In particular the attachment discusses:

- Compliance with the relevant control mechanisms clause 6.12.1(13);

- Reporting and compliance with designated pricing proposal charges clause 6.12.1(19); and
- Reporting and compliance with jurisdictional scheme amounts clause 6.12.1(20).

The attachment also provides comments and analysis on the operation of the “unders” and “overs” mechanism under a revenue cap. The attachment therefore addresses certain elements of the over-arching revenue cap formulae. A relevant consideration is that, for the services mentioned below, the form of price control requires a true-up of the actual revenue as it varies to forecast:

- Standard control services;
- Type 5 and 6 regulated metering services;
- Designated pricing proposal charges; and
- Jurisdictional scheme amounts.

20.3. Application of incentive schemes

We accept the application of the following incentive schemes in the next period:

- EBSS;
- STPIS;
- DMIS; and
- CESS.

We propose that these schemes be applied in the manner set out in Chapter 15.

20.4. Application of AER’s expenditure forecast assessment guideline

We note the AER’s intention to apply its Expenditure Forecast Assessment Guideline to our forecast capex and opex for the forthcoming regulatory period.

20.5. Depreciation

We accept the AER’s proposed approach to use forecast depreciation to establish the regulatory asset base at the commencement of our subsequent regulatory period (i.e. 1 January 2021).

Our proposed approach to determining the depreciation building block for the forthcoming regulatory period is set out in Chapter 12.

20.6. Treatment of various jurisdictional and legacy issues

While we accept the application of the jurisdictional GSL scheme as set out in the Victorian Electricity Distribution Code we re-emphasise our views on this matter as set out in our July 2014 submission on the AER’s Preliminary Positions Framework and Approach.

Our submission highlighted that nature and scope of these payments have not been reviewed for many years. Therefore, and consistent with Council of Australian Government’s best practice regulatory principles, which emphasise the importance of ensuring that regulation is subject to periodic review, we support the transition to the AER’s national GSL scheme under the STPIS.

20.7. Non-traditional investment

In section 1.3.7 of the Final Framework and Approach paper the AER clarified the regulatory treatment of "non-traditional" investments on the customers' premises, behind the meter in response to a direct request from us. The AER stated that:

> *We do not consider it necessary to classify a service for non-traditional investments. This activity is directly concerned with the provision of network services, which is a classified service. Our expectation is that businesses will, in their day-to-day operations, consider the most efficient means of delivering regulated services. We consider that the rationale for an operating expenditure allowance or revenue adjustment is contingent on the business case for a particular investment. If the purpose of the investment is to efficiently deliver a network service, the expense should qualify as operating expenditure where the service is obtained through a contractual arrangement.*

The AER went on to add that:

> *investment by the NSP in assets installed within the customer's premises would continue to form part of a* distribution system *as defined in the NER.*

We welcome AER's clarification that:

- Services provided by non-traditional investment are not special types of services;
- Non-traditional network investment relates to Network Services;
- Assets that result from non-traditional investment form part of the distribution system (regardless of whether they are installed on the customers' premises behind the meter);
- Expenditure relating to non-traditional network investment needs to be justified on the same basis as any other standard control expenditure; and
- We can recover costs of non-traditional network investment through DUOS charges.

We have included non-traditional investments in our Augmentation capex (explained in section 10.10) where they provide more efficient investment solutions than traditional network investments. We have also revised our demand forecast explained in Chapter 9) in light of the impact of these non-traditional network investments.

21. Fee-based and quoted Alternative Control Services

Key messages:

- Alternative Control Services are classified as fee-based or quoted services.
- We have adopted the AER's proposed classification and price cap approach for regulating these services, which sets prices on the basis of forecast costs.
- Our proposed Alternative Control Services charges are based on a detailed bottom-up analysis of the costs of activities involved in providing the relevant services.
- We have used our actual costs in 2014 (the latest full year for which audited data is available) as the basis for forecasting 2016 Alternative Control Services costs. Our analysis shows that in 2014, the total costs of providing fee-based Alternative Control Services (excluding Reserve Feeder maintenance Alternative Control Services) exceeded total revenue by $3.37 million.
- 90 per cent of fee-based Alternative Control Services costs relate to services provided by competitively outsourced contracts. Therefore, our actual costs of providing fee-based Alternative Control Services in 2014 reflect the efficient costs of providing these services.
- Our fees must increase in 2016 to enable us to recover the efficient costs of providing Alternative Control Services.

21.1. Fee-based and quoted services

Fee-based and quoted Alternative Control Services include services such as:

- Providing a connection to a new property or increasing the capacity of an existing connection;
- Providing a temporary supply to a construction site;
- Elective undergrounding of an existing supply for single premises at the request of a customer where an overhead service exists;
- Testing the accuracy of a meter; and
- De-energising or re-energising supply when customers move premises.

In contrast to Standard Control Services, which are provided to all network customers, Alternative Control Services are customer-specific services. Accordingly, the costs of an Alternative Control Services can be attributed to, and recovered from, the customers who use the service. This pricing approach is both equitable and efficient. In particular, it encourages customers to weigh up the costs and benefits of requesting a service, and recovers the costs of the service from the appropriate customers.

As a customer-specific service, the costs of providing some types of Alternative Control Services will depend on the customer's particular requirements. For example, the costs of providing connection to customers > 100 amps cannot be known in advance of receiving the customer's specific request. In other instances, the Alternative Control Services is a standardised service, the costs of which can be estimated in advance of receiving a customer request. These observations lead to the categorisation of Alternative Control Services as follows:

- Quoted services, where prices are quoted according to the costs of meeting a customer's specific request; and
- A fee-based service, which is a tariff based on the costs of providing a standardised service.

The purpose of this chapter is to provide an overview of our proposed fee-based and quoted Alternative Control Services for the forthcoming regulatory period, and the methodology we have used to set these charges. Further detailed information, including the proposed charges, are set out in the supporting document, Fee-based and Quoted Alternative Control Services. The following Alternative Control Services are discussed separately:

- Revenue capped metering services, which are addressed in Chapter 18; and
- Public lighting services, which are addressed in Chapter 22.

21.2. Our proposed fee-based Alternative Control Services

21.2.1. Description

Fee-based Alternative Control Services are subject to price control regulation. As a consequence, the fee that we are able to charge for each service is fixed for the duration of the regulatory period. For equity and efficiency reasons, it is important that the assumptions and forecasts employed in setting the fee-based services are reasonable.

Table 21-1 describes the fee-based Alternative Control Services we propose to offer in the forthcoming regulatory period.

Table 21-1: Fee-based Alternative Control Services

Fee-based Alternative Control Services	Description of service
Routine connections - customers up to 100 amps	New connection of a customer <100 amps that does not require augmentation of the shared network.
Temporary supply services	Temporary supplies will be provided where supply is requested for a limited period. The most common request for such services relates to the supply of electricity to a construction site.
Field officer visits	These services involve the attendance of a field officer at the customer's premises to undertake an unscheduled meter reading at the customer's request.
De-energisation of existing connections	This service entails the removal of a fuse by service personnel at the customer's premises, to enable the de-energisation of the service connection to the premises.
Energisation of existing connections	This service entails the insertion of a fuse by service personnel at the customer's premises, to enable the energisation of the service connection to the premises.
Service Vehicle Visits (without inspection)	This service involves the attendance of a service crew in a service vehicle, to enable a customer to relocate or modify the existing service equipment installed at the customer's premises. Charges apply except for emergency and fault calls where the customer is not at fault.
Meter Equipment Test	This service involves the testing of meters to verify that they conform with applicable standards.
Remote AMI services	These services are outside the scope of the revenue capped AMI metering services. They include the fee-based services of Remote Meter Configuration; Remote Special Meter Reading; Remote Re-Energise; and Remote de-Energise.
AMI exit service	Where United Energy ceases to be the Responsible Person or Metering Coordinator for a metering installation that includes a remotely read interval meter, the exit service recovers the written down capital value and the operating costs of retiring that meter. Details of this service are provided in section 18.3.
Prescribed Metering Services (public lighting)	These are metering data services for unmetered supplies for public lighting only, and are provided exclusively to public lighting customers, such as retailers, municipal councils and Vic Roads. Details of this fee-based ACS are provided in section 22.2.

21.2.2. Approach to setting fee-based Alternative Control Services

This section describes our approach to setting charges for fee-based Alternative Control Services, with the exception of the following services:

- Prescribed metering services (public lighting), details of which are provided in section 22.2; and
- AMI exit services, details of which are provided in section 18.3.

Our approach to calculating fee-based Alternative Control Services is consistent with the standard cost-based regulatory approach. Our cost build-up for each Alternative Control Services includes the following components:

- External, directly attributable service provider costs. The arrangements under which our external service providers charge us for the services they provide have been subject to competitive tender and therefore reflect market rates. The relevant external service providers are ZNX, Tenix, Skilltech and Formway;
- External, directly attributable service provider costs for market and customer related back-office support. These costs are incurred in processing Alternative Control Services requests from customers and retailers. These costs are charged to us by our service provider (Aegis) at hourly rates specified in an agreement which has been subject to tender, so they reflect competitive market rates;
- Internal, directly attributable market and customer related back-office support costs incurred in the processing and oversight of Alternative Control Services;
- Internal, directly attributable corporate support costs relating to functions such as: accounting and accounts receivable; and
- A normal profit margin.

We have used our actual costs in 2014 (the latest full year for which audited data are available) as the basis for forecasting the costs of providing Alternative Control Services for the forthcoming regulatory period. Our analysis shows that in 2014, the total costs of providing fee-based Alternative Control Services (excluding Reserve Feeder maintenance Alternative Control Services) exceeded total revenue by $3.37 million. As 90 per cent of these costs are incurred through competitively let contracts, as noted above, our costs in 2014 are regarded as efficient.

Given the shortfall in cost recovery in 2014, our total revenue from fee-based Alternative Control Services must increase from 2016. In developing the proposed fees for 2016, we have undertaken a detailed cost analysis to determine cost-reflective fees for each service. Our proposed fees, along with further information on the application of our methodology are set out in the supporting document, Fee-based and Quoted Alternative Control Services, which is provided as an attachment to this Regulatory Proposal. As explained in that document, our proposed fees reflect the efficient costs of providing the services.

21.3. Quoted Alternative Control Services

As already noted, quoted Alternative Control Services arise where the costs of providing the service depends on the scope of a particular customer's service request. From a regulatory perspective, it is important that the methodology for pricing these services reflects the efficient costs of providing the service. The table below lists the quoted Alternative Control Services to be provided in the forthcoming regulatory period, and sets out a short description of each. The classification of our proposed quoted Alternative Control Services is consistent with those set out in the AER's Framework and Approach paper.

Table 21-2: Quoted Alternative Control Services

Quoted Alternative Control Services	Description of service
Rearrangement of network assets at customer request, excluding alteration and relocation of public lighting assets	Re-arrangement of our assets excluding public lighting at the request of a customer or other party. Such services are typically provided to enable customers or other parties to undertake construction work in the vicinity of our network assets.
Auditing design and construction	Provision of auditing and related services in relation to design and construction of electrical facilities, at the request of a customer.
Specification and design enquiry fees	Provision of information in response to a customer's request in relation to a connection or other inquiry.
Routine connections - customers above 100 amps	New connection of a customer >100 amps that does not require augmentation of the shared network.
High load escorts - lifting overhead lines	Temporary lifting of overhead lines to enable the safe passage of high loads.
After hours truck by appointment	After-hours attendance of a service truck in accordance with an appointment time requested by the customer.
Elective undergrounding where above ground service currently exists	Placing existing overhead assets underground at the request of a customer for a single premises.
Covering of low voltage lines for safety reasons	At the request of a customer or other third party, installation of safety covers on low voltage lines at construction sites.
Supply abolishment (>100 amps)	Disconnection and removal of supply service and associated metering equipment.
Reserve feeder	This service involves the provision of operation and maintenance of a reserve feeder or feeders at the request of a customer. In the current period it has been classified as a fee-based Alternative Control Services, but our practice has been to provide it as a quoted Alternative Control Services. From 2016, it will be classified as a quoted Alternative Control Services in accordance with the AER's reclassification, which will formalise the existing practice.

Typically, the prices for quoted Alternative Control Services will be based on quantities of labour, materials and other direct costs, with the quantities dependent on the particular task. Therefore, the AER's task is to set maximum labour hourly rates that should apply for the calculation of charges for Alternative Control Services offered on a quotation basis.

In developing our proposed rates for the forthcoming regulatory period, we have derived average labour rates by combining the unit rates from our competitively tendered contracts with ZNX and Tenix in respect of field labour, operational engineering, project planners and administrative support for quoted works. Full details of our proposed labour rates for the purpose of determining charges for quoted Alternative Control Services are set out in the supporting document, Fee-based and Quoted Alternative Control Services.

21.4. Demonstrating our prices are efficient

As explained in this chapter, our costs of providing fee-based and quoted Alternative Control Services are determined by competitively tendered contracts with external service providers. As explained in relation to our capex and opex forecasts, these contractual arrangements drive our service providers to deliver services efficiently. Our customers benefit from these efficiency improvements, because they are reflected in our actual costs.

Our forecasting approach for fee-based and quoted Alternative Control Services reflects the actual costs of providing these services in 2014, being the most recently completed year. The proposed increase in fees reflects the recovery of actual costs as recorded in the 2014 audited regulatory reporting. These costs are being under-recovered. It is appropriate that our future charges for Alternative Control Services properly reflect the efficient costs of providing these services, even if this requires an increase in charges compared to current rates.

The supporting document demonstrates that our Fee-based and Quoted Alternative Control Services hourly rates reflect the efficient costs of providing the services.

22. Public lighting

Key messages:

- We support the AER's proposed classification of public lighting assets. Specifically, the AER's approach limits price control regulation to the provision of shared public lighting assets.
- All other public lighting services, including those relating to greenfield and emerging technologies, will be classified as negotiated services. This classification will enable customers to negotiate terms and conditions with their DNSP or an alternative third party service provider.
- We have calculated a fee-based charge for shared public lighting assets in accordance with the AER's building block approach.
- On average, the proposed fees for 2016 will be approximately 15 per cent lower than the current (2015) fees in real terms, and will then increase by approximately 2 per cent per annum in real terms for the remaining four years of the forthcoming regulatory period.
- Further detailed information on the calculation of these charges is provided in the accompanying supporting paper.

22.1. Service classification and form of regulation

The AER's Framework and Approach paper classified public lighting services as shown in Table 22-1.

Table 22-1: AER's classification of public lighting services

Service	Classification
Operation, maintenance, repair and replacement - shared public lighting assets	Alternative control (fee-based)
Operation, maintenance and repair - dedicated public lighting assets	Negotiated
Replacement - dedicated public lighting assets	Negotiated
Alteration and relocation of DNSP public lighting assets	Negotiated
New public lights (that is, new lighting types not subject to a regulated charge and new public lighting at greenfield sites)	Negotiated

Source: AER

In adopting this classification, the AER accepted the points we raised in our submission to the AER's preliminary Framework and Approach paper. It is helpful to summarise the rationale for the proposed classification as follows:

- A distinction is made between assets dedicated to a particular customer (dedicated public lighting assets, in the sense of being a stand-alone assembly (i.e. public lighting assets that are separate from other distribution assets)) and luminaires connected to the shared distribution network (shared public lighting assets);
- Shared public lighting assets are regulated, principally because of safety issues associated with their connection to the distribution network. As a monopoly activity, it is appropriate for these services to be classified as Alternative Control Services;
- Shared public lighting assets are different in nature to dedicated public lighting assets – there is greater scope for competition to develop in the provision of dedicated public lighting assets;
- To maximise customer choice, flexibility and innovation it is useful to distinguish between the "replacement" and "operation, maintenance and repair" of dedicated public lighting assets;

- The separate classification of dedicated public lighting services allows customers to choose who maintains and repairs their assets and who replaces them. Furthermore, by classifying these services as “negotiated”, customers are able to negotiate terms and conditions from either the DNSP or a third party service provider;
- New public lighting, which includes emerging technologies and greenfield sites, are also classified as negotiated services unless that new public lighting is (or is to be) provided by shared public lighting assets as this raises the safety issues that generally apply to shared public lighting assets. This classification reflects the potential scope for customers to obtain services from third parties on a competitive basis; and

As already noted, we support the above classifications. For the purposes of this determination, the AER is only required to address the fee-based charges for the operation, maintenance, repair and replacement of shared public lighting assets. As the remaining services are classified as negotiated, the charges will be determined during the course of the regulatory period as terms and conditions are negotiated with our customers.

22.2. Fee-based charges for shared public lighting assets

The AER’s Framework and Approach paper sets out a formula for regulating the fee-based charges that will apply for shared public lighting assets. The formula requires that these charges should not increase annually by more than CPI-X, where X is to be defined through the distribution determination process.

In order to calculate the charges for shared public lighting assets in the first year of the forthcoming regulatory period, and their annual changes thereafter, the AER employs a public lighting spreadsheet model. This model adopts a building block approach, which determines our revenue requirements given the value of the assets, their remaining life, failure rates and our forecast opex and capex requirements. The resulting fees for the forthcoming regulatory period will be approximately 15 per cent lower than the current charges and will increase by approximately 2 per cent per annum.

The building block calculations are set out in the table below. For further information regarding the inputs to this model and the resulting fees, please refer to the supporting paper accompanying this Regulatory Proposal.

Table 22-2: Shared public lighting asset base for 2016 – 2020 ($M, Real 2015)

$M	2016	2017	2018	2019	2020
Opening Public Lighting Regulatory Asset Base	19.7	20.8	21.9	23.0	24.1
Capex	2.4	2.5	2.6	2.6	2.8
Less regulatory depreciation	1.3	1.4	1.4	1.5	1.6
Less the capital component of the exit fees	-	-	-	-	-
Closing Regulatory Asset Base	**20.8**	**21.9**	**23.0**	**24.1**	**25.3**

Table 22-3: Building block calculation for shared public lighting ($M, Real 2015)

	2016	2017	2018	2019	2020	Total
Return on Capital	1.6	1.7	1.8	1.9	2.0	9.0
Depreciation	1.3	1.4	1.4	1.5	1.6	7.2
Opex	3.7	3.7	3.8	3.8	3.8	18.8
Estimated cost of corporate income tax	-	-	-	-	-	-
Total Revenue Requirement (unsmoothed)	**6.6**	**6.8**	**7.0**	**7.2**	**7.3**	**34.9**

23. Negotiating Framework

Key messages:

- We have updated our current Negotiating Framework for the changes in service classification.

Our Negotiating Framework has not changed from that which has applied during the current regulatory period, except to make changes to the description of negotiated distribution services to reflect the AER's Framework and Approach Paper in relation to public lighting services and the construction of a reserve feeder. In addition, some consequential and minor drafting changes have been made to change our address and to delete definitions not used in the document. Our Negotiating Framework meets the requirements of clause 6.7.5 of the Rules.

We expect the AER will determine Negotiated Distribution Service Criteria as set out in our distribution determination for the current regulatory period (at Appendix D) and our Negotiating Framework is consistent with those Criteria.

24. Confidentiality

In accordance with the Rules and the AER's Confidentiality Guideline, we have completed a confidentiality template that we have provided to the AER as an attachment to our Regulatory Proposal. This details the matters in our Regulatory Proposal and supporting documents for which we are claiming confidentiality.

25. Certifications

25.1. Certification statement

Schedules 6.1.1(5) and 6.1.2(6) of the Rules require us to provide a certification by our Directors about the key assumptions that underlie our capex and opex forecasts.

The certification statement is provided as an attachment to this Regulatory Proposal.

25.2. Chief Executive Officer statutory declaration

The Reset RIN requires our Chief Executive Officer to provide a statutory declaration about the information that we have provided to the AER.

The statutory declaration is provided as an attachment to this Regulatory Proposal.

25.3. Board resolution

The Reset RIN requires us to provide a Board resolution about the information that we have provided to the AER.

The Board resolution is provided as an attachment to this Regulatory Proposal.

26. Glossary

Abbreviations	
ACIF	Australian Construction Industry Forum
ACR	Automatic circuit reclosers
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
AMS	Asset Management System
AOC	Actual Outturn Costs
Augex	The AER's Augex model
Bp	basis points
bppa	basis points per annum
BST	Base-Step-Trend
BVAL	Bloomberg Valuation
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
CBD	Central Business District
CCC	Customer Consultative Committee
CEO	Chief Executive Officer
CESS	Capital Expenditure Sharing Scheme
CFO	Chief Financial Officer
CIRB	Capital Investment Review Board
COWP	Capex and Opex Works Program
CPI	Consumer price index
CROIC	Victorian Government Cost Recovery Order-in-Council
DAPR	Distribution annual planning report
DDM	Dividend discount model
DESS	District Energy Services Scheme

Abbreviations	
DMIA	Demand management incentive allowance
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
DRP	Debt risk premium
DUOS	Distribution use of system
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity distribution price review
EE	Energy efficiency
ENA	Energy Networks Association
ERP	Enterprise Resource Planning
ESCV	Essential Services Commission of Victoria
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
EV	Electric vehicle
EWOV	Energy and Water Ombudsman Victoria
FAB	Franking account balances
F-factor	Victorian Government Fire-factor scheme
FVC	Fair value curve
GM	General Manager
GSL	Guaranteed Service Level
GWh	Gigawatt Hour
ICT	Information and Communications Technology
LCS	Life Cycle Strategies
LED	Light Emitting Diode
LTIFR	Lost Time Injury Frequency Rate
M	Millions
MAIFI	Momentary average interruption frequency index
MAIFIe	Momentary Average Interruption Frequency Index event

Abbreviations	
MCR	Marginal cost of reinforcement
MEPS	Minimum energy performance standards
MoU	Memorandum of understanding
MRP	Market risk premium
MTFP	Multilateral Total Factor Productivity
MVA	Mega Volt Ampere.
MW	megawatt
NBNCo	National Broadband Network Company
NECF	National Energy Customer Framework event
NEFR	National Electricity Forecasting Report
NEL	National Electricity Law
NEM	National Energy Market
NEO	National Electricity Objective
NER (Rules)	National Electricity Rules
NST	Neutral Supply Test
OMR&R	Operation, maintenance, repair and replacement
OMSA	Operational and Management Services Agreements
Opex	Operating expenditure
PFP	Partial Factor Productivity
PoE	Probability of Exceedence
PTRM	The AER's Post-Tax Revenue Model
PV	Photovoltaic
RCGS	Remote control gas switches
REFCLs	Rapid Earth Fault Current Limiters
Repex	The AER's Repex model
RFM	The AER's Roll-forward Model
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test – Distribution

Abbreviations	
ROE	Return on equity
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition
SEO	Seasoned equity offering
SFA	Stochastic frontier analysis
SG	State Grid Corporation of China
SGSPAA	SGSP (Australia) Assets Pty Ltd
SP	Singapore Power Limited
STPIS	Service Target Performance Incentive Scheme
Tenix	Tenix Australia Pty Ltd
TFP	Total Factor Productivity
TOC	Target operating costs
TSDF	Terminal Station Demand Forecast
UE	United Energy
VBRC	Victorian Bushfires Royal Commission
VCR	Value of Customer Reliability
VEET	Victorian Energy Efficiency Target
VPP	Virtual power plant
WACC	Weighted average cost of capital
WPI	Wage Price Index
WTP	Willingness to pay

27. Supporting documentation

We have provided to the AER an attachment that lists the documents that are referred to in this Regulatory Proposal and are incorporated within, and form a part of, it. Further documents may be referred to in the listed documents and these too are incorporated within, and form a part of, this Regulatory Proposal.

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