REGULATORY PROPOSAL TO THE AUSTRALIAN ENERGY REGULATOR

DELIVERING BETTER VALUE

1 JULY 2015 – 30 JUNE 2019

Endeavour Energy

TABLE OF CONTENTS

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This proposal outlines how Endeavour Energy plans to operate and maintain its electricity network in an efficient manner to keep it safe, reliable and affordable for our customers. The proposal includes the funding needed to deliver these services.

The Australian Energy Regulator (AER) administers the National Electricity Rules (NER) or (Rules) which determine the revenue required by electricity distributors in the National Electricity Market (NEM) to recover the costs of network investments and operations.

New South Wales (NSW) and Australian Capital Territory (ACT) electricity distribution businesses were due to submit their proposals covering the period from 1 July 2014 to 30 June 2019. However, in 2012 the Australian Energy Market Commission (AEMC) consulted the industry and wider community about major proposed alterations to the Rules, and subsequently made a number of important changes. The NSW and ACT distribution network businesses are the first organisations to submit proposals under the new Rules.

During the consultation period the AEMC decided that a one-year transitional proposal would help distributors make the move to the new Rules, particularly given the short period available to NSW and ACT businesses to prepare their submissions after the rule change came into effect. The transitional proposal would cover the period 1 July 2014 to 30 June 2015. It is a described as a “placeholder” proposal.

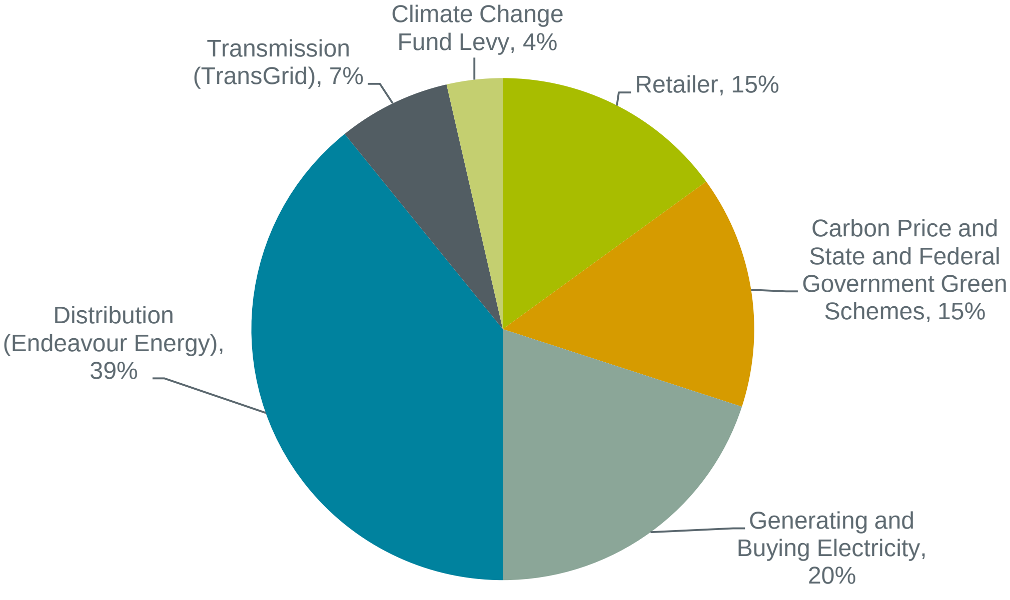
The full substantive regulatory proposal, covering the entire five-year period from 1 July 2014 to 30 June 2019 (2014-19), was to be submitted some months after the transitional regulatory proposal, and would provide full details of forecast capital and operating plans and revenue requirements. Endeavour Energy presented its transitional proposal on 31 January 2014.

The AER made a determination on Endeavour Energy’s transitional regulatory proposal on 16 April 2014. The document presented here is Endeavour Energy’s substantive regulatory proposal.

Explaining our role

Endeavour Energy builds, maintains and operates the electricity distribution network in Sydney’s Greater West, the Blue Mountains, Southern Highlands, Illawarra and South Coast of NSW. This requires the investment of hundreds of millions of dollars each year. Our charges are provided to electricity retailers and, when combined with TransGrid’s transmission charges, represent about 46% of a residential customer’s electricity bill. On average, a customer’s total electricity charges break down into the components shown in Figure 1.

Figure 1: Components of your electricity bill



EXECUTIVE SUMMARY

NSW Government network reform program

In March 2012 the NSW Government announced a restructure of Ausgrid, Endeavour Energy and Essential Energy, the three NSW electricity distribution organisations. The restructure commenced on 1 July 2012 with three objectives:

- To continuously improve safety performance for employees, contractors and the public.
- To maintain the reliability and sustainability of the electricity distribution networks.
- To strive to contain average increases in our share of customers' electricity bills to at or below CPI (consumer price index).

The network reform program focused on applying better strategic, operational and financial discipline to both the capital and operating programs. This is projected to deliver total business savings of $5.4 billion over the five-year period commencing July 2011.

Endeavour Energy's efficiency and productivity program

Ahead of this reform program, Endeavour Energy promised its customers it would do all it could to limit increases in its share of customers' electricity bills. We embarked on an efficiency and productivity program which saw our network prices for an average residential customer increase by just 0.1% on July 2013.

This achievement is the direct result of our collective efforts to find cost savings, improve productivity and realise efficiencies totalling $180 million since July 2009. It also reflects our success in delivering on our voluntary commitment to the AER to reduce our operating costs by 2% a year from July 2009 to June 2014. A commitment that was reflected in the AER Determination for 2009-14.

The combined benefits of our efficiency program and the NSW Government's network reform program are included in this regulatory proposal and will result in lower distribution network charges for customers.

More details about the results of the reform driven initiatives in reducing business costs and increasing operational efficiencies can be found in Attachment 0.02.

Highlights of our substantive proposal

Endeavour Energy is proposing a 5% reduction in revenue requirements over the five year period covering our substantive regulatory proposal. This will directly translate into an average distribution network price reduction of 6% in real terms for a typical residential customer from 2014 to 2019.

Table 1: Annual revenue requirement

$m; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Annual revenue requirement	1,021.7	1,021.6	1,046.1	1,067.9	1,101.1	**5,258.3**

EXECUTIVE SUMMARY

Table 2: Bill impact from our network charges for typical residential and small business customers (including metering)

%; Nominal [Bill Increase] – including metering	2014-15	2015-16	2016-17	2017-18	2018-19
Residential customer consuming 5MWh p.a.	1.21%	1.82%	1.22%	1.22%	1.22%
Small business customer consuming 26MWh p.a.	1.21%	1.82%	1.22%	1.22%	1.22%

These real reductions (i.e. less than inflation) are driven by substantially lower capital requirements and operational efficiencies pursued by Endeavour Energy since 2009 and as a result of network reform program initiatives.

They are also a result of lower borrowing costs following the Global Financial Crisis. As a result, Endeavour Energy is proposing a weighted average cost of capital of 8.83% applied to the 2014-19 period, compared to the rate of 10.02% for the previous regulatory period.

Table 3: Proposed capital expenditure and operating expenditure requirements

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Capital expenditure[1]	432.9	361.1	314.3	325.7	312.0	**1,746.1**
Operating expenditure[2]	267.6	272.4	281.2	278.7	284.4	**1,384.3**

The five year capital program will reduce from $3.0 billion approved by the AER for the 2009-14 regulatory period to a proposed $1.9 billion for the 2014-19 period[3] – a reduction of 36%, which is 43% below the forecast rate of inflation over the five year period.

The five year operating program will increase from $1.6 billion approved by the AER for the 2009-14 regulatory period to a proposed $1.8 billion for the 2014-19 period[4] – an increase of 10%, which is 2% below the forecast rate of inflation over the five year period.

We expect, on average, our customers will continue to reduce electricity usage by an average of 1.6% per annum over the five years commencing 1 July 2014. This is due to:

- the continuing take-up of domestic solar panels
- the high Australian dollar's impact on Australian manufacturing
- greater penetration of energy efficient appliances
- changing consumer behaviour in response electricity price increases from July 2009 to July 2012.

We expect that current network reliability will be maintained for the regulatory period based on capital and operating expenditure requirements.

[1] This proposed capital expenditure relates to standard control services and excludes alternative control services.

[2] This proposed operating expenditure relates to standard control services inclusive of Demand Management Incentive Allowance and debt raising cost amounts.

[3] For comparison, this proposed expenditure is inclusive of ancillary network services and metering. To give effect to the AER's 2014-19 classification of services, amounts in the remainder of this document will be exclusive of ancillary network services and metering unless otherwise stated.

[4] See above. These amounts are also exclusive of amounts relating to the retail pass-through, the Demand Management Incentive Allowance and debt raising costs.

EXECUTIVE SUMMARY

Engaging better with our customers and stakeholders

The AER's new consumer engagement guidelines encourage all network businesses to better align their day to day operations with the long term interests of end-use consumers.

Endeavour Energy has tradition of engaging with its customers, communities and stakeholders via community consultation, advocacy programs, face to face briefings, research, meetings, and presentations.

In the lead up to this regulatory submission, Endeavour Energy undertook its most comprehensive engagement program to date, based on best practice engagement principles.

Endeavour Energy developed its own customer engagement plan (Attachment 2.01) to guide our approach to inform, involve and collaborate with customers and stakeholders on our regulatory proposal.

These strategies will be continually reviewed to determine which engagement strategies have worked and which ones should be incorporated into long term business activities. By giving customers greater opportunities to communicate with us, we hope that we can learn more about their views and better align our operations to their long term interests.

More details about our customer engagement activity can be found in Chapter 2: Our Customers and our customer engagement plan can be found at Attachment 2.01 To help provide greater transparency and facilitate better engagement, Endeavour Energy has also created a dedicated web page[5] to house all our relevant regulatory documents and the results of our consumer engagement activity.

[5] www.endeavourenergy.com.au/ourplans

ABOUT THIS PROPOSAL

This document is Endeavour Energy's substantive regulatory proposal for the period 1 July 2014 to 30 June 2019. It sets out the revenue requirements needed to manage the network in a safe, reliable and efficient manner for our customers. It differs in a few key respects from previous regulatory proposals submitted to the AER.

It should be read in conjunction with Endeavour Energy's Transitional Regulatory Proposal, which covers a single year from July 2014 to June 2015 and determined by the AER on 16 April 2014.

We have also developed an overview paper[6] that contains a plain English summary for customers and stakeholders (Attachment 0.01). This document is designed to be more accessible to our customers and stakeholders, who may not be use to the complex area of electricity regulation and compliance.

This approach is consistent with the wishes of the AER and its new customer engagement guidelines. Although the guidelines are non-binding, we agree that they will assist customers' understanding of our regulatory proposals, our plans and the way we manage the electricity network.

By giving customers greater opportunities to communicate with us, we hope that we can learn more about their views and better align our operation to their long term interests.

Proposal layout

This proposal contains the following chapters:

- Executive Summary
- Chapter 1 – About Endeavour Energy
- Chapter 2 – Our customers
- Chapter 3 – Services and price controls
- Chapter 4 – Building block proposal
- Chapter 5 – Capital expenditure
- Chapter 6 – Operating expenditure
- Chapter 7 – Allowed rate of return
- Chapter 8 – Alternative control services
- Chapter 9 – Pricing arrangements and negotiated framework

Supporting documents

We have also included a suite of supporting documents which substantiate our regulatory proposal, and addresses compliance obligations within the proposal. They include:

- This proposal document.
- The Plain English language overview for our customers.
- All supporting documents that we have submitted to substantiate our proposals. We have organised our supporting documents so that they relate to a chapter and/or section of our proposal.
- Our response to the RIN issued by the AER on 7 March 2014.
- Completion of the AER's pro-forma confidentiality template, as required under its Guidelines.

[6] Clause 6.8.2(c1) of the NER

ABOUT THIS PROPOSAL

Feedback on this proposal

Endeavour Energy's customers and stakeholders can provide feedback on this report through the following channels:

Channel	Details
Email	yoursay@endeavourenergy.com.au
Post	Chief Operating Officer PO Box 811 Seven Hills NSW 1730
Online	www.endeavourenergy.com.au/contactus

Customers can also provide feedback and comments on our proposal to the AER (www.aer.gov.au).

Alternatively, customers may also like to contact us via Twitter.com/endeavourenergy.

Other ways to comment

Endeavour Energy, Ausgrid and Essential Energy have also jointly launched a Facebook page (www.facebook.com/YourPowerYourSay) to engage customers on a wide variety of topics ranging from prices and reliability to vegetation management and street lights. We are also now seeking customer feedback about our regulatory proposals on the joint Facebook page.

your power, your say

1 ABOUT ENDEAVOUR ENERGY

Summary

Endeavour Energy is a New South Wales state owned energy corporation serving some of the largest and fastest growing regional economies in the state.

We manage a $5.6 billion electricity distribution network for 908,000 customers, or 2.2 million people, in households and businesses across an area spanning 24,500 square kilometres in Sydney's Greater West, the Blue Mountains, Southern Highlands, Illawarra and South Coast of NSW.

Our network includes Sydney's North West and South West Growth Centres – areas similar to Wollongong and Canberra in size, and earmarked by the NSW Government for current and future housing development.

Between them, these centres cover 27,000 hectares and will become home to more than 500,000 people in more than 180,000 dwellings.

We are preparing to meet this extra growth and maintain our existing infrastructure by prudent investment in our network during the next regulatory period.

Over the past few years, we've kept a strong focus on improving our safety performance, maintaining the reliability of our network and more recently containing our share of electricity cost increases for our customers.

Endeavour Energy recognises that electricity affordability has been a key issue for customers.

For this reason, in 2009 we embarked on an efficiency and productivity drive which last year saw our network prices for an average customer increase by just 0.01% on 1 July 2013. This marked the first time in a decade network prices fell below inflation.

This achievement was due to the determination of our 2,650 people to find cost savings, improve productivity and realise efficiencies totalling $180 million since July 2009. It also marks our success in delivering on our voluntary commitment to the AER to reduce our operating costs by 10% from July 2009 to June 2014.

Our customers continue to be central to our plans. We're committed to making a serious and sincere effort to deliver better value for customers by reducing our costs, without compromising safety or services.

Figure 2: Endeavour Energy's franchise area

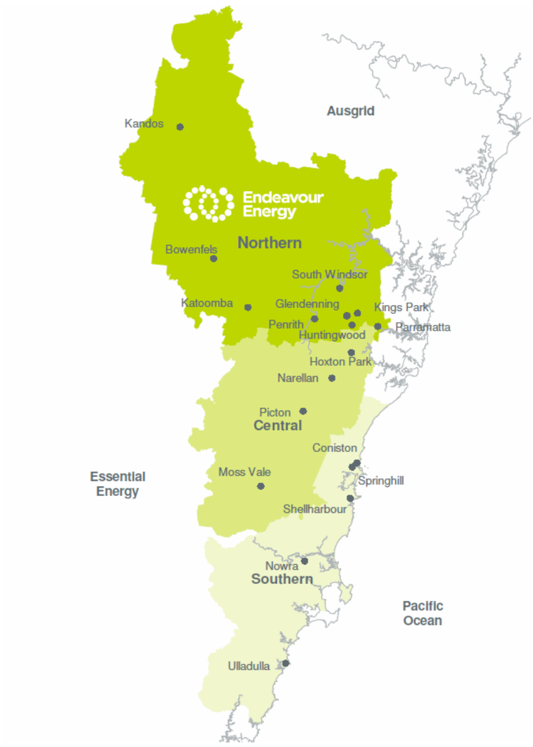
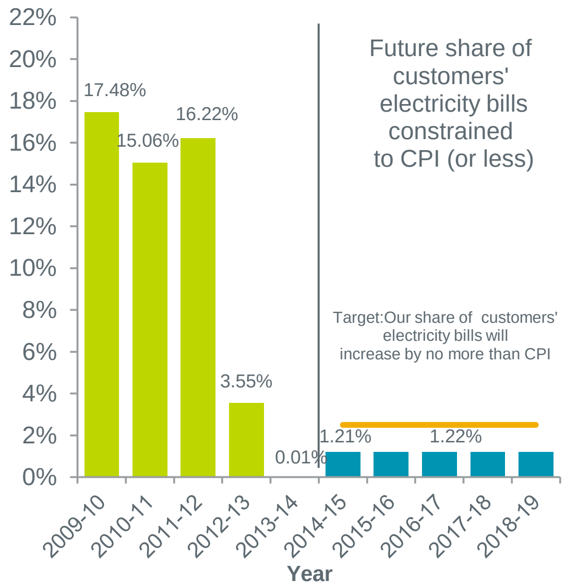


Figure 3: Movement in our share of electricity bills (nominal %)



1 ABOUT ENDEAVOUR ENERGY

Our business

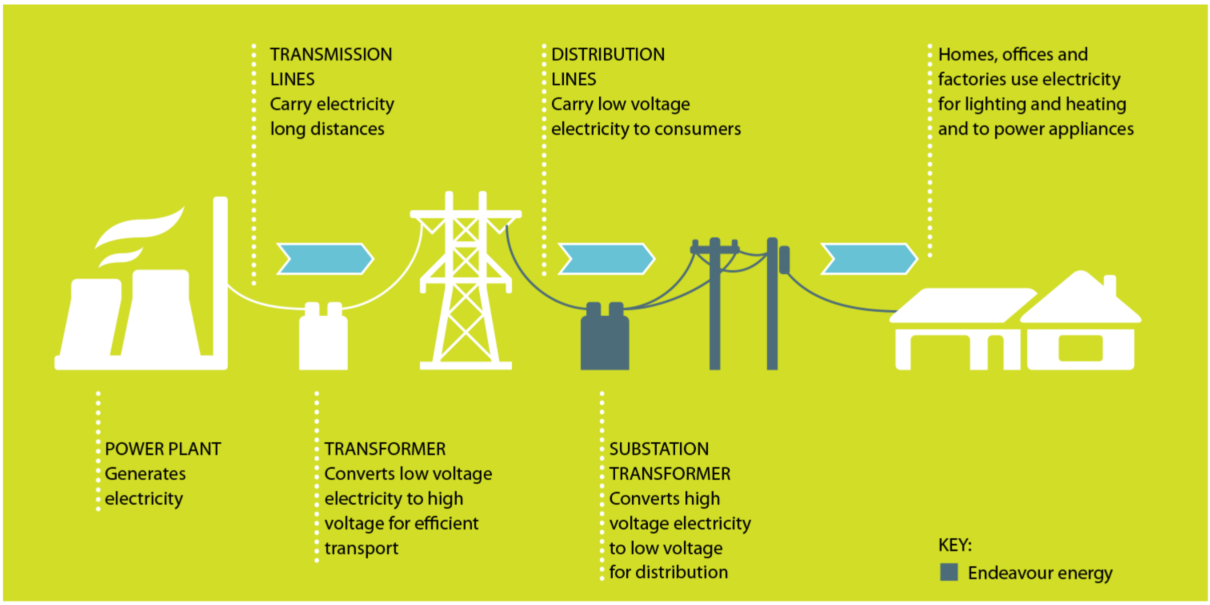
Endeavour Energy builds and operates the network that transports electricity from the high voltage transmission system to customers' homes and businesses. We are one of three electricity distribution businesses operating in NSW.

Power plants typically generate electricity a long way from homes and businesses. It is then transported at high voltages over the transmission system to Bulk Supply Points operated by TransGrid. Endeavour Energy's distribution system then transports it to 22 sub-transmission and 155 zone substations. Zone substations typically service entire suburbs and transforms electricity to mid voltage levels (11kV).

When electricity arrives where it is required, 30,000 distribution substations further transform it to 415V or 240V. Low voltage electricity is delivered to consumers' homes and businesses via 413,000 power poles and 35,000 km of overhead and underground powerlines.

As a 'poles and wires' business, we also restore power after storms, read and maintain electricity meters, keep trees away from power lines and design and maintain street lights for local councils.

Figure 4: Electricity industry structure, Source: AEMO



Network characteristics

Aside from areas of rapid growth, Endeavour Energy's network features other characteristics which drive investment requirements. They include:

- Temperature extremes: peak temperatures across the network are often 10 degrees higher, and stay higher for longer, than Sydney's CBD and coastal areas. This requires more investment to meet consumer demand on the few hottest days of the year.
- Air-conditioning: around 72% of homes across our network have an airconditioner. Penetration varies significantly. In Greater Western Sydney 81% of households use airconditioning, while it is used in 59% of homes in the Illawarra and 40% of homes in the Blue Mountains.

- Appliances: televisions, in-home computers and entertainment systems have changed consumption patterns and heightened customers' expectations and awareness about reliability and security of supply.

These characteristics have been the main driver of our network strategy for the current regulatory period.

Our vision

Endeavour Energy's vision is to be of service to our communities by efficiently distributing electricity to our customers in a way that is safe, reliable and sustainable.

Our business plan sets out our priorities and actions to deliver this vision and promote the long term interests of our customers, our people and our shareholders.

We have centred our efforts over the past five years on three key objectives:

- to continuously improve safety performance for employees, contractors and the public
- to maintain the reliability and sustainability of the electricity distribution networks
- to strive to contain average increases in our share of customers' electricity bills at or below the Consumer Price Index (CPI).

Safety outcomes

Safety is our number one priority. We seek to encourage a culture where no employee knowingly participates in an unsafe act.

Although we are not yet at safety best practice, we have seen an improving trend over the last five years. We have renewed our efforts to embed a safety culture by:

- encouraging more reporting of incidents and early medical intervention
- continued use of the Incident Cause and Analysis Method to understand incidents and plan corrective actions
- updating our consultation processes
- implementing our Lifeguard program to minimise the risk of a worker affected by alcohol, drugs or fatigue causing injury or death.

Further cultural change is planned to make the network as safe as possible and ensure that all our people are free from harm in the workplace and return home in good health.

Reliability outcomes

Customers are benefiting from a more reliable and sustainable electricity supply than five years ago. Our substantial network investment program and targeted reliability improvement projects have made our network more reliable and more resilient.

We measure network reliability with the System Average Interruption Duration Index (SAIDI). This measures the number of unplanned minutes customers, on average, are without electricity each year, excluding the impact of significant storms. SAIDI improved from 126 minutes in 2003–04 to 88 minutes by the end of June 2013. This means the reliability of Endeavour Energy's network is consistent with those of other Australian networks.

By July 2014 we will have largely completed the major network investments needed to meet NSW Government licence conditions. This means capital expenditure will shift over the next five years from peak demand driven projects to replacing ageing assets to maintain network reliability. The total capital program will decline by about 43% in real terms compared to our allowance for 2009-14.

1 ABOUT ENDEAVOUR ENERGY

" Anything Endeavour Energy is doing to keep costs down is welcome"

Consumer at Penrith forum[7]

Pricing outcomes

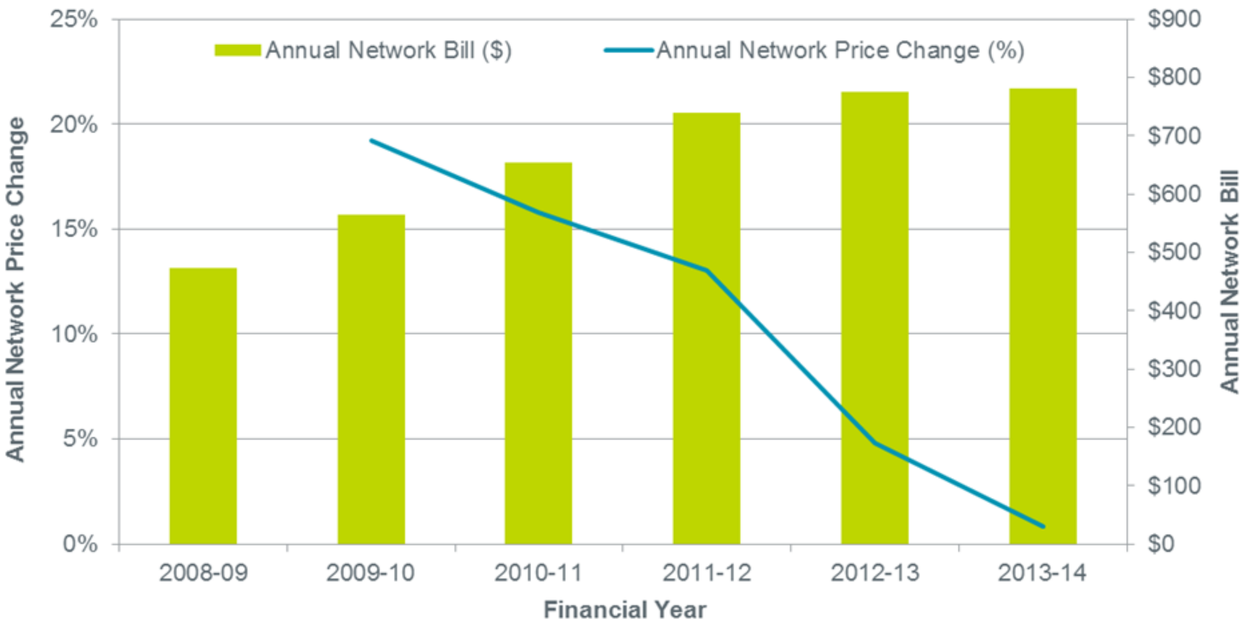
Since 2009 retail electricity prices rose steeply across Australia due to significant investment in electricity networks and increases in labour and operating costs, as well as the introduction of the carbon tax and rising retail costs. For Endeavour Energy customers, this meant average network price increases of 41% in real terms since July 2009.

To assist in addressing electricity affordability, in 2009 Endeavour Energy made a commitment to reduce the cost of running its business by 10% over five years. This commitment was built into the AER Determination for 2009-14. Since July 2012 we have focused on delivering a series of efficiency programs to help keep price increases at or below the rate of inflation without compromising the safety or the reliability and sustainability of our network.

We've kept our promise to customers to do all we can to limit increases in our share of the customer's bill. July 2013 marked the first time in a decade that average increases in Endeavour Energy's network charges fell below inflation, a pattern expected to continue for the next five years.

The cumulative effect in declining rate of change in network prices for Endeavour Energy's customers since 2009 is shown below:

Figure 5: Increase in annual Network bill (NUOS) for typical Endeavour Energy residential customer (2009-14)



7 Attachment 2.06: Consumer engagement report, April 2014

1 ABOUT ENDEAVOUR ENERGY

Key events over the current regulatory period

Five key events during the regulatory period to June 2014 influenced our performance and changed our business.

These events included: implementation of Endeavour Energy's efficiency program; the NSW Government's network reform program; our capital delivery strategy; the prolonged impact of the Global Financial Crisis (GFC); and the sale of our retail business. Each influenced the cost of servicing our customers.

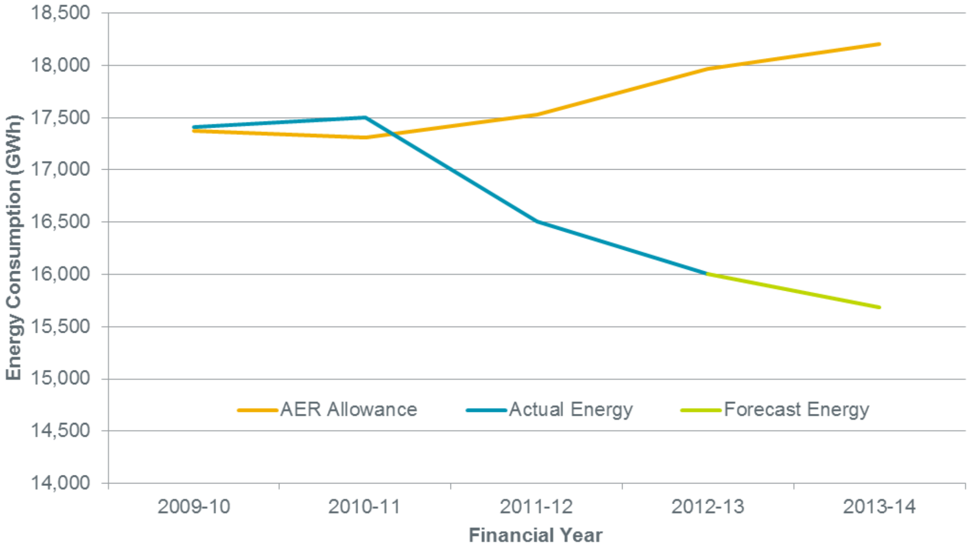
Network reform has accelerated the pace at which we are achieving our efficiency goals. The benefits of the NSW Government's network reform program and our efficiency programs are outlined in this substantive regulatory submission and will help to meet the long term interests of our customers.

We have reviewed our capital program and reduced operating expenditure in order to minimise future network bill increases. We have deferred capital expenditure where appropriate, and improved our efficiency in delivering capital projects. We've adopted a blended delivery approach using a mix of internal and external resources, resulting in a significant percentage of market-tested and externally sourced investment.

By sourcing network investment from the market, we achieved savings of around 10-15% for capital projects, compared to the period 2004-09. We did more, with less, which means we are now in a strong position to reduce our capital expenditure during the next regulatory period.

Electricity consumption across our network declined over the past four years due to changing consumer behaviour in response to price increases, a high Australian dollar, the continuing economic slowdown, the carbon tax, relatively mild winter and summer seasons, an increase in rooftop solar systems, and energy efficient appliances and efficiency schemes.

Figure 6: Electricity consumption (GWh)



Finally, our former retail business, Integral Energy, was sold to Origin Energy on 1 March 2011. The transition of the customer data and relevant services associated with this sale were completed at the end of January 2013. The sale resulted in what is known as stranded costs (investments already made and benefits not fully realised) and the loss of the ability to share fixed corporate overhead costs.

During the regulatory period, the potential reallocation of corporate overhead costs to standard control services arising from the retail sale became known. Our efficiency initiatives ensured that the resultant forecast operating expenditure did not exceed the approved 2013-14 operating expenditure allowance in real terms, despite the material reallocation of costs recognised by the AER in its pass-through decision, Attachment 6.12.

1 ABOUT ENDEAVOUR ENERGY

Current period performance

Our customer value improvement program (CVIP) sought to reduce costs by minimising waste and finding new ways to add value for our customers at no additional cost.

In 2012-13, Project Challenge and Project Compete, two of our efficiency improvement initiatives, delivered over $20 million in ongoing savings.

Project Challenge focused on reducing corporate overheads through a series of initiatives. Project Compete focused on reducing network operating costs through improvements in our workforce delivery model, scheduling processes and standardising work practices, set up the framework for savings that will be realised in 2013-14. This means that collectively we are on track to achieve our overall savings target of $48 million per year by June 2014.

We delivered a peak capital investment program during 2009-14, driven largely by the need to replace ageing assets, meet the NSW Government's new licence and reliability conditions, and respond to significant forecast demand growth.

We also sought to maintain the reliability and quality of our supply by replacing ageing assets and increasing network capacity for new customers. The program has significantly improved the resilience of our network to extreme weather, natural disasters, and peak demand conditions.

We responded to the peak challenge of network investment by a strategy of peak resourcing from the private sector. The strategy combined external contractors with our own employees for both program delivery and management. This approach will continue to be employed to achieve efficient, flexible and sustainable customer delivery for future periods.

> *" I hope your plans also consider future proofing, eg. capacity and load with increased technology"*

Consumer at Wollongong forum[8]

Our future investment focus

By 2014, we will have largely completed the major network investments needed to meet our licence conditions. This means capital expenditure will shift in focus over the next five years from peak demand-driven major projects to maintaining network reliability by replacing ageing assets.

When managing our network we have to balance costs, reliability standards and customer benefits. To achieve this, we will continue to combine internal and external resources to produce the most efficient outcome for customers. Improving our productivity, applying best practice asset management principles and leveraging technology are central to our success.

Our Investment Governance Framework is designed to drive investment efficiency across NSW. It means that new asset replacement criteria, reliability risk tolerance and risk mitigation strategies are being applied consistently across NSW, and ensures that every dollar spent is prioritised to deliver a safe, reliable and efficient network.

To maintain our network's reliability we will deliver the capital investment and maintenance tasks outlined in our Asset Management Plan. We will improve the tools we use to determine the cause of incidents and develop initiatives to meet service standards. We will also undertake targeted initiatives to safely improve reliability without increasing customers' bills.

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[8] Attachment 2.06: Consumer engagement report, April 2014

1 ABOUT ENDEAVOUR ENERGY

Our future investment focus is built around the following themes:

- servicing growth in demand – we will aim to meet customers' demand for electricity through a balance of investment in building a network of adequate capacity and managing the demand on the network through the use of non-network alternatives
- providing customers with choice about how their demand is managed
- being a capable and prudent asset manager, and a trusted and credible network operator
- ongoing improvements to our delivery model for our capital and maintenance programs, targeting greater flexibility and efficiency.

Our values

Endeavour Energy is committed to fostering a workplace culture that delivers the highest standards of safety, respect and integrity for workers and the customers and communities we serve. Our employees are required to understand and behave in a manner that supports our values as outlined below.

Safety excellence

- Put safety as your number one priority
- Do not participate in unsafe acts, and challenge unsafe behaviours
- Think before you act
- Lead by example
- Take responsibility for the health and safety of yourself and others

Respect for people

- Treat all people with respect, dignity, fairness and equity
- Demonstrate co-operation, trust and support in the workplace
- Practise open, two-way communication

Customer and community focus

- Deliver value and reliable service to our customers and communities
- Use resources responsibly and efficiently
- Be environmentally and socially responsible

Continuous improvement

- Look for safer and better ways to do your job
- Improve our financial performance
- Support innovation to add value to our business

Act with integrity

- Act honestly and ethically in everything you do
- Be accountable and own your actions
- Follow the rules and speak up

2 OUR CUSTOMERS

Summary

Endeavour Energy's 908,000 customers include 824,000 residential customers, 80,000 small business customers and 5,000 large customers with annual electricity consumption in excess of 160 MWh per annum.

Most of our customers are households and small to medium businesses located in urban and surrounding rural areas. We also serve large urban centres, medical precincts and manufacturing and industrial customers that need a large and secure electricity supply.

Our stakeholders include energy retailers, government, local councils, chambers of commerce, accredited service providers, industry associations, suppliers, media outlets, industry commentators, consumer advocacy groups and educational institutions.

Our customer focus

Endeavour Energy's long standing commitment to its customers and communities requires us to create value; deliver reliable services; use resources responsibly and efficiently; and be environmentally and socially responsible.

We believe our commitment is central to the long term interests of our customers and the communities we serve, and to our business success.

For many years, Endeavour Energy has informed, consulted and engaged with its customers and communities on issues of mutual interest. We have:

- measured customer satisfaction about our operations
- assessed perceptions and interests of key stakeholders
- shaped final products and services based on customer input
- consulted with customers and stakeholders on key infrastructure projects
- worked with retailers to generate better outcomes for end use customers.

We support the renewed focus given to the nature, quality and extent of our engagement with consumers by the AEMC and the AER and we are committed to embedding consumer engagement in our day to day operations.

Our customer engagement plan

Endeavour Energy has developed a plan (Attachment 2.01) for the way we engage with our customers and communities and has used the outcomes of the initial stages of the strategy to guide the development of this proposal.

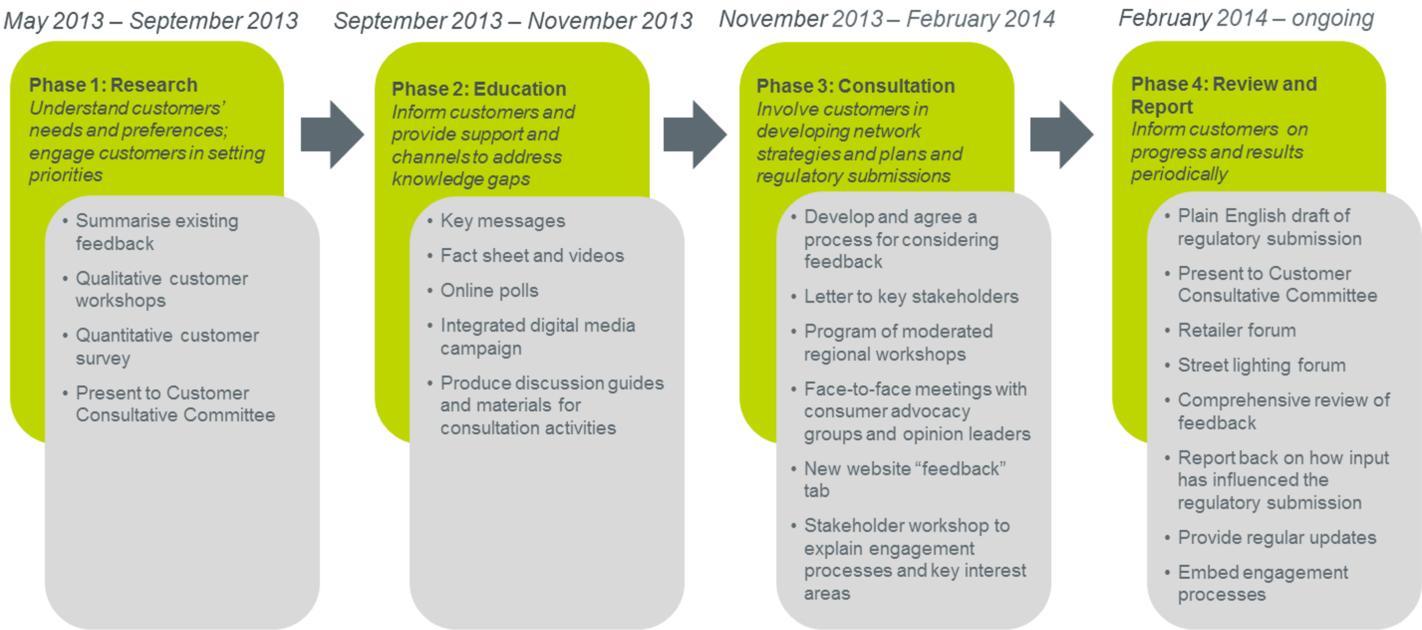
Our engagement approach is based on best practice community engagement principles set out by the International Association of Public Participation. We've used these principles since 2008 for other community engagement projects and have used them again to:

- Inform customers about our work.
- Consult customers on issues where there are different opinions and choices.
- Involve customers in shaping our plans and services through research, consumer forums and product trials.
- Collaborate with stakeholders and consumer representatives on issues of broad concern. Examples of this includes how we charge for street lighting and construct electricity tariffs.

2 OUR CUSTOMERS

The diagram below outlines the key activities in Endeavour Energy's customer engagement plan:

Figure 7: Customer engagement plan



Customer and stakeholder objectives

The plan was designed to deliver the following important objectives:

- research consumers' perceptions, needs, interests and priority areas for consultation
- raise awareness of our engagement process within and outside of regulatory periods and work to improve and embed effective engagement channels
- provide relevant information to customers and stakeholders to improve their understanding of the factors that impact network prices and build their capacity to provide meaningful feedback
- offer a broad range of communication and engagement opportunities so that consumers who would like to provide input can choose how and to what extent they are involved
- report back on how consumer input has been factored into our planning, processes and forecast expenditure, which will ultimately impact network prices.

2 OUR CUSTOMERS

> *"It's great that you are giving customers information sessions like this session tonight"*

Consumer at Wollongong forum[9]

We based our engagement initiatives on a set of guiding principles that we worked to apply consistently:

Principle	Impact on our engagement activities
Accessible and inclusive	We will identify relevant 'end user' or consumer groups, and recognise that they can change over time. We will engage with end users, and consumer representative groups, retailers and industry bodies where it is in our consumers' best interests. We will identify and work to overcome barriers to customer and stakeholder involvement. This includes providing customers with easy-to-understand information via a variety of different channels to encourage and facilitate their involvement. We will recognise that consumer cohorts are not homogenous and tailor plans and accordingly.
Transparent	Engagement will be open and honest. Customers and stakeholders will be clear about the options that are available to them to provide feedback and how we will consider their input in our planning and decision-making processes.
Clear, accurate and timely communication	We will engage with customers and stakeholders in a way that is clear, accurate and relevant and that allows sufficient time for meaningful conversations, consultation and appropriate modifications to our plans and actions. Engagement will be robust, cost-effective and relevant. We will use methods of engagement that best suit the audience and the goals of engagement. For engagement to be effective, consumers must also commit to the process.
Measurable	We will measure the success of our engagement activities so that we know where and how to improve engagement in the future.
Collaboration	We will look for opportunities to facilitate collaboration with stakeholder organisations. We will also work collaboratively across NSW electricity distributors to share knowledge and create cost savings where possible.
Integrity	We will act honestly and ethically in everything we do and be accountable for our actions. Our engagement will be impartial.

[9] Attachment 2.06: Consumer engagement report, April 2014

2 OUR CUSTOMERS

Our customer research

We have made significant improvement in our engagement with customers through a range of channels and initiatives. We have sought to incorporate the feedback we received in our expenditure forecasts and embed these engagement activities in our business practices.

While we have always engaged with our customers, we significantly increased our engagement program to ensure our priorities and plans reflected their needs. Refer to our supporting attachments for further detail, this comprehensive program included:

- Conducting quantitative and qualitative research with more than 900 residential and 300 small to medium business customers via telephone surveys and focus groups.
- Extending the reach of our engagement program through an innovative Facebook campaign designed in conjunction with Ausgrid and Essential Energy and featuring online polls and infographics.
- Analysing two years of existing customer research including our complaints and compliments data, our quarterly customer satisfaction reports, our energy efficiency product trials and media and Energy Ombudsman (EWON) reports.
- Holding two interactive workshops in Penrith and Wollongong attended by 99 residential and small business consumers on priority customer issues.
- Meeting with a small group of peak consumer representatives at a joint Networks NSW forum to identify issues of concern and begin a discussion on the need to reform electricity tariffs.
- Presenting plans to contain our share of total street lighting costs to no more than CPI for the next five years with representatives of the three Regional Organisations of Councils and in visits to 18 local councils. This was in addition to our regular six monthly visits to monitor their satisfaction with our street lighting service.
- Writing to retailers, industry associations, chambers of commerce, local government, Members of Parliament and other community stakeholders seeking feedback on our electricity plans and prices.
- Promoting our plans to contain our share of bill increases through metropolitan and regional media and inviting feedback from customers and stakeholders.
- Informing Endeavour Energy's Customer Consultative Committee about the key themes and priorities emerging from our engagement sessions and seeking their feedback on our plans.
- Meeting with the AER's Consumer Challenge Panel to respond to questions about our proposed plans.
- Liaising with retailers on our five year plans and proposals for tariff reform via a Networks NSW forum.
- Developing an easy to read summary of our full regulatory proposal, outlining the benefits and risks for consumers.
- Sharing our plans and presentations via our website in the interests of broader transparency.

Beyond this, we plan further engagement initiatives over coming months to listen to customer and stakeholder feedback. Longer term, we plan to embed consumer engagement in our day-to-day business operations.

"It was no small thing to see the thought and effort invested by very senior people in the forum….. the fact they took the time to come along was very encouraging and the participants really appreciated it. I thought it was very valuable…. While networks might stumble with engagement approaches in the early stages, just to have made this effort is recognition of the preparedness of the industry to listen and to value customers.

Now we need to build on this good start. If customers are better included and considered in network business decisions, we can build a network that's best for everyone."

Oliver Derum – Senior Policy Officer, Energy + Water Consumers' Advocacy Program, Public Interest Advocacy Centre and Endeavour Energy Customer Consultative Committee representative

2 OUR CUSTOMERS

Topics we explored with customers and stakeholders

1. **Industry awareness:** general understanding of the structure of the industry, brand awareness, familiarity with network vs. retail operations and general satisfaction with Endeavour Energy.
2. **Pricing and affordability:** perceptions around pricing and recent increases; and the way this affected consumer behaviour, including electricity use.
3. **Reliability:** customers' perceptions and experiences of electricity supply interruptions; and the relationship between reliability and price, and customers' willingness to pay more to increase reliability.

> *"Endeavour Energy is actively trying to help the consumer. They aren't just a business seeking more money"*
>
> *Consumer at Wollongong forum*[10]

4. **Safety:** knowledge and effectiveness of safety education and awareness programs and willingness to pay more or less.
5. **Construction/design standards:** connection costs; the role of aesthetics including overground/underground options; and perceptions about environmental and safety considerations and options.
6. **Street lighting:** satisfaction with street lighting maintenance, new technologies and changes to pricing structures.
7. **Metering technology:** attitudes towards advanced metering and the perceived value of its various features; and willingness to pay for this technology.
8. **Demand management/energy efficiency:** customers' views about a range of demand management and energy efficiency initiatives; solar power, energy savings programs and willingness to pay for these programs.
9. **Support for vulnerable households:** views about who should receive what support; who was best placed to provide it, and the willingness to pay to make sure this support is available. Importantly, we also initiated conversations about future tariff strategies.
10. **Communication and engagement:** exploration of needs and wants in relation to information provided by Endeavour Energy.

We canvassed opinions from a range of our customers and stakeholders – from students to full-time employees to retirees; single-person households to families; tenants and owner-occupiers; business and industry and local government agencies. We also asked low-income and vulnerable customer advocates to give us input.

Customer priorities

Our customer research[11] showed that the three main service aspects prioritised by customers were the same for both residents and businesses:

- Affordability
- Reliability
- Safety

[10] Attachment 2.06: Consumer engagement report, April 2014

[11] Attachment 2.02: Customer engagement study qualitative and quantitative full report, August 2013

2 OUR CUSTOMERS

Cost was clearly seen as the most important priority. These prioirities strongly align with Endeavour's commitment, investment and operating plans for 2014-19 and this is reflected throughout this proposal. Local councils prioritised affordability, maintenance and new lighting technologies as their top priorities.

> *"I expect safety to be a big priority for such an essential service…the minimum standards must be safe"*

Endeavour Energy customer[12]

What the research showed

1. **Industry awareness:** Many people mistakenly thought Endeavour Energy was a retailer and not an electricity distributor. While brand awareness was reasonably high, knowledge of our role and services was poorly understood. Most customers thought we were privately-owned, rather than a State Government entity. This meant some customers thought, incorrectly, that price increases over the past five years were more about profit than funding essential infrastructure and maintenance programs. Many suggested the need for a broad awareness and education program.
Source: Customer research, deliberative planning forums, stakeholder comment.

2. **Pricing and affordability:** Customers nominated affordable electricity as their top priority. They welcomed news that Endeavour Energy was working hard to end network price rises and pass on savings to customers. Many were confused about the reason for past increases. Most had modified behaviour and usage in an attempt to reduce their bills. There was an overwhelming preference for steady, stable prices. Some were concerned about the sustainability of cost reductions and the possible risk this presented to reliability and security of supply.
Source: Customer research, stakeholder forums, deliberative planning forums, media comment, customer complaints, Facebook.

3. **Reliability and outages:** Reliability ranked as the second highest customer priority. Businesses particularly, and most residents were happy with the level of reliability they receive from Endeavour Energy and so were not particularly willing to pay more for a more reliable service – 75% of domestic customers and 92% of businesses felt this way. Nor were they willing to accept a less reliable service in exchange for a lower bill. Most people understood that when the power was unexpectedly interrupted, Endeavour Energy did its best to get the power back on as quickly as possible. Unplanned outages directly affect customer satisfaction. Customers expected Endeavour Energy to make better use of technology to tell them when the power will be back on. A minority wanted to know the cause of the outage. For planned outages, customers wanted better information ahead of an outage.
Source: Customer research, deliberative planning forums, stakeholder forums, media comment, customer correspondence, Facebook.

4. **Safety:** While safety ranked as the third highest priority for customers, high standards of safety were considered a given for a modern electricity network. Customers believed safety should be factored into our designs and into our maintenance plans. There was little support to pay more for greater safety, or less for lesser safety standards.
Source: Customer research and deliberative planning forums.

5. **Construction and design standards and vegetation management:** Customers were surprised to learn that undergrounding power lines costs four to 10 times more than an overhead network, even though many preferred its appearance. Only a quarter of surveyed customers were willing to pay more to replace overhead lines with underground cabling. Most accepted the need to trim trees but supported a more sympathetic approach to tree trimming and improved education programs.
Source: Customer research, deliberative planning forums, analysis of council and customer correspondence.

[12] Attachment 2.02: Customer engagement qualitative and quantitative full report, August 2013

6. **Street lighting:** Councils welcomed Endeavour Energy's regular communication sessions and were generally satisfied with improved maintenance standards. They welcomed our plan to keep our share of total street lighting costs to no more than CPI for the next five years. Many expressed interests in new lighting technologies.
Source: Stakeholder meetings, Council forums and correspondence.

7. **Metering technology:** Customers were less willing to pay more for technology such as smart meters, some were distrustful of the technology, but valued information on how they might better manage their energy usage from Endeavour Energy.
Source: Customer research, deliberative planning forums, Facebook.

8. **Demand management and energy efficiency:** Customers' top priority was to minimise bills, but only to the extent that comfort and lifestyle were not compromised. They also wanted to retain control of their energy usage, their meter and the way in which they are charged for energy usage. Customers expected a substantial incentive to participate in Endeavour Energy initiated energy efficiency programs. Others encouraged us to pursue renewable energy initiatives given the rapid uptake of solar.
Source: Customer research, Facebook, deliberative planning forums, energy efficiency trials.

9. **Support for vulnerable households:** Customers and stakeholders agreed that vulnerable customers deserved dedicated support and welcomed Endeavour Energy's attempts to make electricity more affordable. Customers also supported a special tariff for vulnerable customers. They indicated that the company which sends customers the bill is the one best placed to support vulnerable households.
Source: Consumer research, Facebook, Customer Consultative Committee and Stakeholder forums.

10. **Communication and engagement:** Most liked Endeavour Energy's approach to community consultation for major projects; valued easy to access information about how and where they could minimise their electricity bill and encouraged Endeavour Energy to make greater use of technology, including smart phone apps, to deliver efficient improved service. Customers preferred timely communication about network incidents and outages via channels that suited them.
Source: Customer research, deliberative planning forums, Facebook, customer comments.

Consumer Challenge Panel

In addition to our own engagement activities we also interacted with the Consumer Challenge Panel (CCP) in preparing and explaining our plans. The AER established the CCP to help it make better regulatory determinations by providing inputs on issues of importance to customers. Endeavour Energy has met with the CCP to discuss and respond to questions about our transitional regulatory proposal. This process has provided us with insights into issues of concern to the CCP:

- the need to engage with local councils on street lighting
- Endeavour Energy's proposed capital expenditure
- the operation of the efficiency benefits sharing scheme (EBSS) and how this scheme impacts on customers in terms of prices.

We have sought to address these matters raised by the CCP in this regulatory proposal with the exception of the EBSS as this is an AER incentive scheme which provides long term benefits for customers that we have applied as required by the NER.[13]

[13] Clause 6.4.3(a)(5)

2 OUR CUSTOMERS

Our response to customers

We have carefully considered the feedback we have received from customers so far. In developing this proposal we have sought to address their concerns and priorities.

What we can do as a result of the engagement

We've gathered an extensive amount of feedback from our customer engagement activities to date. Here's a snapshot of priority issues explored and what we're doing about them.

You said…	A snapshot of what we'll do
Pricing *"Anything Endeavour can do to keep costs down is welcome"* Customers want stable, affordable electricity with no steep increases.	Continue our productivity and efficiency programs which delivered a real decrease in network electricity charges for the first time in a decade in July 2013. Keep increases in our share of electricity bills to at or below CPI for the next five years.
Reliability and outages *"We're living in a first world country and paying for a service"* Most customers rate Endeavour Energy's level of reliability as very good and don't want to pay more for a better service. Nor are they prepared to pay less for poorer reliability. Customers also asked us to improve how we notify them about outages and improve content too.	Maintain our current level of reliability. Introduce a new mobile site to give customers live outage information. Investigate improved notifications using SMS and smart phone apps and review our written interruption notices.
Safety *"I expect safety to be a big priority for such an essential service…the minimum standards must be safe"* Customers don't want safety and reliability standards to be compromised, even for lower prices.	Improve our safety programs for our staff and contractors. Maintain our road side power pole 'black spot' relocation program; continue our public safety education program; and expand its reach via social media.
Energy efficiency and demand management *"I've already done a lot to reduce my energy bill and welcome information and tools to help manage my electricity use"* Customers appreciate advice on how to keep costs low but were generally unwilling to compromise their lifestyle.	Provide low cost, accessible tools on our new website. Promote our demand management programs for large customers. Maintain our efficiency programs to help keep increases in our share of customers' bill to at or below CPI.
Supporting vulnerable customers *" ..it's important, yes, but my priority is containing my bill"* Customers recognised the need to keep electricity affordable for the most vulnerable but did not think it was Endeavour Energy's role.	Continue our conversation with consumer groups to rethink the way we charge, so that those who can't afford it are not paying for those who can. Review our services for vulnerable customers, particularly life support customers.

2 OUR CUSTOMERS

You said…	A snapshot of what we'll do
Customer satisfaction and service "*Why can't you keep the lights on…I'm paying a lot for this service*" Customer satisfaction is strongly linked to satisfaction with reliability. The more frequent the outages, the lower the satisfaction. Many customers expect us to also make good use of customer friendly apps and drive improvements to customer service.	Renew our focus on customer service and develop new customer service apps for street lighting and graffiti reporting. Design a new, customer focused website and mobile site.
Construction designs and standards "*I want substations to look good if they are in my neighbourhood and for them to be secure*" Customers want attractive streetscapes, well designed infrastructure, tidy streets and construction sites. Failure to do this reduces satisfaction.	Keep designing substations to blend in with residential streets but spend less on design in industrial areas to save money. Remind our staff and contractors to leave streets, construction and work sites tidy.
Vegetation management *"I understand you need to trim trees for safety but I don't always like the result"* Customers asked that we educate councils and residents about more appropriate plantings.	Continue to reduce safety hazards by trimming trees. We'll work with councils to promote planting of appropriate species in overhead areas and we'll leave work sites tidy.
Metering technology *"I want tools to keep costs down but I don't want my old meter replaced with a smart meter"* Customers want to know how to reduce their bill, but they want to retain control and not compromise lifestyles.	Keep accumulation meters as our standard meter as they're the cheapest. We'll also give customers the choice to pay for smart meters if they'd like extra functionality.
Communication, education and engagement "*I don't know a lot about Endeavour Energy and its programs – you need to do more to educate your customers*" Awareness of Endeavour Energy was very low before the engagement sessions. Many thought we are privately owned and that was why prices had increased. Customers also suggested more communication programs to educate customers.	Expand the reach of our information and education programs through better use of social media, targeted communication to affected stakeholders and by leveraging our relationship with other stakeholders. Review the success of our engagement program and work to embed engagement processes in our day to day business.

What we cannot do as a result of the engagement

Endeavour Energy is also required to outline what it will not do as a result of the engaging with customers and stakeholders even though a preference may have been expressed for a particular approach during consultation sessions. Here are some of things we cannot do, largely since they add substantial costs which would have to be passed onto customers.

- Prices: we will not return to a period of steep increases in our share of customers' bill.
- Reliability: we will not provide additional funding for network projects to improve reliability above acceptable standards.
- Safety: we will not compromise safety standards or reduce safety programs.

- Vegetation management: we will not amend tree trimming practices if they compromise safety or increase costs.
- Construction and design: we will not underground existing areas of overhead network without sufficient justification and a source of payment from those who derive benefit.
- Metering: we will not adopt smart meter technology as our default meter unless it is mandated by law.

What we have learned from engagement

Endeavour Energy plans to evaluate the effectiveness of its consumer engagement approach and report this on an annual basis in the interests of transparency.

We will use this assessment to drive improvements and embed best practice consumer engagement in our day to day decision making, planning and operations.

Over time, Endeavour Energy is confident that these activities will better align our plans with consumers long term interests and deliver a safe, affordable and sustainable electricity service for all.

The benefits and risk to consumers about this proposal

Our proposal provides the following benefits and risks to our customers:

Benefits to our customers

- Stable prices - We propose to keep average price increases to our share of customers' electricity bills to at or below CPI for the next five years
- Reliability - We propose to maintain reliability.
- Safety - Our capital and operating plans aim to deliver programs that are safe and sustainable for the electricity network and the communities it serves.
- Clarity of costs - We are giving customers greater transparency about how much they pay for metering.
- New growth areas - Electricity infrastructure for new growth centres will foster economic development of these areas.
- Removing cross subsidies - Customers who don't use specific services (such as special meter test readings) will no longer subsidise those who do.

Potential risks to customers

- Volatility - The AER has determined that Endeavour Energy's revenue will be capped. If electricity consumption falls further than we forecast, unit prices might increase but total revenue cannot increase.
- Reduced reliability - If our capital program is not delivered on time the electricity supply less may be less reliable in some areas.
- New Rules - Customers who request a special service such as meter test may now pay considerably more for that service as the AER said they cannot continue to be subsidised by our general customer base.
- Future prices - Without changes to tariff structures customers who cannot afford to invest in solar technology will be burdened with increased network costs.

3 SERVICES AND PRICE CONTROLS

Summary

The AER has already made a number of decisions affecting our regulatory determination as part of the framework and approach process. Our regulatory proposal sets out where we agree with the AER's decision or approach, and where we propose an alternative.

The framework and approach (F&A) paper sets out the key decisions the AER has made prior to our submission of this regulatory proposal. The AER is required to publish the paper in two stages. The key points in this chapter are:

- Our proposal adopts the AER's decisions in the F&A paper. This includes the AER's decisions on classification and control mechanisms, subject to seeking minor clarifications on definitions.
- We are however suggesting minor amendments and clarifications to the way incentive schemes should be applied as part of the building block determination.

We have set out our proposals in response to Stage 1 and 2 of the AER's F&A paper below.

Our proposals in response to Stage 1 of framework and approach

In this section, we set out the decisions the AER made in Stage 1 of the F&A paper. The paper was published on 25 March 2013 and sets out the AER's decisions on classification of services, control mechanisms, and pricing of dual function assets.

Proposal on classification of services

Classification of distribution services is important as it determines the extent of regulation to apply to our services. In Stage 1 of the F&A paper, the AER largely adopted the previous classification of services that applied to our 2009-14 determination. The key changes were:

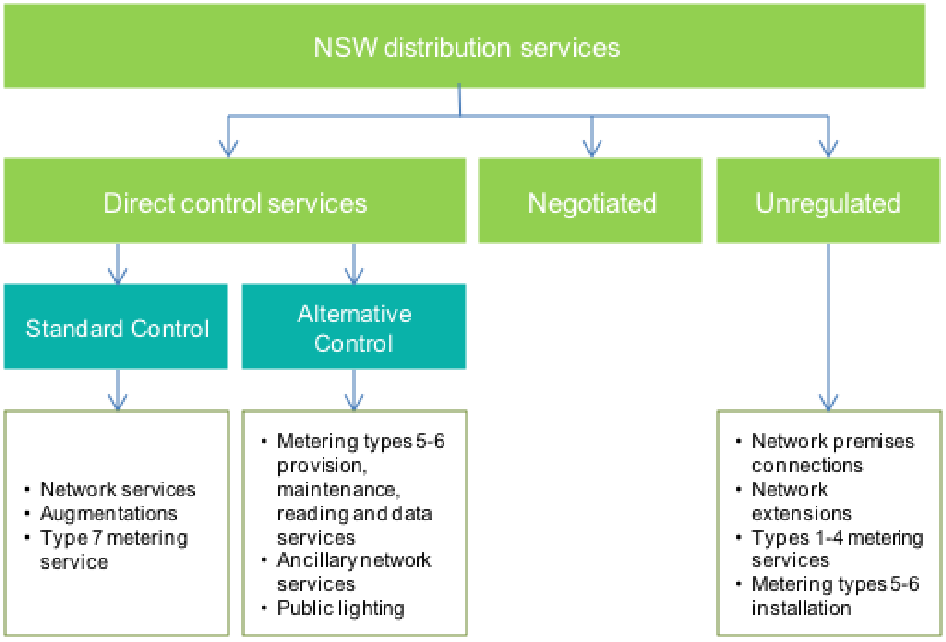
- type 5 and 6 metering services and ancillary services were re-classified from standard control to alternative control services (ACS)
- emergency recoverable works were re-classified from standard control to unclassified services
- the AER provided more definitions on the types of services that a distribution network service provider (DNSP) provides such as connections and augmentations, and showed how these related to its decision on classification of services.

The Rules require that our proposal shows how the distribution services we provide should, in our opinion, be classified for the next regulatory period. If our proposed classification differs from the classification suggested in the F&A paper, we are required to identify our reasons for the difference.

Our proposal is to adopt the AER's classification of services decision in Stage 1 of the F&A paper. This is set out in the following diagram.

3 SERVICES AND PRICE CONTROLS

Figure 8: Framework and approach stage 1 outcomes for classification of services



While we propose no change to the AER's decision, we note that there are two areas where we consider the AER's determination could provide more clarity on service definitions as part of its regulatory determination.

- Definition of network augmentations. Categorising network augmentations under the broader service grouping of 'connections' is problematic. Augmentations of the network may be driven by new customers connecting to our network, but can also be driven by the need to reinforce the network as a result of increasing demand from existing users[14], improving security of the network particularly in response to new licence security criteria, and to address voltage issues. We request that the AER's draft determination makes clear that augmentations may also relate to these issues.
- Negotiated services. We agree with the AER that none of the services provided by Endeavour Energy are suited to being classified as negotiated distribution services. If Endeavour Energy is required to provide negotiated distribution services it will apply its negotiating framework. This is further discussed in Chapter 9 where we identify the pricing and reporting arrangements.

Dual function assets

Endeavour Energy has a small number of sub-transmission lines and cables and transformers which could be potentially classified as dual function assets providing standard control services. These assets form transmission exit assets supporting Endeavour Energy's distribution network.

The value of these assets are immaterial and are within Endeavour Energy's existing distribution use of system (DUOS) pricing arrangements. The AER has acknowledged that changing the pricing approach to transmission pricing would not have a material impact on distribution prices and would incur administrative costs. Accordingly, the AER has determined that the distribution pricing will continue to apply for Endeavour Energy.[15]

[14] Or combined growth related to both existing and new users.

[15] AER, Stage 1 Framework and Approach paper, p 11

3 SERVICES AND PRICE CONTROLS

Control mechanism

Control mechanisms provide the basis of how the AER is to regulate standard control and alternative control services. In Stage 1 of the F&A paper, the AER decided that:

- The basis of control for standard control services was to be a CPI-X form consistent with the Rules, and the form of control was to be a revenue cap. The AER also set out its proposed approach to the formulae that give effect to the control.[16]
- It would confirm a basis of control for alternative control services in making its determination, and that the form of control would be caps on the prices of individual services. The AER also set out its proposed approach to the formulae that give effect to the control.[17]

We are not able to propose a change to the form of the control mechanisms, as the Rules require that they must be as set out in the relevant framework and approach paper. The AER is able to amend its formulae that give effect to the control mechanisms only if the AER considers that unforeseen circumstances justify departing from the formulae. We do not propose any changes to the formulae, and therefore we have adopted the AER's decision on classification of services.

Our proposals in response to Stage 2 of framework and approach

In this section, we set out the decisions the AER made in Stage 2 of the F&A paper.

The F&A Stage 2 paper was published on 31 January 2014 and sets out the AER's decisions on application of incentive schemes, depreciation to be applied when rolling forward the Regulatory Asset Base (RAB), and guidance on approach for true-up of alternative control services.

In addition, the AER has stipulated that its approach is to apply the Forecast Expenditure Assessment guideline, including the information requirements, to the NSW distributors in the subsequent regulatory control period. We have demonstrated compliance with this requirement as set out in our compliance checklist.

Incentives and guidelines to apply to standard control services

Incentives form part of a building block determination, but the AER is required to set out its proposed approach in advance as part of the F&A process. In the sections below we identify whether we propose to apply the AER's approach as set out in the F&A paper.

Efficiency Benefits Sharing Scheme

The EBSS provides a continuous incentive for the DNSP to achieve efficiency gains in its operating expenditure. The EBSS that applied to Endeavour Energy for the current 2009-14 period was recently revised by the AER (November 2013 version or version 2).[18]

[16] The AER clarified in the Stage 2 of its framework and approach paper that separate revenue caps will apply (with different X factors) for the transmission and distribution portions of revenue for standard control services.

[17] The AER clarified in Stage 2 of its framework and approach paper that it will derive the prices of quoted services from their relevant input costs (e.g. labour rate, material cost).

[18] AER, Better Regulation, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013.

For the transitional year, the AER has decided that the EBSS applicable to the current 2009-14 period, as modified to align to version 2 of the EBSS (the modified EBSS), will apply as if the transitional year was the first year of the subsequent regulatory control period.[19] For the 2015-19 regulatory period, the AER specified that version 2 of the EBSS will apply Endeavour Energy.[20]

As explained further in Chapter 6, in developing the forecast opex for the 2014-19 period, Endeavour Energy has used the adjusted actual opex outcome for the 2012-13 year as the starting opex base. The adjustment relates to the actuarial assessment of long service leave obligations. This adjustment is necessary to ensure that the base opex, upon which cost escalation and change factors are applied, represents the underlying ongoing opex needed to provide standard control services.

We note that clause 6.5.8(a) of the Rules states that the efficiency gains/losses are calculated as the difference between actual opex being less/more than the forecast opex accepted or substituted by the AER. The incremental efficiency gain or loss is then calculated by reference to the efficiency gain/loss of the current year and the prior year.

Consequently, to ensure comparability between the actual outturn opex and the forecast opex and to ensure that the efficiency gain/loss (and therefore the incremental efficiency gain/loss) are accurately calculated, Endeavour Energy considers that, in applying the modified EBSS and the version 2 EBSS for the transitional regulatory control period and the 2015-19 regulatory control period, actual outturn opex should also be adjusted for actual outturn actuarial assessment for employee related entitlement provisions. In this way, the performance of the DNSP against the efficient opex benchmark accepted or substituted by the AER is not distorted.

Capital Expenditure Incentive Sharing Scheme and proposed approach to depreciation

The Capital Expenditure Incentive Sharing Scheme (CESS) was recently introduced into the regulatory framework resulting from the AEMC's Rule change. The CESS provides reward/penalty for efficiency gain/loss with respect to capital expenditure. The AER published its capital expenditure incentive guideline in November 2013 which sets out the CESS.[21]

In its distribution determination for the transitional year (i.e. 2014-15), the AER specified that no CESS applies.[22] This is consistent with the requirement of the Transitional Rules.[23]

The AER proposes to apply its CESS in the 2015-19 regulatory control period in accordance with its published guidelines. Endeavour Energy's proposal is to apply the CESS in the 2015-19 regulatory period; consistently with the AER's proposed approach to its application to Endeavour Energy as stated in the AER's Stage 2 F&A.

Another key element of the overall capital expenditure incentive framework is the depreciation approach to use when a distributor's RAB is updated from forecast capex to actual capex at the end of a regulatory period. In establishing the value of the RAB as at the beginning of the period subsequent to the 2015-19 period, i.e. as at 1 July 2019, the AER can decide either to use the depreciation on actual capex (actual depreciation) or the depreciation on forecast capex (forecast depreciation). The choice of depreciation affects the power of the incentives that apply to capital expenditure.

The AER has proposed to use the forecast depreciation approach to establish the RAB at the commencement of the 2019–24 regulatory control period for NSW distributors. The AER considers that this approach, in combination with the CESS, will provide sufficient incentive for the distributors to achieve capital expenditure

[19] AER, Ausgrid Placeholder determination for the transitional regulatory control period 2014-15, p2.

[20] AER, Stage 2 Framework and Approach paper, p 20.

[21] AER, Better Regulation, Capital Expenditure Incentive Guideline for Electricity Network Service Providers, November 2013.

[22] AER, Ausgrid Placeholder determination for the transitional regulatory control period 2014-15, April 2014, p3

[23] Clause 11.56.3(a)(3) of the Rules.

efficiency gains over the 2014-19 period. Our proposal is to apply the AER's approach as set out in the AER's F&A paper.

Service Target Performance Incentive Scheme (STPIS)

The AER proposed to not apply its national STPIS to the NSW distributors in the transitional period. It noted that under its approach the current performance reporting obligations will continue to apply with no revenue at risk. Our proposal is to accept the AER's approach not to apply the STPIS to the transitional period.

The AER has proposed that the scheme will apply from 2015-16 and onwards and has identified its proposed arrangements. Amongst other things, the AER proposed to set the revenue at risk to be within the range of +/-5%. The AER stated:

> *In their response to the AER's 2012 Preliminary Framework and Approach, the NSW distributors considered the ±5 per cent revenue at risk (as indicated in the national STPIS) to be excessive considering the ongoing uncertainty in the NSW electricity environment. The NSW distributors instead suggested applying a revenue at risk of ±2.5 per cent. Consistent with the objectives of the STPIS, we propose to set revenue at risk reflective of the particular circumstances of each distributor and within the range of ±5 per cent. We will determine the revenue at risk during the distribution process following receipt of the NSW distributors' regulatory proposals and submissions on those proposals.*[24]

With respect to the application of the STPIS, Endeavour Energy proposes a revenue at risk of ±2.5%. We note that this is within the range specified by the AER as noted above. Our proposed revenue at risk is consistent with previous representations we have made to the AER.[25] At that time, we noted that applying the maximum revenue at risk of ±5% available under the scheme would be excessive given the implementation issues with transitioning to a new scheme.

We consider our proposed revenue at risk best meets the objectives of the scheme identified in section 1.5 of the STPIS, in particular the willingness of the customer or end user to pay for improved performance in the delivery of services as stipulated in 1.5(b)(6) of the scheme. Endeavour Energy's customer research has shown that the majority of customers are satisfied with their existing level of reliability suggesting a reluctance to pay any more for improvements.

Our complete proposal on how the STPIS will apply is set out in Attachment 0.14. This includes additional information including our assumptions, proposed targets and incentive rates. The key elements of our proposal are:

- In terms of reliability parameters, we propose a revenue at risk of ±2.25% Our proposal is to apply the SAIDI and SAIFI parameters which relate to duration and frequency of outages We consider that measures of momentary outages should not apply due to data quality issues.
- For customer service parameters, we consider that only telephone response times should be included in the scheme. We propose a revenue at risk of ±0.25%. Endeavour Energy also proposes that when an event is excluded from the calculation of reliability performance, the event should also be consistently excluded from the calculation of our telephone service performance
- We suggest the AER adjust its approach to setting targets for customer service. A five year historical average is proposed by the AER. This should be adjusted to account for the retail sale and the conclusion of the transitional services. An averaging period post retail separation would better reflect our operating model and ensure we do not need to increase our expenditure to support inflated targets.

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[24] AER, Stage 2 Framework and approach: Ausgrid, Endeavour Energy and Essential Energy, January 2014, p16
[25] NSW distributors, *Response to AER Preliminary F&A*, Aug 2012, p65

- We suggest that the definition of major event days (MED) and segmentation definitions be varied for Endeavour Energy. Our data supports a move from the 2.5 Beta methodology as the normal distribution assumption does not hold for Endeavour Energy.

Our complete proposal on how the STPIS will apply is set out in Attachment 0.14. This includes additional information including our proposed targets and individual weightings.

Demand Management Incentive Scheme (DMIS)

The AER proposed to continue applying Part A of the Demand Management Incentive Allowance (DMIA) at the same scales as currently applied to NSW DNSPs, but to discontinue Part B of the scheme which related to compensation for foregone revenue. Our proposal is to apply the AER's approach given that we are no longer under a weighted average price control cap. The AER's approach is set out in *AER Guideline – Replacement Demand management incentive scheme for ACT and NSW – 28 November 2008.*

This guideline sets out the allowance under Part A of the scheme that Endeavour Energy may access. This allowance is provided as an annual ex ante allowance in the form of a fixed amount of additional revenue at the commencement of each regulatory year. Endeavour Energy will continue to submit an annual report of DMIA expenditure to the AER which will be reviewed and approved provided it meets the criteria specified in the guideline. The guideline also sets out the calculation of the final year adjustment.

The AER also proposed to discontinue the non-compensatory incentive component of the D-Factor scheme for NSW distributors from the transitional regulatory control period onwards. However, as the D-factor operates on a two years lag, Endeavour Energy will be recovering the associated costs of demand management projects in the 2014-19 period. [26]

The AER has noted that the Standing Council on Energy and Resources (SCER) is currently considering a series of rule changes proposed by the AEMC in its Power of Choice review examining distributor incentives to pursue efficient alternatives to network augmentation. This will include new rules and principles guiding the design of a new DMIS. The AER intends to develop and implement a new DMIS for the subsequent regulatory control period, depending on the progress of the rule change process. Our proposal is that the AER should apply the incentive scheme if a Rule change is implemented in time for our final determination, subject to consultation with Endeavour Energy.

Refer to Attachment 5.34 for an overview of our demand management strategy.

Small Scale Incentive Scheme

The Rules allow the AER to develop a Small-Scale Incentive Scheme. Given that the AER has not developed this scheme, our proposal is to apply the AER's approach and not implement such a scheme during the course of the 2014-19 proposal period.

Confidentiality Guideline

Endeavour Energy has sought to have suppressed from publication certain parts of the regulatory proposal on the grounds of confidentiality. This is typically to protect the privacy of our staff, suppliers or customers and to ensure that commercially sensitive information is not published. We have completed a confidentiality template in relation to this information as required by the AER's Confidentiality Guideline. This template is submitted with this regulatory proposal as Attachment 0.19.

[26] Stage 1 Framework and Approach paper, p32.

Expenditure Forecast Assessment Guideline

Clause 6.8.2(c2) requires Endeavour Energy's regulatory proposal to be accompanied by information required by the Expenditure Forecast Assessment Guidelines as set out in the AER's F&A paper. The guideline was published by the AER in November 2013 in which the AER stated that:

> *The regulatory information notice (RIN) issues in advance of a DNSP lodging its regulatory proposal will specify the exact information we require….the following sections indicate (at a high level) our likely information requirements for capex and opex.*[27]

This approach is confirmed by the AER in its Stage 2 F&A in which the AER stated that guideline was developed to apply broadly to all electricity transmission and distribution businesses and some customisation of the data requirements contained in the guideline may be required and that these customisation issues would be addressed through the Regulatory Information Notice (RIN) that the AER issues to the NSW distributors for the 2014-19 period.

Endeavour Energy has undertaken a comparison of the high level requirements contained in the Expenditure Forecast Assessment Guideline against the specific requirements in the RIN. All matters covered by the Guideline are addressed by the RIN requirements which have been customised to reflect Endeavour Energy's business. Accordingly, Endeavour's RIN response, that accompanies this regulatory proposal, meets the requirements of the Guidelines as required by the AER's F&A paper.

True-up for alternative control services

The NSW distributors requested that the AER specify in Stage 2 of the F&A paper how a true-up of prices will be made for alternative control services. We set out their preliminary views on how a true-up mechanism could work in Attachment 8.10.

In the F&A paper the AER noted that, given that it was yet to see how Endeavour Energy intended to treat alternative control services pricing in their transitional proposals, it preferred not to prejudice whether, and if so, how alternative control services prices are to be trued-up. For this reason, it did not specify the exact manner in which alternative control services prices may be adjusted in this F&A paper.

Chapter 8 of this proposal document discusses our proposed approach for the true-up of alternative control services for the transitional year. We also note that Chapter 4 has been clear on our proposed method for the true-up of standard control services.

[27] AER, Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution, November 2013, page 25.

4 BUILDING BLOCK PROPOSAL

Summary

We propose total annual revenue requirements of $5.3 billion ($nominal) for the 2014-19 regulatory control period. This amount is needed to recover the efficient costs we reasonably expect to incur in providing standard control services.

Endeavour Energy provides a range of distribution services that are classified by the AER as standard control services. These are central to the supply of electricity and are relied on by most (if not all) of our customers.

We are required to provide the AER with a 'building block' proposal for standard control services that is used to set a revenue cap for each year of the regulatory control period. The key points of this chapter are:

- We are striving to contain average increases in our share of customers' electricity bills at or below CPI over the next regulatory control period.
- We have sought to minimise our revenue by reducing our costs and improving productivity.
- We have smoothed our revenues for 2014-19 to reduce price volatility. In doing so, we have investigated how forecast volumes will impact the prices customers pay over the period.

Proposed building blocks

This section provides a summary of our proposed building block components. The building blocks refer to the efficient costs that a DNSP reasonably expects to incur in a regulatory period.

We have used the building block approach prescribed in the Rules for the calculation of revenue requirements relating to standard control services.[28] These main elements are inputs into the annual revenue requirement using the AER's post-tax revenue model (PTRM).

In the sections below, we have identified the building block components we have used to calculate the annual revenue requirement for each year of the regulatory control period,[29] consistent with the Rules requirements. The building blocks relate to the following types of costs:

- Return on capital. We receive an allowance for a return on capital. This is to repay our debt and provide a reasonable return on equity for the funds we borrow or raise through debt and equity to fund investments. The calculation of the return on capital is based on key inputs including the value of the opening asset base, the allowed rate of return and forecast capital expenditure.
- Return of capital. We receive an allowance for a return of capital (depreciation). The calculation of the return of capital is based on key inputs such as the value of the opening asset base and the remaining lives of assets and is calculated on a straight-line basis. The AER offsets changes in

[28] As noted in section 4.2.2, our proposed building blocks and annual revenue requirement for each year of the 2009-14 period relate to standard control services only. That is, our proposal does not include amounts relating to alternative control services or unclassified services.

[29] We note that while this proposal relates to the subsequent regulatory control period, the Rules require us to treat the 2014-15 transitional year as if it were the first year of the period. See clause 11.56.4.

indexation of the RAB through its depreciation calculation and refers to this as 'regulatory depreciation'.

- Operating and tax costs. We receive a revenue allowance to fund our operating activities and to meet our income tax liabilities.
- Other revenue increments or decrements. We receive a revenue increase or decrease based on outstanding penalties or rewards from incentive schemes that applied in the 2009-14 period. The Rules also enable a revenue decrement arising from the use of assets that provide standard control services to provide certain other services.

The building block components of our proposed indicative annual revenue requirements (unsmoothed) for 2014-15 to 2018-19 are outlined in Table 4.

Table 4: Nominal building block components for 2014-19

$m; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Return on capital	494.0	528.4	555.8	578.8	603.3	**2,760.3**
Return of capital	62.6	72.3	83.1	88.1	93.3	**399.6**
Operating expenditure	273.6	285.6	302.2	307.0	321.1	**1,489.5**
Cost of corporate tax	59.9	62.7	69.2	70.1	71.9	**333.8**
EBSS adjustment	97.5	33.3	42.3	34.2	0.0	**207.3**
DMIS revenue	0.6	0.6	0.6	0.7	0.7	**3.2**
Shared asset revenue	62.1	0.0	0.0	0.0	0.0	**62.1**
Total indicative revenue (unsmoothed)	**1,050.3**	**982.9**	**1,053.2**	**1,078.9**	**1,090.4**	**5,255.7**

Return on and of capital

We receive a return on the value of the RAB, determined by multiplying the value of the opening RAB by the allowed rate of return. The value of the RAB throughout the regulatory period reflects the remaining value of past capital investments and the forecast value of future capital expenditure. The proposed rate of return reflects the cost of capital for a benchmark efficient network service provider.

We receive a return of capital or regulatory depreciation based on the age profile of the assets within the regulatory asset base and the method of calculating depreciation.

The key inputs to developing our estimate of return on and return of capital is identified below.

Indicative estimate of value of regulatory asset base

The indicative value of the RAB as at 1 July 2014 is $5,593 million in nominal terms. This RAB value has been calculated based on clause 6.5.1 and schedule 6.2 of the NER (despite schedule 6.2.1 being not applicable to the transitional year) and the AER's roll forward model (RFM). The completed indicative RFM is provided at Attachment 4.01.

4 BUILDING BLOCK PROPOSAL

As the AER has changed the classification of type 5-6 metering services and ancillary network services to alternative control services from 1 July 2014, adjustments to the value of the RAB as at 1 July 2014 were necessary to exclude the values of assets used to provide type 5-6 metering services and ancillary network services. (See Chapter 8 for a discussion of type 5-6 metering services.)

As a result, an amount of $22.7 million has been excluded from the RAB as at 1 July 2014 to reflect the values of existing assets used to provide type 5-6 metering services. Provision of ancillary network services does not require the use of capital assets and therefore, no adjustment has been made to the RAB value for ancillary network services.

Table 5 below shows the roll forward of our RAB from 1 July 2009 to 30 June 2014:

Table 5: Indicative opening RAB value for standard control services as at 1 July 2014

$m; Nominal	2009-10	2010-11	2011-12	2012-13	2013-14
Opening RAB	3,690.0	3,940.4	4,340.2	4,908.0	5,343.9
Add: actual and estimated capital expenditure	423.2	507.3	647.3	581.7	564.1
Less: regulatory depreciation	(172.8)	(107.6)	(79.5)	(145.7)	(98.9)
Less: adjustment to reflect actual vs allowed capital expenditure in 2008-09					(193.4)
Less: indicative metering services assets removed					(22.7)
Indicative opening RAB value as at 1 July 2014					**5,593.0**

Forecast capital expenditure

The forecast capital expenditure relating to the provision of standard control services is shown in Table 6 below:

Table 6: Indicative expenditure plans relating to the provision of standard control services

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Capital expenditure (SCS - excludes ACS)	432.9	361.1	314.3	325.7	312.0	**1,746.1**

The forecast expenditure profile highlights a reduction in capital expenditure requirements from the 2009-14 regulatory control period, reflecting our continuing commitment to be prudent and efficient with investments and operations. Details of our expenditure plan are provided in Chapter 5 of this proposal.

Allowed rate of return

We propose a rate of return of 8.83% using a trailing average approach to the cost of debt and a long-term average approach to the cost of equity informed by the range of relevant available evidence on the efficient cost of equity for energy networks.[30]

We propose a cost of debt of 7.98%, a cost of equity of 10.11% and a gearing level of 60%. Table 7 shows the Weighted Average Cost of Capital (WACC) parameters we used to calculate the revenue requirements. Chapter 7 of this proposal provides further information on the proposed rate of return.

Table 7: Forecast WACC range

Rate of return parameters	Proposed WACC %	Reasonable range of estimates - %
Overall WACC	**8.83%**	**8.83% - 9.44%**
Cost of equity	10.11%	10.11% - 12.31%
Cost of debt	7.98%	7.98% - 8.06%
Gearing	60%	60%
Utilisation of imputation	25%	25%

Regulatory depreciation

Regulatory depreciation is the depreciation on the value of the regulatory asset base offset by the indexation on that asset base.The depreciation amount for each year of the 2014-19 period is shown in Table 4.

We have calculated the depreciation on the RAB using the straight line depreciation method which divides the opening asset values as at 30 June 2014 by the remaining lives and new assets (i.e. forecast capex for the 2014-19 period) by the standard lives.

We have adopted the AER's preferred approach to the calculation of remaining lives of assets as at 1 July 2014. This approach calculates the remaining lives as at 1 July 2014 by weighting the remaining lives of assets existing as at 1 July 2009 and the remaining lives of assets that are rolled into the RAB during the 2009-14 period (i.e. capital expenditure of this period). The weighting used is the depreciated regulatory value. Whilst we have adopted this approach, we note that it over-estimates the remaining lives as new assets are given more weighting.

We are investigating this issue further, but from preliminary analysis, the AER's preferred approach to calculating remaining asset lives significantly over-weights new assets and therefore over-estimates the remaining life of assets on our network. This is currently resulting in under-compensation for depreciation expense. One indicator of remaining asset lives is that used for accounting purposes. For depreciable assets as at 1 July 2014 Endeavour Energy has a weighted average remaining life of 30.4 years according to the AER's approach, but an actual weighted average remaining life for accounting purposes of 33.5 years.

[30] We refer to the return on equity and the return on debt in the NER as the cost of equity and the cost of debt.

This higher estimated remaining life for regulatory purposes under-estimates actual depreciation expenses that are likely to be incurred by Endeavour Energy over the 2014-19 period

Within the AER's PTRM, depreciation is calculated as straight line depreciation less the indexation of the RAB for inflation.[31] We have used a forecast inflation of 2.5% as a placeholder for this proposal and we propose that this forecast be updated using the AER's approach to calculating forecast inflation. This approach uses a geometric average of the RBA's forecast of inflation for the first two years and the mid-point of the RBA's target range for inflation (2.5%) for another 8 years to provide a 10 year forecast of inflation. We note that the AER will update this forecast for the latest RBA inflation estimates at the time of its final decision.

Indexing the RAB for inflation increases its nominal value over time and allows a return on capital to be earned on the indexed component. However, reducing depreciation allowances by the amount of indexation means that depreciation allowances are not sufficient to compensate DNSPs for actual depreciation expenses in the short to medium term. The regulatory approach to depreciation combined with the over-estimation of remaining asset lives for regulatory purposes is currently resulting in under-compensation for Endeavour Energy's depreciation expenses. We will be conducting further analysis on this issue and will provide any findings to the AER as they become available.

Operating and tax costs

Forecast operating expenditure

The forecast operating expenditure relating to the provision of standard control services is shown in Table 8 in 2013-14 dollar terms. Details of our expenditure plan are provided in Chapter 6 of this proposal.

Table 8: Indicative opex relating to the provision of standard control services

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Opex (inc DMIS and DRC)	267.6	272.4	281.2	278.7	284.4	**1,384.3**

Estimated cost of corporate tax

To estimate the cost of corporate income tax we have used the current corporate tax rate of 30% and assumed a value for imputation credits of 0.25 per dollar of tax paid. This estimate is based on a payout ratio for imputation credits of 70%[32] and SFG Consulting's latest estimate of the market value of distributed imputation credits of 0.35.[33] The estimated cost of corporate income tax has been calculated using the AER's PTRM and is outlined in Table 4.

Other proposed revenue adjustments

The Rules require that the AER allow Endeavour Energy to include revenue increments or decrements that relate to the operation of incentives from the 2009-14 period. The Rules also enable a DNSP to propose a revenue decrement for shared assets arising from the use of assets that provide standard control services to provide certain other services.

[31] Clauses 6.4.3(b)(1) and S6.2.3(c)(4) of the Rules.

[32] NERA, The payout ratio, June 2013. p.13.

[33] SFG, Updated dividend drop-off estimate of theta, June 2013, p.31.

Proposed EBSS revenue increment

We have applied the EBSS scheme outlined by the AER in its determination for the current 2009-14 period. This provides estimated carryover amounts for the 2014-19 regulatory period as set out in Table 9. We have provided the calculation of this EBSS carry over amount in Attachment 4.03.

Table 9: Forecast EBSS Adjustments

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
EBSS adjustments	95.1	31.7	39.2	31.0	0.0	**197.0**

We are committed to reducing costs rather than passing them on to customers. However, to ensure that the operation of the EBSS did not impose duplicate penalties on Endeavour Energy, we lodged, and the AER subsequently approved, a pass-through proposal that was restricted to recognising the retail transaction event only for the purposes of calculating the EBSS.

Proposed DMIS revenue increment

The AER applied the DMIS to Endeavour Energy for the current 2009-14 period. This scheme contains two parts:

- IPART's D-factor scheme that was adopted by the AER to apply to Endeavour Energy
- A Demand Management Innovation Allowance (DMIA)

The D-factor that applied as part of the DMIS for the 2009-14 period was subject to a lag of two years between performance in a regulatory year, and incorporation of the incentive payment in prices. As such, the revenue increment related to our performance under the D-factor for 2012-13 and 2013-14 has not been included in the revenue we have collected from customers in the 2009-14 period. Accordingly, a revenue increment for the first two years of the next period will be included in our annual pricing proposals.

Endeavour Energy was also provided with an annual allowance of $0.6 million ($2008-09) in the current regulatory period for DMIA. Any expenditure not spent or not approved by the AER will be returned to customers in 2015-16 when the results of DMIA expenditure for the 2009-14 are known.[34]

Proposed shared asset revenue decrement

The AER may reduce Endeavour Energy's annual revenue requirement for a regulatory year to reflect the costs of assets that it is recovering through the provision of other services (shared asset cost reduction). In making this decision, the AER must have regard to the shared asset principles and the shared asset guideline.

One of the shared asset principles is that a shared asset cost reduction should be applied where the use of the assets other than for standard control services is material. The AER's shared asset guideline sets out its approach to making a reduction to a DNSP's annual revenue requirement to reflect the use of shared assets, including the definition and calculation of materiality.

The use of shared assets is material when a DNSP's annual unregulated revenue from shared assets is expected to be greater than 1% of its total smoothed revenue requirement for a particular regulatory year.[35] If this material threshold is not met, no shared asset cost reduction applies.[36]

[34] AER, Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme, November 2008, p3.
[35] AER, Better Regulation, Shared Asset Guideline, November 2013, p8.
[36] AER, Better Regulation, Shared Asset Guideline, November 2013, p6.

4 BUILDING BLOCK PROPOSAL

We have applied the AER's shared asset guidelines and calculated the materiality of our use of shared assets to earn unregulated revenue. The calculation of materiality for each year of the 2014-19 period is shown in Table 10 below.

Table 10: Materiality of shared asset use

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Forecast unregulated revenue from shared asset	5.4	5.7	5.6	5.7	5.8	**28.2**
Annual smoothed revenue	996.8	972.4	971.4	967.5	973.2	**4,881.2**
Materiality percentage	**0.54%**	**0.59%**	**0.57%**	**0.59%**	**0.59%**	**0.58%**

Consequently, no shared asset cost reduction to the proposed annual revenue requirement for any regulatory year of the 2014-19 period is necessary. Accordingly, we have not modified the PTRM to accommodate any adjustment.

Proposed revenue requirements

Endeavour Energy is committed to alleviating electricity price pressures on customers over the next regulatory control period. Our proposed revenue requirement for the 2014-19 period is $5.3 billion, a 5% real reduction compared to the 2009-14 period.

Annual revenue requirements

In the previous section we set out our proposed building blocks. The addition of the building blocks are used to derive Endeavour Energy's unsmoothed total proposed annual revenue requirement, as set out in Table 11 below:

Table 11: Unsmoothed annual revenue requirement for 2014-15 to 2018-19

$m; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Annual unsmoothed revenue requirement for standard control services	1,050.3	982.9	1,053.2	1,078.9	1,090.4	**5,255.7**

This revenue will be smoothed and recovered from our customers via network tariffs (or charges). These charges reflect the recovery of the efficient expenditure we need to invest in our network, to operate and maintain it and comply with our regulatory obligations. They also provide a reasonable return on our investment in the network.

Adjustment to annual revenue requirement for the transitional year

Endeavour Energy's annual revenue requirement (ARR) for its subsequent regulatory control period must be fully adjusted for the difference in the Annual Revenue Requirement (ARR) approved for the transitional determination, and the ARR determined for 2014-15 as part of its subsequent regulatory control period.

As part of the AER's transitional determination, the ARR included amounts relating to types 5-6 metering and ancillary network services. This was due to an anomaly in the Transitional Rules that prevented the reallocation of type 5 and 6 and ancillary network services costs in 2014-15 despite the change in classification. We consider it appropriate that any adjustment made to this or any component of the 2014-15 ARR be made to the same customer base.

As the outcomes of this determination process are unknown, we are not in a position to propose a revenue adjustment at this stage. Once the AER releases a draft decision for this proposal we may be able to include an indicative adjustment as part of our revised submission in January 2015.

Proposed smoothed revenue and X-factors

Customer research has consistently shown a preference for stable, smooth price movements between years. To minimise price variations over time we need to take into account changes in the level of revenue required to meet efficient costs, as well as changes in energy consumption over time.

To minimise price variations over time we need to take into account fluctuations in the ARR over the course of the regulatory period. As discussed in the sections below, in deciding on the proposed smoothed revenues and the resultant X-factors we have considered:

- the complexities that arise from the inclusion of the transitional year
- forecast changes in energy consumption over time
- the NER requirement to minimise differences in required revenue in the last year.

This smoothed revenue profile has been calculated using the AER's PTRM and ensures that our proposed revenues are equal to required revenues in net present value terms. These models are provided in Attachment 4.02.

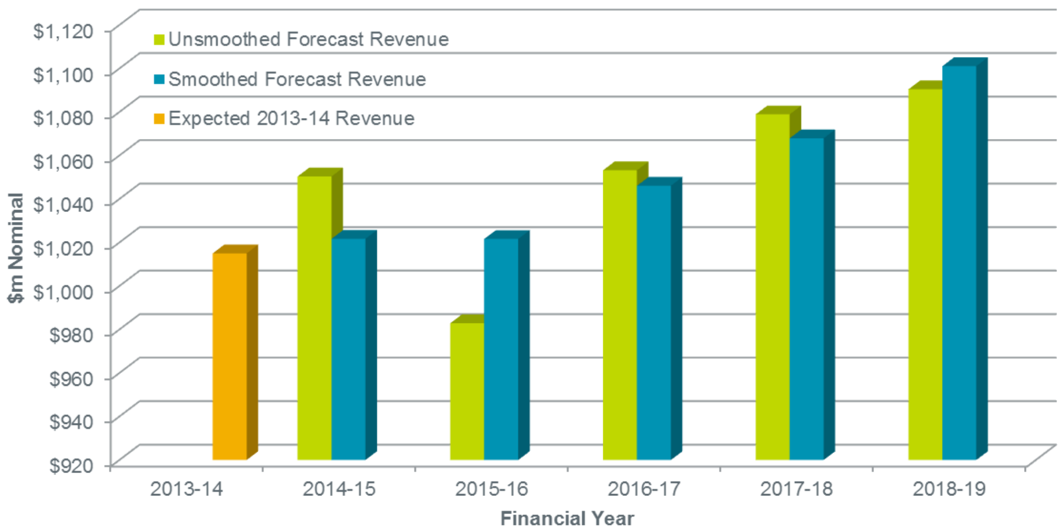
Table 12: Proposed smoothed annual revenue requirement for transitional year and subsequent years

$m; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Annual smoothed revenue requirement for standard control services	1,021.7	1,021.6	1,046.1	1,067.9	1,101.1	**5,258.3**

We have taken customers' preference for pricing stability between years and the requirement for smoothing into account when developing our proposed revenue for 2014-19. As demonstrated in Figure 9, we have smoothed revenues so that annual revenues do not fluctuate greatly between regulatory years. In addition, we have aimed to minimise, as far as practicable, the difference between smoothed and required revenues in 2018-19.[37]

[37] As per clause 6.5.9(b)(2) of the NER

Figure 9: Indicative annual and smoothed revenue requirements



The 2014-19 revenue requirements include the EBSS carry over amounts with other supporting inputs as detailed in Table 4.

The X-factor represents the real percentage change in the smoothed revenue for each year of the 2014-19 regulatory period. The X-factor is important in ensuring that we comply with the control mechanism.

Table 13: X-factors used to smooth revenues (% change in real revenues), excluding inflation

%; Real	2014-15	2015-16	2016-17	2017-18	2018-19
Distribution x-factors	1.80%	2.45%	0.11%	0.40%	-0.59%

Note: A positive revenue X-factor denotes a real revenue reduction.

In the sections below, we note that our smoothed revenue and resultant proposed X-factors have been influenced by three factors.

Energy consumption

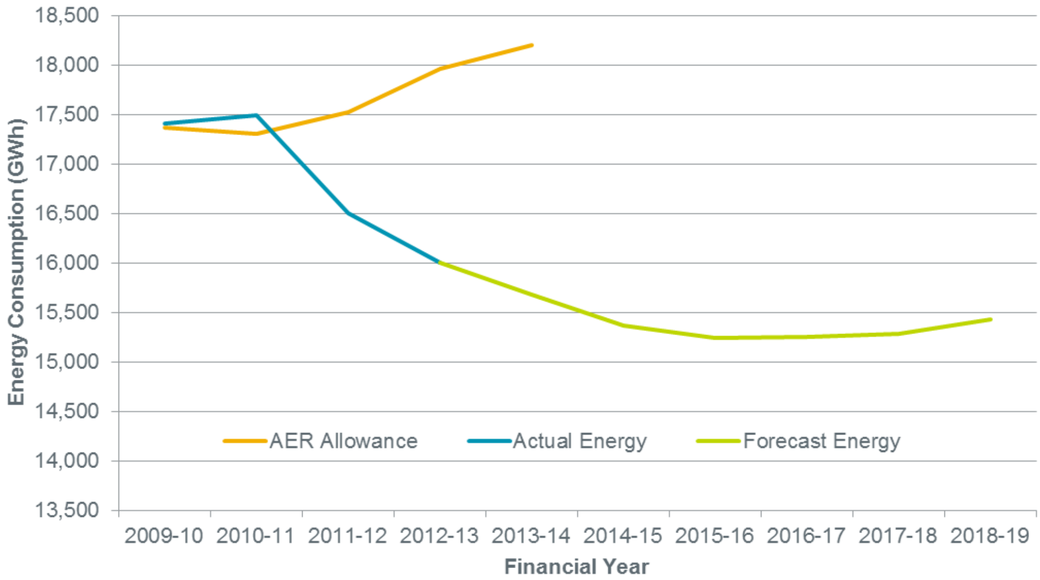
Changes in energy consumption impact the prices customers pay for electricity. For example, if the required level of revenue drops in the transitional year, but then rises again in subsequent years[38] and we do not attempt to smooth revenue recovery over the full 2014-19 period, customers could face pricing volatility over the period.[39] Alternatively, if energy consumption falls and required revenue remains at the same level, then average unit charges would need to increase.

Figure 10 depicts actual energy consumption and the AER approved energy consumption forecasts for each year of the current regulatory period. It also shows the energy forecasts for the each year of the 2014-19 period. This forecast is based on information available as at the end of November 2013 and has been used to calculate the indicative prices for the transitional year.

[38] Rise and fall in revenue may reflect the lumpiness of the expenditure profile.

[39] Assuming energy consumption remains constant.

Figure 10: Energy volume forecast



The annual energy consumption across our network is expected to fall by 11% over the 2009-14 regulatory control period with a final-year difference between AER-approved forecast and our updated energy consumption projection of 14%. Variances in total energy delivered and AER allowances are expected to result in an estimated revenue shortfall of $193 million.

Underlying our energy consumption forecast above, we expect, on average, our customers will continue to reduce their use of electricity by 1.6% per annum over the five years commencing 1 July 2014. This forecast reduction in consumption is attributable to economic pressures on businesses and manufacturers, our customer response to electricity price rises, government-led energy efficiency programs, and the wind-up of the NSW solar bonus scheme and ongoing investment in photovoltaic generators. Our actual and forecast energy consumption is outlined in Figure 10.

Under the revenue cap control mechanism, reduced energy consumption would place upward pressure on electricity bills in subsequent years to achieve the revenue cap outcomes; however, we are striving to contain our share of customers' electricity bill increases to at or below CPI for the next regulatory control period.

Minimising difference between required revenues

A further relevant consideration for a revenue smoothing profile is the Rules require that revenues be smoothed such that it minimises the difference between required revenues and expected revenue recovery in the final year of the regulatory period (i.e. 2018-19).[40]

This is intended to minimise the potential for price shocks between the 2014-19 period and the subsequent regulatory period.[41]

[40] NER, cl. 6.5.9(b)(1)

[41] For example, if revenues are smoothed over five years in such a way that smoothed revenue recovery in 2018-19 is significantly less than the level of revenues required to meet efficient costs, then in the following regulatory period prices may need to increase significantly to meet the required level of revenues.

Indicative charges and bill impacts

Endeavour Energy is striving to contain average increases in our share of customers' electricity bills at or below CPI over the next regulatory control period. This section sets out our proposed prices and expected bill impacts for 2014-19 period.

We have examined our strategies, processes and procedures to identify scope for savings. This reflects our commitment to alleviate price pressures and our ongoing effort to be effective and efficient in everything we do, without compromising the safe, sustainable and reliable supply of electricity. In the following sections we identify:

- the movement in average distribution charges, based on the proposed X-factors and energy consumption profile discussed above
- provide indicative DUOS prices for each year of the regulatory control period.[14]

Movement in average distribution charges

A useful indication of how average prices could move over the regulatory control period is demonstrated in the table below:

Table 14: Change in average distribution charges based on latest energy forecasts (% change, real), excluding inflation

%; Real	2014-15	2015-16	2016-17	2017-18	2018-19
Weighted average change in distribution charges	-1.26%	-1.25%	-1.25%	-1.25%	-1.25%

We know that customers value bill stability.[42] As shown in Table 14, we expect the proposed smoothed annual revenue requirement, combined with our forecast for energy consumption, will mean customers receive a smooth annual real reduction for each year of the 2014-19 period.

This average change in charges is based on our latest energy consumption forecasts over the 2014-19 period. Energy consumption has been volatile over recent years and while every effort has been made to forecast accurately:

- if energy consumption falls below our forecast, average distribution network charges will need to increase more than in Table 14, or
- if energy consumption rises above our forecast, average distribution network charges would decline below what is shown in Table 14.

It should be noted that this forecast does not incorporate changes in the relative contribution of each tariff and/or tariff component to overall distribution revenues over the five-year period. This may change based on energy consumption and pricing decisions for each year. This is further discussed in Chapter 9 of our proposal.

[42] Attachment 2.03, Customer Engagement Survey Qualitative Summary Report, May 2013, page 17.

Indicative prices

Table 15 outlines indicative DUOS prices for 2014-19 based on our proposed bundled revenue and our latest forecast of energy volumes.[43]

Table 15: Indicative average DUOS for 2014-15 to 2018-19

c/kWh; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Average
Residential customer consuming 5MWh p.a.	12.3	12.5	12.6	12.8	12.9	**12.6**
Small business customer consuming 26MWh p.a.	9.2	9.4	9.5	9.6	9.7	**9.5**

The prices outlined above are indicative only and will be updated in our pricing proposal for 2014-15, to reflect:

- the AER's decision on allowed revenue for the 2014-15 transitional year and any differences between the revenue determined for the 2014-15 year and the transitional revenue determination
- updated energy consumption forecasts
- any changes in the relative portion of revenues recovered from each tariff and tariff component.

We also note that the prices outlined above are only a portion of the total network use of system (NUOS) charge to customers. NUOS charges include the cost of the services provided by the NSW Transmission Network Service Provider (TransGrid) as well as the recovery of an amount to satisfy obligations under the NSW Climate Change Fund (CCF). These components are outside our control.

Pass-through events

The pass-through mechanism in the NER recognises that a DNSP can be exposed to risks beyond its control, which may have a material impact on its costs. A cost pass-through allows a business to seek the AER's approval to recover (or pass through) the costs of a defined, unpredictable, high-cost event.

A building block proposal may include a proposal as to the events that should be defined as pass-through events, in addition to the events defined under NER clause 6.6.1(a)(1).

Endeavour Energy has undertaken a thorough risk assessment of its operations using the bow-tie risk analysis methodology.[44] We have cross-checked the results of this analysis against our historical risk register and have also had our risks independently assessed by Ernst & Young (EY).

From our analysis we have identified a number of risks which we consider should be managed via a nominated cost pass-through event rather than an allowance in our regulatory proposal. While Endeavour Energy does have in place prudent risk mitigation measures, the events we are proposing are those which are beyond our control to prevent, are expected to have significant or catastrophic cost impacts and have a low likelihood of occurrence.

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[43] For a full listing of indicative prices, as required by clause 6.8.2(c)(4) of the NER, and bill impacts for the 2014-19 period, refer to tables 7.6 and 7.7 of the Reset RIN and our PTRM attached to this proposal.

[44] The bow-tie methodology considers plausible worst case hazardous events and identifies both the preventative controls to reduce the likelihood of the risk occurring and mitigation controls to reduce the consequence of the event.

4 BUILDING BLOCK PROPOSAL

We propose the following events be approved as part of our regulatory determination, which are to apply as nominated pass-through events during the 2014-19 regulatory control period:

- Insurance cap event
- Natural disaster event
- Terrorism event
- Insurer's credit risk event

In proposing these events, we have regarded the considerations in Chapter 10 of the Rules and consider that each event meets the necessary requirements to be approved as a nominated cost pass through event. Endeavour Energy's proposed definition for these events and detailed assessment of how they meet the pass-through event considerations is provided in Attachment 4.10 of our proposal.

5 CAPITAL EXPENDITURE

Summary

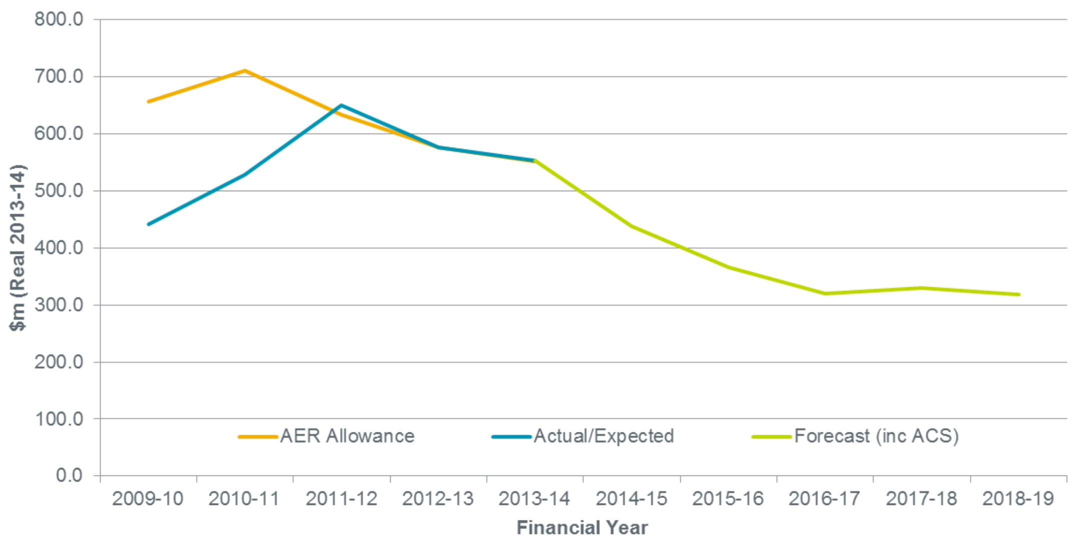
Our proposed capital program of $1.7 billion will ensure we efficiently manage growth in demand and connections, which is expected to occur in pockets of our service area, and that we deliver affordable, safe and reliable electricity services to our customers in a financially sustainable manner.

The purpose of this chapter is to identify the circumstances underlying our forecast, and the method used to develop our proposed capital expenditure. We also set out our investment plans and the key highlights of the program.

Our forecast capital expenditure is 43%[45] lower than allowed capital expenditure for 2009-14.[46] This reflects that we will have achieved the step change in the supply security required under our licence conditions. The lower capital expenditure also reflects strategic re-alignment of objectives under industry reform, with a greater focus on minimising prices for our customers and observed reductions in the rate of growth in peak demand.

Endeavour Energy's proposed standard control services capital expenditure requirements for the 2014-19 regulatory control period is $1,746.1 million as shown in Table 18. The graph below depicts the sum of this and the newly reclassified type 5 and 6 metering capital expenditure when compared to the 2009-14 period.

Figure 11: Total Capital Expenditure Forecast 2010-2019



Investment in the next period is primarily focused on servicing key, high-growth areas within our network, in particular North-West and South-West Sydney. We will also continue to focus on replacing deteriorated assets in order to maintain a sustainable network.

45 Inclusive of type 5 and 6 metering and ANS costs for comparison in real terms to the 2009-14 period allowance in real terms.

46 In real terms.

5 CAPITAL EXPENDITURE

Outcomes in the 2009-14 period

Capital expenditure in the 2009-14 regulatory control period was largely focused on improving network security and reliability as reflected in the NSW Design, Reliability and Planning Licence Conditions. Having achieved substantial progress towards compliance, these issues will no longer be a focus for the 2014-19 regulatory control period. Improved processes also meant we have delivered our capital program at a lower cost than expected.

Over the last ten years, we have delivered significant improvements to our customers. We have improved reliability, increased security of supply, and replaced deteriorated assets that posed safety risks to our customers and workforce. In delivering our programs we have focused on efficiencies and innovations, including targeted efficiencies to the capital program for the 2009-14 period.

This section identifies the focus and outcomes of the 2009-14 regulatory period and explains why we spent less than our expenditure allowance during the period. This section provides a useful background to the forthcoming analysis on forecast capital expenditure.

Focus of the current regulatory period

As discussed above, the projects that we undertake on the network at any given time are a direct outcome of the issues and challenges facing the business currently and in the future. Our network strategy at the commencement of the 2009-14 regulatory period was shaped by the following challenges:

- meeting the NSW Government's initiative for increasing the security and reliability of electricity supply as reflected in the NSW Design, Reliability and Performance (DRP) Licence Conditions
- ensuring ageing network assets did not adversely impact on network reliability and security of supply
- servicing growth in peak demand and customer connections in our network area

Security and reliability

During the current regulatory control period our electricity network, along with Ausgrid and Essential Energy networks, were subject to licence conditions which specified minimum requirements relating to the way the network was planned and the frequency and number of unplanned outages that occur on the network.

Following the introduction of the DRP Licence Conditions in 2005, the NSW Government amended the conditions in 2007. The amendments imposed specific standards around the level of load at risk in the network and the timeframe for achieving these standards. Specifically, the licence conditions included requirements that had to be attained by 2014.

The amendments to the licence conditions required us to escalate our substantial investment program, which began during the 2004-09 regulatory control period, to meet the 2014 compliance date.

Asset renewal

Many elements of our network were built during the construction booms from the 1960s through to the 1980s. At the beginning of the regulatory period, 15% of our zone and sub-transmission substations were at replacement age, largely as a result of sustained periods of significant demand growth and under investment during the 1990s and early 2000s under the previous regulatory regime.

In order to maintain the safety and reliability of the network, we invested a significant amount of funds in renewing these ageing assets. As discussed on page 58 of this proposal, we have achieved a more sustainable weighted average remaining life of our network assets and our intention is to maintain this sustainable profile into the future.

Demand growth

Growth in peak demand was a key driver of network capital investment. Over the last decade this demand growth was fundamentally driven by an increased penetration of residential air conditioning units. The increased uptake of air conditioning in existing dwellings, in particular, caused peak demand to increase significantly across both our existing and expanding network.

In recent years air-conditioning load has started to reach saturation point in our network. As a consequence, peak demand growth from existing connections no longer present a significant driver of network expenditure in the next regulatory control period.

Outcomes in the 2009-14 period

The 2009-14 regulatory period saw us embark on the largest investment program in our history, driven largely by the need to increase the security and reliability of our network infrastructure as required under our licence conditions. In order to deliver the program, we developed a number of strategies that focused on efficiency and sustainability. The application of these strategies enabled us to deliver our capital program without using our full expenditure allowance. This underspend will be passed through to customers in the 2014-19 regulatory period in the form of a lower-than-expected regulated asset base and therefore a lower contribution to network prices.

NSW Design, Reliability and Planning Licence Conditions

Under the DRP Licence Conditions, we were generally required to build our network so that if one system element failed, there would be no interruption to supply. The conditions also required us to restore supply within defined timeframes where there was an outage. While we used innovative ways of restoring the network after an outage, the licence conditions also required a significant amount of infrastructure to be present as 'back up', or contingency.

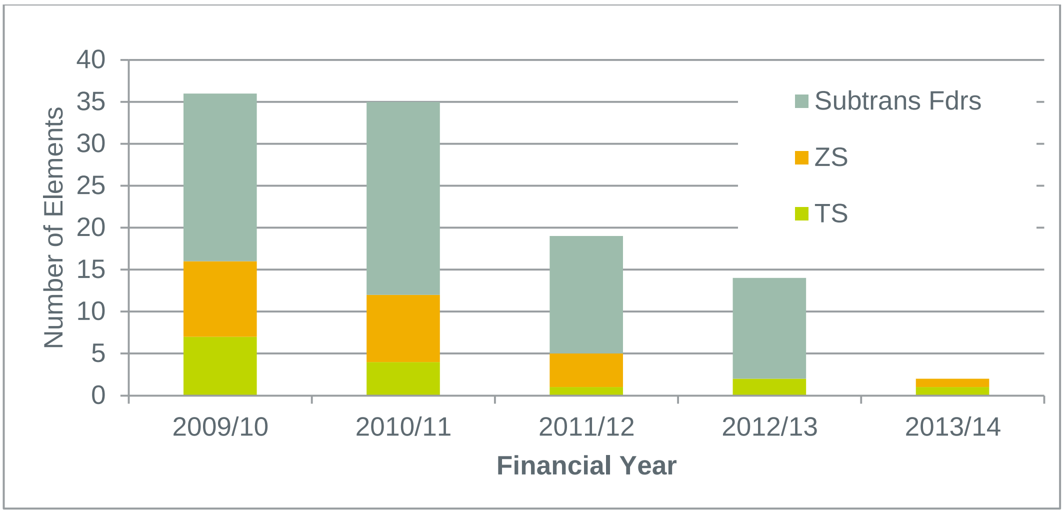
What we delivered in 2009-14

We undertook substantial investment in our network during the current period. Some of the assets we delivered this period were - *9 transmission substations; 43 sub-transmission feeders; 27 zone substations; and over 500 distribution feeders.*

At the beginning of the 2009-14 regulatory period we identified that substantial investment was required across the network to meet the requirements of the DRP Licence Conditions. To achieve compliance with these mandatory standards, major investments were required across the network.

Throughout the regulatory period, we made significant inroads towards achieving compliance with the licence conditions, as illustrated in Figure 12. For example, the number of non-compliant sub-transmission network elements fell from 36 in 2009 to two in 2014. Generally, these improvements have provided sufficient capacity in our existing network to meet forecast demand growth and will continue to do so in coming years.

Figure 12: Non-compliant sub-transmission network elements (DRP Licence Conditions)

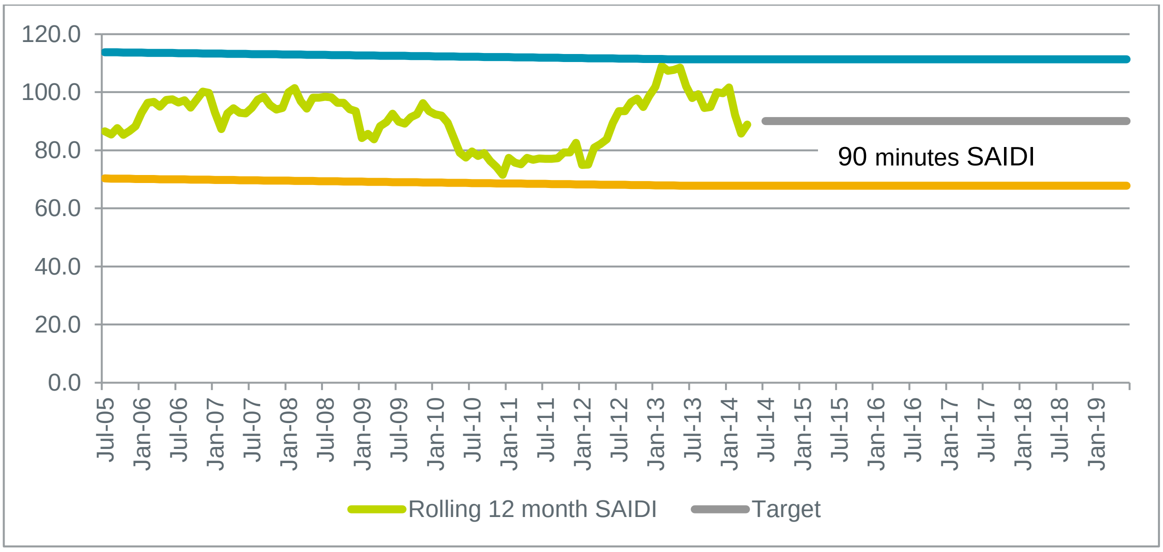


Reliability

Reliability of supply is a key driver of customer satisfaction and an important aspect of our network performance. We measure the reliability of our network with the System Average Interruption Duration Index (SAIDI). This is a measure of the number of unplanned minutes that customers, on average, are without electricity each year.

Between the period 2009-10 and 2010-11 our network reliability improved substantially, as demonstrated by a reduction in SAIDI. However, an increase in the 2012-13 year is evident in the figure below. This increase was attributable to a number of weather events and the methodology used to calculate SAIDI. Our analysis demonstrates that a more representative index can be produced. Refer to Attachment 0.14 for our analysis and our proposed approach for measuring reliability performance during the 2014-19 period .

Figure 13: Endeavour Energy – SAIDI trends and targets



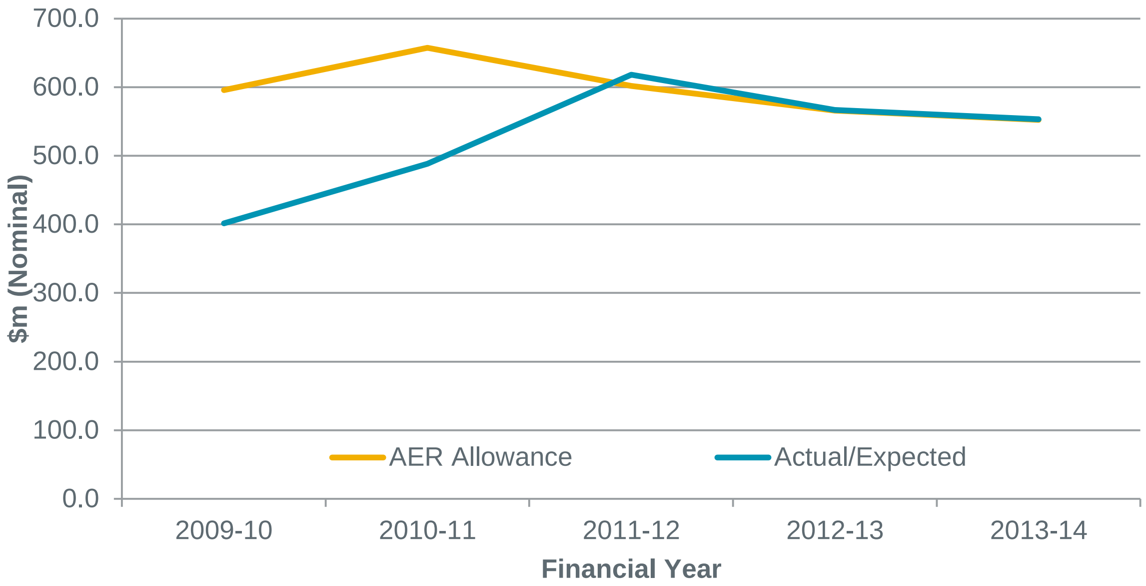
During the course of our consumer engagement program, consumers have recognised an improved level of reliability and security in our network over the 2009-14 regulatory period. It also became clear that consumers did not believe that future improvements in reliability were required, particularly not at the expense of higher prices. Our expenditure plans will in future focus on maintaining current reliability rather than making further overall improvements in this area.

5 CAPITAL EXPENDITURE

Variations in capital expenditure

During the 2009-14 regulatory period we delivered capital investment totalling $2,628 million (nominal), falling lower than our nominal allowance of $2,973 million, with the majority of underinvestment occurring in 2009-10 and 2010-11.[47]

Figure 14: Actual vs. allowed capital expenditure



A relevant consideration for the AER is whether variations to forecast in the previous period have been explained and addressed in developing the forecast capex for the 2014-19 period. This is to provide assurance to the AER and our customers that there are no systematic forecasting errors underlying our proposed capex. In the sections below we identify the key reasons for variation.

While reductions in demand growth compared to forecasts can explain some of the reductions, we note that there have been a number of relevant factors that explain the reductions. In particular, we note that our peak resourcing strategy and industry reform have also driven reductions to our capital program. We also note that delivery issues also played a part in a lower capex profile to forecast, this was related to the significant increase in resourcing required to deliver the program.

Peak resourcing strategy

At the beginning of the 2009-14 regulatory period, we were faced with the challenge of delivering a significant network capital investment program for customers that was 50% larger than any other past program. Of particular note, the program represented a peak in capital investment volumes for our company, with a return to sustainable long term capital investment from 2014 onwards.

In the interests of building customer value, we implemented a range of initiatives to improve the efficiency and sustainability of capital program delivery.

We enhanced delivery by improving project management and increasing the use of skilled external resources through a Peak Resourcing Strategy. Peak resourcing involved the use of external contracted resources for key physical program delivery areas, as well as the engagement of ‘term-based’ staff to project-manage the

[47] In accordance with NER S6.1.1(6), capital expenditure for each of the past regulatory years of the previous and current regulatory control period (categorised in the same way as for the capital expenditure forecast) is provided at Attachment 5.17.

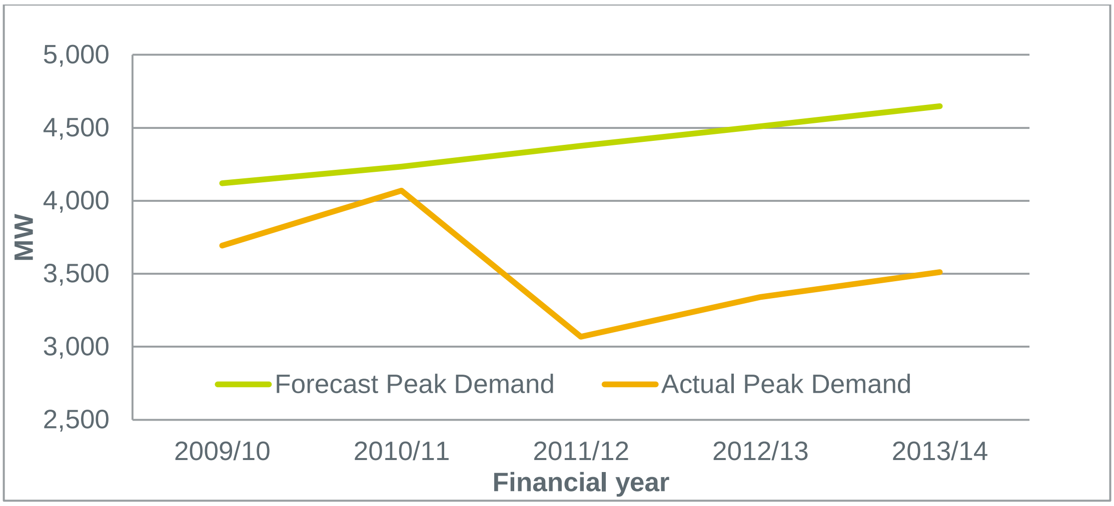
implementation of the peak investment program. Under this strategy over 81% of the value of the capital investment during the 2009-14 period was tested in the market and externally sourced.

Moreover, this strategy delivered peak workloads at a lower than expected cost, without increasing employee numbers to unsustainable levels in the longer term.

Forecast vs actual demand

Right along the eastern seaboard, electricity peak demand fell below forecast over the 2009-14 regulatory period.

Figure 15: Endeavour Energy – actual vs. forecast peak demand (MW)



This was due to:

- the closure of large manufacturing companies
- the penetration of more energy-efficient appliances
- changing consumer behaviour in response to prices.

Through our annual network planning process, we were able to reset our planning schedule and defer a number of demand-driven projects, including:

- Collimore St (Liverpool CBD) Zone Substation - $29 million
- Holsworthy Zone Substation - $24 million
- West Epping Zone Substation - $31 million
- Minto area distribution feeders - $41 million
- High Voltage Development Program - $100 million

The deferral of these projects helped to reduce capital expenditure over the 2009-14 regulatory period by $225 million. In addition to these major demand-driven projects a number of other smaller projects were deferred for various reasons.

The difference between forecast and actual peak demand was attributable to a number of factors:

- **Economic conditions**. Following the Global Financial Crisis in 2008, consumer confidence remained low for prolonged periods throughout the 2009-14 regulatory period, with consumers being more frugal amid concerns about the health of the global and Australian economies and fragile domestic job market. Weaker than expected economic conditions led to some business closures and production cut backs, which had a negative impact on energy consumption. Further, the slower growth in new customer connections stemming from a slow housing market (with exception of the northwest and southwest Sydney growth sectors) also contributed to lower energy volumes than expected.

- **High Australian dollar**. Movements in exchange rates and the strong Australian dollar resulted in a number of large companies curtailing activities or moving offshore. For example, two of our major loads, reduced consumption by 77% and 40%, respectively, since 2010/11. We estimate this led to demand being reduced by up to 100MW each year over the previous two years.
- **Price increases.** Throughout the 2009-14 period customers responded to electricity price increases by conserving electricity and signing up to solar. This contributed to a fall in electricity consumption in Endeavour Energy's network area and across the state more generally.
- **Relatively mild winter and summer seasons**. In recent years, our network has been exposed to increased volatility in summer and winter temperatures. While we experienced a number of mild winter and summer seasons, this was contrasted by a record-breaking maximum temperature of 46 degrees in early 2013. Given the strong relationship between temperature and demand, such volatility makes it particularly difficult to accurately forecast electricity peak demand.
- **An increase in rooftop solar systems (PV)**. An increase in the penetration of 'net metered' rooftop PV systems in residential and small and medium size enterprise sectors also contributed to lower electricity use. This will become a more significant issue during the next regulatory period (particularly post-December 2016) when the NSW Solar Bonus Scheme ends and large numbers of customers transition from 'gross' to 'net' metering to help reduce their electricity bills.
- **Energy efficient appliances and efficiency schemes** – Energy efficiency is helping to drive down electricity consumption. The introduction of the BASIX (Building Sustainability Index) in 2004 and the Energy Saving Scheme in 2009, together with more energy efficient electrical appliances and lighting, as well as the increased use of gas for cooking and heating, all have contributed to lower electricity volumes.

While the external landscape will continue to evolve, we are confident that our demand forecasts adequately take into account the changing economic climate and evolving basis of consumption. These forecasts are discussed in more detail in Attachments 4.04 through to 4.09 and Attachment 5.18 and 5.19.

Delivery and prioritisation

Our significant investment program in the 2009-14 period placed delivery pressures on Endeavour Energy in the early years of the period. We responded to these programs through blended delivery models, but in some cases our ability to deliver the program fell behind schedule.

We consider these delivery issues will not arise in the 2014-19 period due to improved processes now implemented, and substantially reduced workload from a smaller capital program.

In addition to this, Endeavour Energy also re-prioritised its program to respond to actual conditions experienced in the period. For instance, we deferred the Marayong renewal program, worth $23 million, through an enhanced understanding of asset condition indicators and reviewing our renewal criteria. Our forecast capital expenditure for 2014-19 has incorporated the improvements we have made over the period.

5 CAPITAL EXPENDITURE

Forecasting methodology

Our forecasts are developed through a detailed and rigorous process, undertaken by a team of experienced network planners who have a deep and extensive understanding of the network. Our forecasting process uses contemporary and sophisticated techniques to identify network constraints. This allows us to prepare expenditure forecasts that are prudent and efficient, and represent the best value for money for our customers.

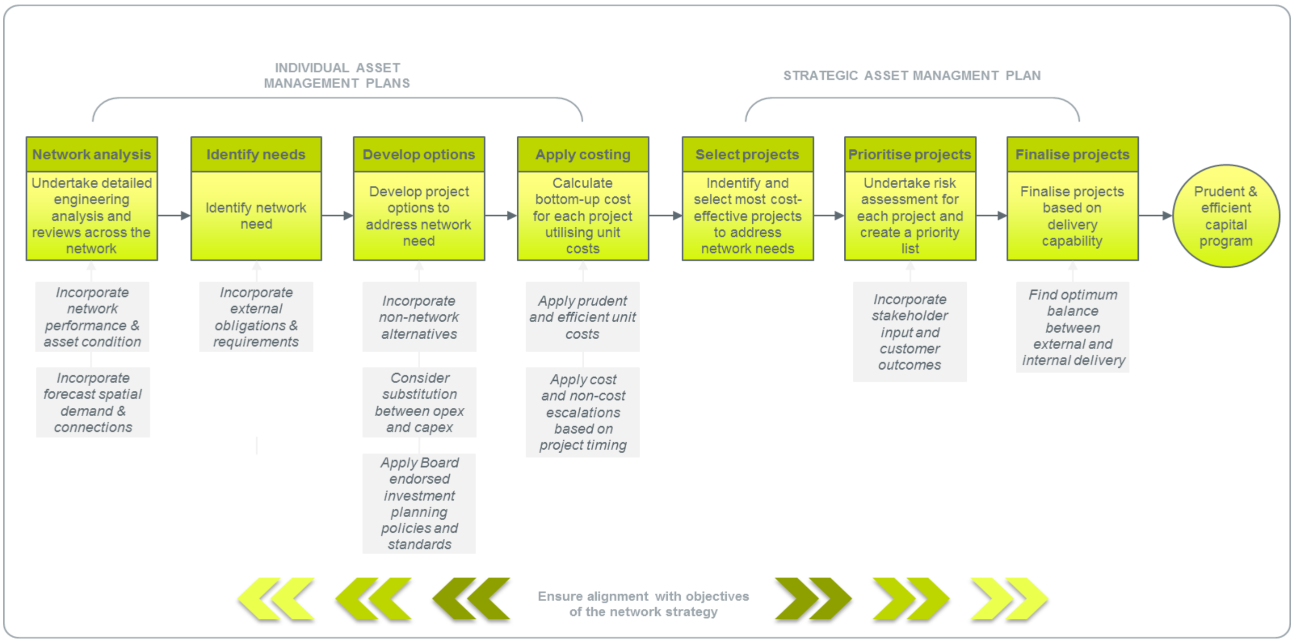
Establishing five-year capital expenditure forecasts that are prudent and efficient is a complex undertaking as a wide range of factors need to be considered. Furthermore, our capital expenditure forecasts need to balance the competing interests of various stakeholders – our customers, our shareholder, the regulator and our business itself – particularly in the current environment which has a strong focus on reducing the impact of rising electricity prices. At the same time, our expenditure forecasts must provide us with capacity to meet demand over the next regulatory period, comply with all applicable regulatory obligations, and allow us to maintain the safe, secure, reliable and sustainable supply of electricity to our customers.

Our capital expenditure forecasting methodology is designed to comprehensively take into account all of the above considerations.

Approach to forecasting capital expenditure

The key steps involved in our capital expenditure forecasting process are depicted in the figure below. While this process is used to develop the five-year capital expenditure forecasts for the 2014-19 period, the process is a rolling 10-year forecast which is also applied annually to our capital program. This means that each proposed project in the capital expenditure program is based on up-to-date information, which allows us to reset our project plan to account for within period events. Moreover, the annual review process ensures that the projects that proceed through the approval process have a clear and defensible justification.

Figure 16: Endeavour Energy Forecasting Process



5 CAPITAL EXPENDITURE

Individual asset management plans are developed to identify and forecast required capital works for each capital expenditure category. The required capital works have been determined based on network need, which is identified using:

- detailed engineering analysis of the network
- current asset and network condition reports
- spatial peak demand forecasts
- regulatory obligations and requirements
- customer concerns identified through the customer engagement plan.

Once a particular network constraint has been identified, project options to address the network need are developed. At this stage we consider a number of options to address the identified constraints including non-network alternatives and operating expenditure substitution possibilities. Each project option is then costed. For the majority of capital expenditure categories we have used a ‘bottom up’ method to derive the forecast expenditure. Our bottom-up method makes use of:

- historical unit costs (modified where appropriate to reflect site-specific factors)
- volumes based on historical experience and network need
- current labour and contractor rates
- current material and equipment costs.

We have used a ‘top-down’ approach to forecasting some capital expenditure categories. Forecast work in these categories is generally constant in scope from year-to-year or related to network growth and can be forecast at a high level. We have also used a ‘top-down’ approach to test the veracity of some of our bottom-up forecasts, in particular our replacement expenditure forecasts.

The specific forecasting approach and key inputs for each capital expenditure category is outlined in the forecasting methodology set out in Attachment 0.08.

The annual capital works plan which underlies the capital expenditure forecasts is set out in the Strategic Asset Management Plan. This plan sets priorities and summarises the required investment to maintain the ongoing capability of the network. Specific high-value projects to address network needs are selected using our Network Investment Options process. As part of this process we consider all feasible options to address the network constraints, and select an option which represents least cost, or maximises the benefits in net-present terms. The Network Investment Options process aligns with the RIT-D planning process and guidelines.

Investment governance and prioritisation

Investment governance framework

In recognition of consumers’ preferences to keep the cost of electricity low, we are constantly looking at ways to advance the efficiency and effectiveness of our planning process to ensure that consumers receive value for money from every dollar invested in the network.

To deliver on this objective, as part of the Networks NSW reform program, we have instituted a new Investment Governance Framework to review and rationalise our forecast capital program. The aim of the framework is to ensure that the processes by which investment decisions are made and implemented:

- are compliant with safety, statutory and regulatory obligations and requirements
- are prudent and efficient
- are within a sustainable capital structure for each network business
- ensure that any decisions of significance, which underpin the investment program, are considered and approved by the Board.

In addition to the key benefits above, the Investment Governance Framework facilitates the Board's input into the early stages of the planning process and provides a framework within which the Board will endorse long-term area plans and investment portfolio decisions of significance. In addition, the framework:

- Provides input into the program delivery model. The delivery models drive the demand for labour and skills which may be internally or externally sourced.
- Provides a consistent framework and approval process across Networks NSW which will enable prioritisation of investments within each of Endeavour Energy, Ausgrid and Essential Energy.
- Provides an independent and peer-review process to further test the proposed expenditure.

Project prioritisation

The ability to prioritise planned investments within Endeavour Energy is an important component of the governance framework. The methodology for prioritisation must be consistent, efficient and transparent for it to be effective. Prioritisation must occur within a context of risk analysis and ensure that the risk associated with a prioritisation scenario is clearly articulated.

A prioritisation model is being used for all network projects and programs. The model uses an algorithm based on an assessment of risks and provides a ranking outcome for investments. By using a common model, we can prioritise projects and programs within Endeavour Energy. This will provide the maximum flexibility to the Board and management to balance financial risks and prioritise investments that most effectively mitigate network risks.

For the 2014-19 period, it should be noted that the resultant expenditure level took into account the prudent risk level in Endeavour Energy's circumstances, and was not dependent or related to overall risk across the three NSW DNSPs.

Prudent and efficient

While it is inherently difficult to forecast expenditure requirements over long periods of time, we believe that the process that we use to develop forecasts of capital expenditure result in expenditure amounts that are prudent and efficient. This is because:

- we have a robust demand forecasting process which provides a realistic expectation of future demand and our distribution network's requirements.
- we have taken a holistic approach to considering all possible network and non-network options to address the requirements of our distribution network.
- the capital expenditure forecasts are underpinned by rigorous technical and economic analysis undertaken by experienced network planners who have a deep knowledge of Endeavour Energy's network.
- our project review framework prioritises projects that best meet individual asset needs, having regard to optimal asset utilisation at least cost and delivering value for money for consumers.
- we have undertaken extensive consumer consultation throughout the preparation of our expenditure forecasts and incorporated the concerns of electricity consumers into our planning process.
- we have used our existing asset management planning framework, which is a proven tool for delivering prudent and efficient capital expenditure forecasts.
- our new Investment Governance Framework subjects expenditure programs to end-to-end scrutiny and facilitates Board input into the early stages of the planning process to ensure the reasonableness of our capital expenditure forecasts.
- we have engaged independent consultants to review key inputs to the forecasting process and aspects of our forecasting methodology.

5 CAPITAL EXPENDITURE

Key assumptions

The Rules require us to identify the key assumptions that underlie the capital expenditure forecast. The section below summarises the key assumptions that underlie our forecast of required capital expenditure for the 2014-19 period, with further information on the reasonableness of each assumption provided in Attachment 0.06.[48]

The Rules also require a certification of the key assumptions that underlie that capex (and opex) forecast by the directors of Endeavour Energy. This certification is also provided at Attachment 0.06.[49]

Key assumption	Activities
Legal and organisational structure	The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.
Amendments to Reliability and planning licence conditions	The capital program has been prepared on the basis of amendments to the NSW Design Reliability and Planning Licence Conditions that will come into effect on 1 July 2014.
Strategic management framework	Capex programs have been developed using a strategic management framework that prioritises expenditures for maintaining a safe, reliable and sustainable network.
Forecasts of demand	Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts included in the regulatory proposal.
Labour cost escalation	Forecast labour cost escalation has been set consistent with our Enterprise Bargaining Agreement (EBA) for the period in which the EBA applies. For the period subsequent to the expiry of the EBA, we have set forecast labour cost escalation consistent with the advice provided by an expert independent consultant Independent Economics.
Customer Engagement	Endeavour Energy has engaged with stakeholders in developing its regulatory proposal in accordance with the stakeholder engagement process outlined in the NER.

Forecasting inputs and considerations

This section outlines the inputs and considerations that underpin our forecast capital expenditure at the time of preparing this proposal.

Maximum demand forecasts

Forecasts of maximum demand are a key input in the development of forecast capital expenditure, particularly augmentation capital expenditure. Our network is (predominantly) a summer- peaking network, as it is affected by a number of high-temperature events and lower equipment ratings during summer periods.

In a change from the current regulatory period, NSW distribution businesses will be regulated by the AER under a revenue cap control mechanism in the next regulatory period. It is important to note that under a revenue cap, consumers are generally exposed to the risk of differences between actual and forecast electricity consumption within the regulatory control period. Any shortfall in revenue or excess revenue recovered by the distribution business as a result of actual consumption being different from forecast will be

[48] This information relates to the requirements in Schedule 6.1.1 (4) of the Rules.

[49] This information relates to the requirements in Schedule 6.1.1 (5) of the Rules.

passed through to consumers and reflected in the following year's prices. Therefore, it is imperative that our forecasts are accurate and do not overstate consumption.

While revenue amounts will be reconciled through an overs/unders adjustment each year, our business is still subject to risk. Specifically, if we understate peak demand we may not have sufficient revenue to fund necessary augmentation without forgoing other investments which may have consequential impacts on safety and reliability. Ideally, this risk could be managed through the use of contingent projects. However, it is unlikely a project will meet the threshold, being the higher of $30 million or 5% of our proposed 2014-15 annual revenue requirement.

Our forecast system maximum (peak) demand and customer connection forecasts are provided below. Endeavour Energy's maximum system demand is forecast to grow from 3785 MW in 2014-15 to 4060 MW in 2018-19, representing an annual growth rate of 1.8% over the regulatory control period.

Table 16: Forecasts of maximum demand for the 2014-19 regulatory period

	Forecast year ending 30 June				
	2014-15	2015-16	2016-17	2017-18	2018-19
Maximum demand (MW)	3785	3894	3976	4036	4060
Maximum demand (% growth per annum)	3.5	2.9	2.1	1.5	0.7

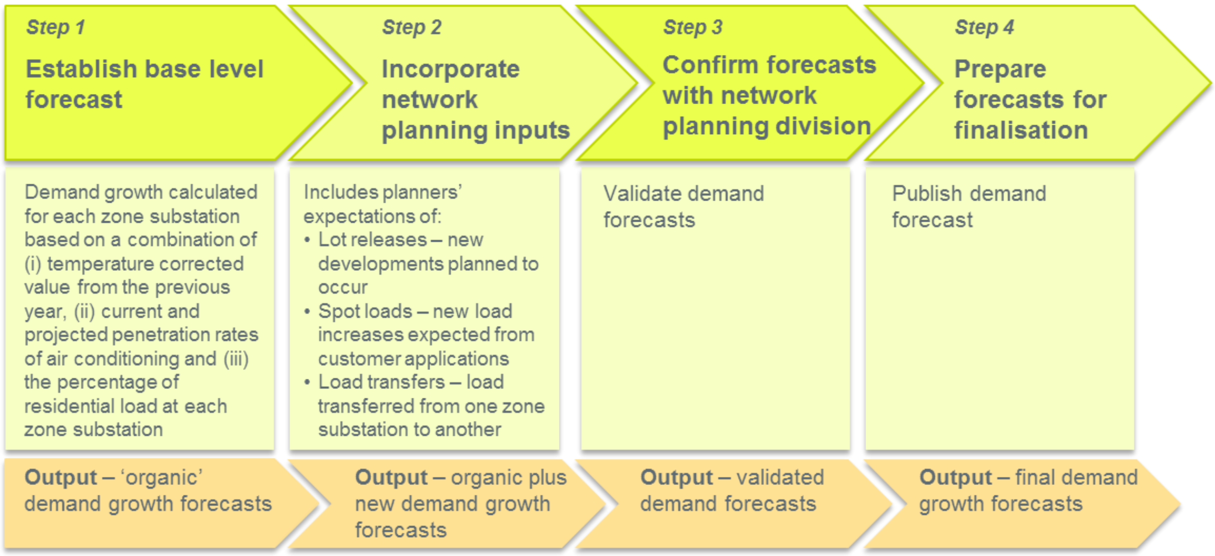
Maximum demand forecasting process

Maximum demand forecast accounts for the total growth from existing customers as well as new customers. We forecast maximum demand for each zone substation, using a 'bottom-up' approach, for both summer and winter peak periods.

Our forecasts incorporate new developments planned to occur in the network, new load increases expected from customer connection applications, as well as electricity that is transferred from one substation to another. Loads that are supplied by embedded generators are also incorporated in the calculation of maximum demand forecasts. Our demand forecasts are 'temperature corrected', to account for the variability of demand with temperature.

The demand forecasting process can be divided into four major steps, as illustrated below. A more detailed description of the process is contained in Attachments 5.18 and 5.19.

Figure 17: Maximum demand forecasting process



Pockets of demand growth

As discussed earlier, Endeavour Energy has experienced a decline in demand growth across its network, which is consistent with most other networks in the National Electricity Market.

While peak demand growth is the primary driver of network investment, a downward trend in demand growth at the aggregate level does not automatically signal a reduced need for network investment. It is important to recognise that investment in network infrastructure is driven by both local and regional factors. As these factors are often quite different between, and within, each network area, it is necessary to analyse peak demand at a local level within the network.

The NSW Government's Sydney Metropolitan Plan states that in the 25 years from 2011 to 2036, Sydney's population is expected to reach six million people. Some of this growth will occur in new areas and the remaining within Sydney's existing footprint.

Growth within infill areas in the existing footprint can, with minor augmentation works, generally be serviced by existing network infrastructure. However, depending on individual circumstances, there are exceptions.

The major priority target areas identified in the Metropolitan Plan are the greenfield sites in the North-West and South-West Growth Centres. Our network is responsible for servicing these growth centres, and major infrastructure works are required over the coming years.

> *"The Metropolitan Plan forecasts also highlight the need to create the capacity for 760,000 more jobs across Sydney by 2036 – with 50% located in Western Sydney. This would include a proposed doubling of projected employment in south-west Sydney and further strengthening of Parramatta as Sydney's second CBD."*
>
> NSW Government Department of Planning and Infrastructure

North-West and South-West Sydney Growth Centres

Widely regarded as the fastest-growing corridor in the State, Sydney's North-West and South-West Growth Centres are expected to accommodate up to 181,000 new dwellings and land for employment for around 500,000 new residents over the next 25 to 30 years.

In terms of large energy users, Western Sydney is Australia's largest manufacturing region, with a number of major multinational companies operating within the area, including BHP Billiton, Coca-Cola Amatil, Qantas, Sony and Canon.

Strong economic growth is expected in the growth centres over the 2014-19 regulatory period, with a series of major transport, health and education projects planned for the region. Recent announcements by the Federal Government on the siting of Sydney's second airport at Badgery's Creek within Western Sydney will drive further demand growth in the mid term. Further implications of this announcement will be considered in our revised submission.

Moreover, we are forecasting substantial demand growth in these pockets over the 2014-19 regulatory period.

To ensure prudent and efficient capital investment in the growth centres, we work closely with development proponents to achieve 'just-in-time' infrastructure investment. Augmentation planning ensures that spare capacity in the adjacent distribution network is used by developments in their early stages and provides a degree of certainty that major investment will not become stranded by a development failing to proceed.

This approach is facilitated by our Growth Servicing Strategy which identifies the status of plans to service all known brownfield and greenfield developments within the network area (refer to Attachment 5.21). The objective is to facilitate better communication and coordination with the development industry and government agencies regarding the availability of electricity distribution infrastructure.

While the network augmentation associated with the connection of new installations is generally arranged and funded by the connection proponent (as specified in our Network Connections Policy), these connections also result in increased capacity requirements in the upstream network. An annual process of forecasting demand, informed by an understanding of proposed developments gained from developers and planning authorities, and risk-based capacity planning to identify and manage resultant constraints on the network ensures that sufficient capacity is made available in a timely manner.

Sydney's growth centres at a glance

North-West Sydney

The North-West Growth Centre is approximately 10,000 hectares – the size of Wellington, New Zealand. It will have capacity for 70,000 new dwellings and 200,000 people.

It is made up of 16 'Precincts', which are areas which will be progressively released over the next 30 years. Six Precincts rezoned already with a further five undergoing Precinct Planning.

South-West Sydney

The South-West Growth Centre is approximately 17,000 hectares, comprising 18 precincts. It will be around the same size as Canberra.

It will focus on the major centre of Leppington, to be serviced by the South-West Rail Link. and has capacity for around 110,000 new dwellings.

Source: NSW Government Department of Infrastructure and Planning

Asset age and condition

Asset age and condition is key into our investment decisions and capital forecast. As outlined earlier in this chapter, we have undertaken a substantial replacement program throughout the current regulatory control period, with the main thrust of the program directed at transmission and zone substation equipment, much of which was impacted by mechanical issues, poor electricial integrity, corroded structures, oil leaks etc.

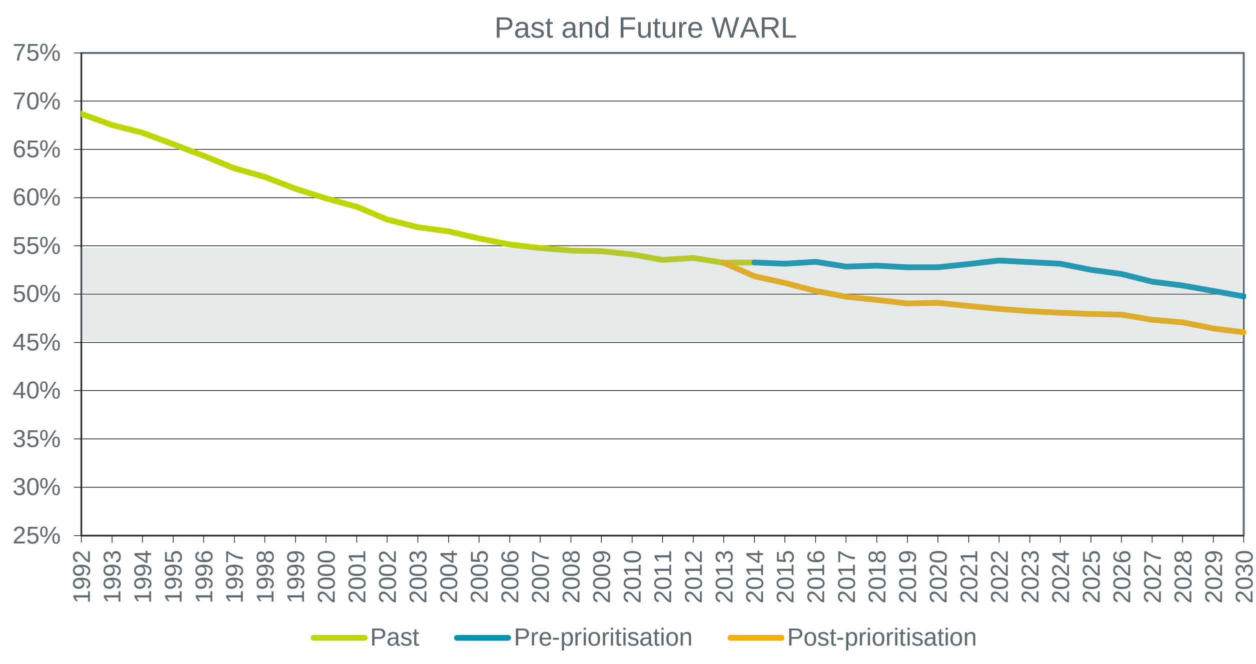
Our approach to asset renewal planning is strategic and sophisticated to ensure sustainable investment in the network. A range of approaches have been adopted for identifying assets that are candidates for renewal, ranging from simple inspection and condition-based maintenance regimes through to detailed technical analysis of key asset indicators. Average age modelling provides a useful high level check on the detailed condition-based assessment we undertake to develop our forecast. Network assets will generally be renewed before the point at which they fail or are unable to fulfil their performance requirements in a safe manner.

Allowing the average age of the network assets to deteriorate to unacceptable levels will result in service outcomes, including network safety and supply reliability, that do not meet customer needs. Conversely, a network that has an average age that is too young does not represent an efficient use of resources.

The weighted average remaining life (WARL) of the asset base measures the remaining life of the network assets, taking into account both age and condition issues. Endeavour Energy targets a WARL over the long term of 50% ± 5%, which is considered to represent a sustainable level of asset replacement expenditure that is appropriately balanced with the resultant network risk.

The level of expenditure necessary to achieve the targeted WARL is modelled from the current age profile of the network asset. The historic and projected WARL of Endeavour Energy's asset base is shown in Figure 18 below. In the forthcoming regulatory control period, Endeavour Energy's replacement expenditure has been cut following the risk-based prioritisation of programs in order to achieve the objective of reducing costs to our customers. This reduction in expenditure will result in an increase in the average age of the network assets with a subsequent reduction over time in the WARL of the assets and increased risk of asset failure. The effect of this has been modelled and is shown as the post-prioritisation line in the figure below. Although the WARL is forecast to reduce significantly, it will remain within the sustainable limit of 50% ± 5% noted above and the resultant network risk is considered to remain acceptable.

Figure 18: Weighted average remaining life of the network asset base



By proactively focusing on managing the average age of network assets, this strategy also seeks to achieve a more consistent and sustainable level of expenditure in the long term, rather than create a 'boom-bust' investment cycle. Our replacement program effectively balances the need to replace assets before they fail with the requirement to ensure the costs of doing so are efficient.

Reliability and security of supply

Network reliability and security of supply are driven by a number of factors including network age, design and configuration, historic capital expenditure levels and asset management practices as well as external influences on the network. To date, the focus of reliability improvement efforts has been on meeting DRP Licence Conditions and investing in a network that provides a high degree of resilience to environmental impacts.

Recent levels of capital investment have arrested the decline in the average age of the network and have eliminated some areas where historic design and configuration practices did not support the levels of reliability now expected by customers.

Community and government concern regarding the cost of electricity means that the strategic focus of efforts to improve reliability performance must be on improving the efficiency and effectiveness with which the network asset is operated, in order to gain performance improvement with reduced cost. A key driver of investment during the 2009-14 period was the supply security conditions contained in Schedule 1 of the DRP Licence Conditions. While meeting these conditions improved our network security and reliability, the removal of Schedule 1 of the DRP Licence Conditions alleviates investment pressures in this area.

Notwithstanding this, we will continue to focus on maintaining the current levels of reliability and security of supply. The importance of maintaining our performance in this area is reinforced by the introduction of the STPIS.

Service Target Performance Incentive Scheme (STPIS)

As discussed earlier in this proposal, the AER is introducing a STPIS in the next regulatory period, which will change the way in which reliability improvement initiatives are evaluated and managed. Improvements in reliability beyond the target set by the AER will result in increases in the allowed revenue in following years, while reductions in reliability will result in reductions in allowed revenue.

To reduce revenue and pricing volatility under a STPIS regime, Endeavour Energy considers that value for customers is maximised by sustainable, systematic reliability improvements rather than initiatives that focus on specific geographic areas of lower reliability. Endeavour Energy will maintain a focus on preserving reliability in a range around the current level, which is line with the STPIS target. Refer to Attachment 0.14 for an explanation of our proposed performance targets and level of revenue at risk.

Costing programs of works

We have largely used historical and current costs to determine the expected costs of completing works, and have modified this where appropriate to reflect site specific factors. Historical unit costs, current labour and contractor rates and materials and equipment costs have been used to develop the bottom-up forecasts. Indirect costs are allocated to capital expenditure projects according to our cost-allocation method approved by the AER.

We would ordinarily escalate our forecast costs to reflect the expected real change in costs over the 2014-19 regulatory period based on cost types (labour, contracted labour and materials). We have received real cost escalators for each cost type based on most recently available market data and economic analysis. We have applied the real labour escalators to our forecast capital expenditure. We have not applied material escalators as we will offset these via delivery efficiencies.

5 CAPITAL EXPENDITURE

Table 17: Real labour escalators for 2014-19

Real cost escalators (%)	2014-15	2015-16	2016-17	2017-18	2018-19
Labour - utility	1.2%	1.6%	2.1%	2.1%	2.0%
Labour - WPI prof. serv.	0.8%	1.3%	1.8%	1.9%	1.9%
Labour - WPI all	0.6%	1.1%	1.7%	1.8%	1.8%

These cost escalators are discussed in Attachments 0.04 and 0.05.

Delivering the programs of works

An important aspect of the network strategy is to ensure that the business has the capability to deliver the forecast capital program in an efficient and effective way. The importance of efficient program delivery is further elevated in the context of striving to keep our share of a customer's bill at or below CPI over the 2014-19 period.

In order to execute the proposed capital program, we have developed a Strategic Asset Management Plan (SAMP) Delivery Plan. The delivery plan identifies resource levels required to deliver the capital program in a way that ensures milestones will be achieved and the use of internal and external resources will be optimised. In particular, the SAMP Delivery Plan identifies specific critical resource shortages and the time period over which they apply, thereby informing resourcing targets.

A key feature of our delivery strategy for the next regulatory period focuses on optimising the mix of labour between internal and external resources. Through the use of the SAMP Delivery Plan, we will gain an understanding of the type and volume of work that needs to be externally resourced and be able to assess the market capacity to deliver this volume of work. We will aim to use external resources in instances where they are able to safely deliver the desired outcomes at least as cost-effectively as our own resources.

Prudent use of technology

In addition to our demand management, our business has been, and continues to evaluate operational technology solutions to network management problems for their applicability and cost effectiveness on the network. The focus of this strategy is to understand how a range of technologies that have proven their effectiveness in similar situations may be utilised on the network to add value in the future.

A more detailed description of our Network Technology Strategy and the projects proposed under the strategy for the 2014-19 period is provided at Attachment 5.32.

Demand management

When analysing emerging network constraints, the use of non-network alternatives, such as demand management, is an important aspect of optimising the available capacity in the network to meet forecast demand. The use of demand management techniques is generally designed to reduce the need for investment in network capacity by moving demand that occurs at peak times to times of lower overall demand.

Additionally, the NER requires us to investigate demand management options when planning major network upgrades by engaging in a thorough consultation process. This gives all interested parties the opportunity to submit ideas, and allows for cost-effective demand management and other system support options.

We have implemented many demand management programs over the past 16 years ranging from fuel substitution, industrial/commercial area permanent demand reduction and load curtailment, embedded generation and residential voluntary load curtailment programs. The changing environment has resulted in customers being more willing to participate and be involved in non-network alternatives as a viable alternative to additional network infrastructure.

5 CAPITAL EXPENDITURE

Our demand management strategy focuses on implementing non-network alternatives where trials of the intended systems or technology have proven their benefit and cost-effectiveness. The strategy, which has a proposed capital expenditure of $3.8 million and operating expenditure of $9.2 million for the 2014-19 regulatory period, comprises three components:

- Pilots and trials. During the 2014-19 period, our pilot programs are to be funded via the DMIA. The objective of these programs is to test technologies and concepts which will provide long-term network efficiency gains to energy users and reduce network costs. The focus will be on improving our understanding of the application of air-conditioning control, energy storage and power factor correction to residential customers.
- Targeted constraint driven initiatives. Over the 2014-19 period, our targeted programs involve business-as-usual approaches to implementing non-network options. These are programs that seek to reduce peak demand in order to remove a specific network limitation and defer network augmentation. The economic evaluation for these projects is based on the deferred value of the preferred network augmentation (avoided distribution cost).
- Broad-based initiatives. Demand management initiatives are also targeted more broadly to improve the utilisation of the network and extend the time before demand growth causes constraints to occur. The broad based initiatives that will be undertaken over the 2014-19 period focus on converting hot water systems and pool pumps to off-peak tariffs (controlled load) and installing power factor correction devices for commercial customers.

Additional information on our demand management strategy is contained in Attachment 5.34.

5 CAPITAL EXPENDITURE

Forecast capital expenditure program

For the 2014-19 regulatory period, our capital expenditure forecasts are primarily focused on meeting electricity demand from the North-West and South-West Sydney Growth Centres. We also have a substantial program aimed at replacing assets which are nearing the end of their useful lives.

The projects proposed over the next period will allow us to meet customer demand prudently and efficiently and ensure that our network continues to meet the statutory obligations in relation to reliability and security.

The table below summarises the capital expenditure forecasts required for our network for the 2014-19 regulatory period. These forecasts align with the objectives of our network strategy and have been prepared in accordance with our key assumptions, outlined above. Forecast capital expenditures have been allocated to standard control services in accordance with the approved Cost Allocation Method (CAM).

In preparing our capital expenditure forecasts, we have exposed each forecast to internal testing and external review to ensure they are efficient and prudent, and reflect a realistic expectation of the demand forecasts and cost inputs. This is important, not only to satisfy the requirements of the NER, but to ensure that each expenditure forecast is aligned with our network strategy. We also consider that the proposed level of network investment over the next five years will facilitate longer-term price stability and minimise the risk of future investment booms.

Table 18: Forecast capital expenditure over the 2014-19 regulatory period

$m; Real 13-14	Forecast year ending 30 June					
	2015	2016	2017	2018	2019	Total
Growth	119.9	92.8	62.3	77.1	77.2	**429.3**
Asset renewal/replacement	208.2	197.8	178.8	175.9	162.2	**922.8**
Reliability and quality of service enhancement	13.6	12.3	12.9	13.1	13.5	**65.3**
Compliance	30.0	18.2	23.5	23.1	21.0	**115.8**
Other system assets	6.9	7.3	7.5	7.3	7.5	**36.5**
Total system	378.6	328.4	285.0	296.4	281.3	**1,569.6**
Non-system assets	54.4	32.7	29.3	29.3	30.8	**176.4**
Total	**432.9**	**361.1**	**314.3**	**325.7**	**312.0**	**1,746.1**

System capital expenditure

System capital expenditure reflects our capital expenditure requirements for assets used to convey electricity through our network. We have four categories of system capital expenditure, as discussed below.

Growth (Augmentation)

We augment the network to connect new customers, and ensure that the capacity of the network is adequate to meet the forecast demand. Additional capacity is installed to provide back up supply in the event of faults where the risk of non-supply is considered to justify the cost associated with the additional capacity. There are two key drivers of investment:

- New customer connection. This includes connection of new customers to the network which necessitates augmentation of the shared network in existing network areas.
- Reinforcement. Where the aggregate demand from new and existing customers in an area necessitates augmentation of the shared network (either at the distribution system and/or sub-transmission system level).

Over the 2014-19 period, AEMO forecasts state average growth of 1% per annum in peak demand. Our forecast growth in peak demand of 0.2% per annum is below the AEMO forecast when significant developments and other known load additions are excluded. Our forecast is however, increased to 1.8% per annum when we account for the significant localised growth in Sydney's North-West and South-West growth sectors.

This means that the key driver of growth-related investment for the 2014-19 period is the need to provide infrastructure to service the greenfield developments in Sydney's North-West and South-West growth sectors.

Asset renewal/replacement

We invest in the renewal and replacement of assets when the condition of the asset indicates that the continued safe and reliable operation of the existing asset is no longer economically viable. There are a number of regulatory obligations that drive our investment including public safety, workplace safety and environmental legislation. The key drivers of investment are:

- degradation in the condition of assets on the network, generally as a result of the asset's age, condition and environmental factors
- safety, environmental or other asset-related risks.

We have modelled our forecast renewal/replacement expenditure using the AER's REPEX model. At a "whole of network" level the model forecasts average expenditure on asset renewal of $241 million per year over the 2014-19 period. This contrasts with average expenditure proposed in this submission of $185 million per year. As discussed previously, this level of expenditure will result in the average age of the network asset increasing however it is considered that this is likely to be the minimum level of expenditure that is sustainable in the long term and avoids a "boom-bust" cycle of investment.

Reliability

We invest to ensure compliance with reliability performance targets set out in jurisdictional licence conditions, and in particular ensure that customers connected to the worst-performing parts of the network receive at least the minimum specified levels of reliability. The main driver of investment in this capital expenditure category is our performance against DRP Licence Condition reliability targets.

Reliability focused projects included in our expenditure forecast are considered in the context of the AER's STPIS scheme. The STPIS scheme offers the company financial incentives or penalties based on improvement or deterioration in performance from the target set at the start of the regulatory period. Endeavour Energy's reliability plan is to stabilise and maintain reliability performance at levels that will avoid incurring penalties under the STPIS scheme.

Reliability performance investigations that underpin this aspect of our expenditure forecast often result in a number of options to improve performance. A cost benefit analysis based on the STPIS scheme is undertaken to select the lowest cost option which both delivers an acceptable reliability improvement and a positive STPIS benefit. Endeavour does not seek to unnecessarily maximise STPIS returns recognising that although customers benefit by receiving improved reliability, STPIS incentives result in increased cost to customers for improved reliability. Our customer engagment activities indicate that customers are not willing to fund improvements to reliability and are satisfied with current levels of performance.

Compliance

A number of regulatory obligations drive our investment. They include public safety, workplace safety and environmental legislation. Our forecast is to spend $116 million on compliance for the 2014-19 control period.

For a listing and anticipated cost of some of the major projects that make up these programs, refer to Table 5.1 of the Reset Regulatory Information Notice (RIN)[50] and a number of key project business cases we have attached to this proposal. The material assets listed in RIN template 5.1 support the provision of standard control services.

Non-system capital expenditure

The non-system capital expenditure category includes expenditure which supports the operation of the regulated network system (not directly related to the construction or replacement of system assets). This expenditure is required to safely and reliably service our asset base and deliver the outcomes defined in our network strategy. Refer to our Reset RIN templates and schedule 1 response for further details on these costs.

Our non-system capital expenditure relates primarily to land and buildings, vehicles, furniture and fittings, plant and equipment and information and communications technology (ICT), and is shown in Table 19.

Table 19: Proposed non-system capital expenditure for 2014-19

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
ICT	16.0	15.3	16.5	19.2	15.6	**82.5**
Motor vehicles	5.2	4.7	5.1	3.0	8.1	**26.1**
Land and buildings	29.2	8.8	3.8	3.2	3.2	**48.2**
Furniture, fittings, plant and equipment	4.0	3.9	3.9	3.9	3.9	**19.6**

ICT

The primary role of the ICT function within Endeavour Energy is to ensure the reliability, performance and security of technology systems, data and end point devices. ICT provides critical business support to meet our obligations as a DNSP. Without technology, we would not be able to operate the current network, undertake effective planning of the network or fulfil our corporate obligations. Technology provides the following core capabilities:

- ICT systems are instrumental in delivering our network and corporate functions such as asset management, customer management, and financial reporting
- prudently adopting technology enables us to deliver better services to our customers at a lower cost over time
- technology is viewed as a strategic enabler that supports business objectives.

Endeavour Energy's ICT regulatory proposal includes a total capital expenditure of $82.5 million.[51] Endeavour Energy's proposed capital expenditure represents a reduction of approximately 34% from the current AER determination of $124.8 million (real, $13-14). This represents a 5% decrease on actual capital expenditure from the current determination period.

[50] As required by S6.1.1(1)(iii)-(v) of the NER.

[51] Adjusted to reflect Regulated Capital expenditure to align to AER allowance calculation.

5 CAPITAL EXPENDITURE

The proposed ICT capital expenditure is required to achieve Endeavour Energy's ICT Investment Plan. Each plan item identifies the strategic objectives and the business drivers from which potential ICT projects have been identified and prioritised. The rationale for this approach is to maximise technology investment and directly contribute to the attainment of strategic and operational goals. The following chart summarises the high level goals and associated major programs of Endeavour Energy's ICT Investment Plan.

Refer to Attachment 0.09 for Endeavour Energy's ICT investment plan. We engaged KPMG to conduct an extensive review of our plan and forecast capital expenditure. This includes benchmarking our expenditure against other Australian NSPs, for which we perform above average. Refer to Attachment 5.31 for KPMG's full report.

Purpose	**LEVERAGE TECHNOLOGY Using technology to deliver business outcomes in the most effective and efficient way**					
Key investment area	**Safety management**	**Deliver the network plan**	**Network billing and customer management**	**Finance and risk management**	**Performance through people**	**ICT service delivery**
GOALS	Invest in technology to educate, monitor and measure the achievement of safety objectives.	Invest in technology to create processes to allow management of reliability and greater use of smart grid technology to achieve lower capital and operating cost accounts	Manage/replace legacy systems to support the high data volume processes and strict deadlines for delivery where non-compliance or lack of data accuracy and transparency may result in financial penalties and revenue loss for Endeavour Energy.	Invest in technology to facilitate sound commercial decisions, drive sustainability of operations and performance and to ensure risks, costs and prices are controlled and maintain a high level of compliance.	Automate manual processes, integrate data and systems for process performance improvement and enhanced performance reporting to increase our ability to respond to future requirements of the organisation.	Provide an assured business platform and support the delivery of corporate objectives cost effectively.
MAJOR PROGRAMS	***Mandatory/ Regulatory*** Fatigue management ***Assured business operations*** Safety training Safety systems enhancements Safety systems technical currency program	***Assured business operations*** Technical Currency Program ***Improve the business*** Process automation and mobile crews ***Strategic Initiatives*** Network asset management	***Mandatory/ Regulatory*** Customer management compliance ***Assured business operations*** Network billing Technical Currency Program	***Assured business operations*** Business Risk Technical Currency Program Decision Support Program Records Management Upgrade and Digitalisation Program ***Improve the business*** Finance Automation Program	***Assured business operations*** Employee portal improvements LMS – process enhancements ***Improve the business*** HR workflow, automation and collaboration Improvements to automation of timesheets	***Assured business operations*** IT infrastructure asset management and services IT Communications asset management and services ICT operational services Information security

Endeavour Energy

5 CAPITAL EXPENDITURE

Fleet

Endeavour Energy's $26.1 million motor vehicle capital expenditure program is directly related to the expected number of staff employed, particularly in field-based roles, which have the highest use of light commercial vehicles, trucks and plant. Endeavour Energy's forecast fleet expenditure over the 2014-19 regulatory period primarily comprises replacement expenditure for existing fleet, which is driven by our documented vehicle replacement policies.

Endeavour Energy is prioritising the reduction of investment in its fleet by increasing utilisation and better sharing of fleet assets, thus achieving a reduction in overall fleet numbers.

Land and buildings

Endeavour Energy's $48.2 million land and buildings capital expenditure program is a result of renewal and compliance-based drivers. We must accommodate the required number of personnel required to support the forecast program and the associated ongoing maintenance and operational requirements.

Endeavour Energy continues to meet its compliance requirements and community expectations regarding safe and environmentally sound work practices. Meeting these requirements necessitates expenditure on both new and existing facilities.

Major land and buildings projects include:

- construction of a new Field Service Centre (FSC) at Guildford to service the Holroyd area
- upgrade of HVAC systems in the Huntingwood Head Office
- construction of a new FSC at Mulgrave to replace the existing South Windsor FSC
- stage 3 of the current re-development of the existing Springhill FSC.

Furniture, fittings, plant and equipment

Endeavour Energy's $19.6 million furniture, fittings, plant and equipment capital program is made up primarily of capitalised tools and equipment which support the network construction and maintenance programs. It also includes the furniture and fittings component of the land and buildings program.

5 CAPITAL EXPENDITURE

Meeting the Rules

Our forecast is aligned to the objectives and principles in the NER. Our processes are demonstrably prudent and result in efficient costs. We have provided supporting information relating to meeting the Rules in our proposal.

The Rules require the AER to make a decision on whether to accept or reject our total forecast capital expenditure. The AER must accept the total capital expenditure forecast if it is satisfied that the total meets the capital expenditure criteria, having regard to the capital expenditure objectives and factors. The overall objective of the framework is to ensure that forecast capital expenditure is sufficient to comply with relevant reliability and safety standards at an efficient cost in the long term.

To enable the AER to make its decision, the Rules require Endeavour Energy to comply with specific information requirements in Clause 6.5.7 and Schedule 6.1.1 of the Rules. This includes an obligation to comply with the requirements of any relevant regulatory information instrument.

In regards to the RIN, Endeavour Energy has undertaken a comparison of the high level requirements contained in the Expenditure Forecast Assessment Guideline against the specific requirements in the RIN. All matters covered by the Guideline are addressed by the RIN requirements which have been customised to reflect Endeavour Energy's business. Accordingly, Endeavour Energy's RIN response meets the requirements of the Guideline as required by the AER's F&A paper.

In the sections below we briefly identify how we have met the capex objectives, criteria and factors in Attachment 0.03.

Meeting the capital expenditure objectives

The Rules states that Endeavour Energy's forecast capex must be the expenditure that Endeavour Energy considers is needed to achieve each of the outcomes listed in clause 6.5.7(a), known as the 'capital expenditure objectives' (capex objectives). These objectives are:[52]

- meet or manage the expected demand for standard control services (objective 1)
- comply with all applicable regulatory obligations or requirements (objective 2)
- maintain the quality, reliability and security of supply of standard control services and of the distribution system through the supply of standard control services (objective 3)
- maintain the safety of the distribution system through the supply of standard control services (objective 4).

Our capital plans relate to one or more of the 4 capex objectives in the Rules. Our network capital plans relate to investments we require to comply with our regulatory obligations as a DNSP to provide safe and reliable electricity services. In the summary below we show how each of our capital plans relate to one or more objectives.

[52] See clause 6.5.6(a) for exact wording.

5 CAPITAL EXPENDITURE

Capital plan	Capex objectives achieved
Transmission Network Planning Review	1 and 3
Strategic Asset Renewal Plan	2,3 and 4
Distribution Works Program	All
Reliability Works Program	2 and 3
Strategic Asset Management Plan	All
Technology Plan	All
Corporate Property Plan	All
Fleet and Other Support plan	All

Allocation of forecast capital expenditure in accordance with the Cost Allocation Method

Further, Endeavour Energy has ensured that the total forecast capital expenditure in our building block proposal only relates to standard control services by excluding costs that relate to unclassified services and alternative control services. The forecast capital expenditure set out and explained in this chapter is expenditure that is properly allocated to standard control services in accordance with the CAM approved by the AER on 2 May 2014.

Broadly, we disaggregate costs in accordance with the AER's service classification and then further allocate costs by organisational unit, activity, sub-activity and expense element. We undertake cross checks through the management assurance process and the independent assurances processes to certify that the value of costs reported at the total level is equivalent to the sum of costs reported at the lowest level of classification.

The approved CAM can be found at Attachment 0.07.

Meeting the capital expenditure criteria

The AER must accept Endeavour Energy's forecast of required capex if it is satisfied that the total forecast capital expenditure reasonably reflects each of the criteria, being:

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

In making this decision, the AER must have regard to the capex factors as well as the information included in or accompanying Endeavour Energy's regulatory proposal, written submissions and any analysis undertaken by or for the AER.[53]

At the time of our 2009-14 regulatory proposal, we engaged NERA to provide expert economic advice on the interpretation of the expenditure criteria and on how to demonstrate that our forecast expenditure reasonably reflects these criteria. In 2014, we engaged NERA to provide an updated view on its initial report in light of changes to the Rules for economic regulation. NERA's advice is at Attachment 0.13.

[53] Clauses 6.10.1(b) and 6.11.1(b) of the Rules.

5 CAPITAL EXPENDITURE

An important element of NERA's advice was that there are no directly observable measures of efficiency. NERA considered that a practical demonstration that the forecast expenditure reasonably reflects the expenditure criteria can be achieved by:

- demonstrating that the process the DNSP employed in developing its forecast expenditure is efficient and prudent. In this respect a number of the capex factors relate to the process used by the DNSP
- using indicators to assess the reasonableness of the result and to inform a decision on whether the resulting forecast expenditure (from applying a prudent forecasting approach) reasonably reflects the efficient cost. In this respect, a number of the capex factors represent partial checks of the forecast.

Meeting the capital expenditure factors

Forecast process

Our expenditure forecasting process is based on meeting our regulatory obligations, and draws on our expert understanding of our network and the functions we have to perform in our role as a DNSP. In terms of demonstrating that our forecasting process is efficient and prudent, we have provided evidence in Attachment 0.03 to show that:

- we have effective policies and procedures to inform our expenditure decisions and our planning processes
- our governance processes ensure that expenditure decisions are appropriately delegated and have effective financial controls
- we have used a fit for purpose forecasting method which ensures there is no overlap or gap in our expenditure requirements, and uses appropriate methods for identifying investment on different parts of our network and network elements
- we have a consistent and appropriate method for identifying investment need that takes into account our circumstances, and a rigorous approach for selecting of the most efficient option to address the need.

A key element of our forecasts process is the use of realistic expectation of the demand forecasts and costs inputs, consistent with the capex criteria in the NER. Endeavour Energy's planning process has incorporated accurate and up to date peak demand forecasts as part of the key inputs into developing capital plans. Endeavour Energy records peak demand at each of its 159 zone areas, and this provides an indication of trends in demand growth at different points in the network. Importantly, Endeavour Energy's forecast process is capable of excluding spot loads from trend growth, considering new connections in the short term, and weather correcting.

In terms of cost estimates, we have used 'fit for purpose' methodologies to derive the costs of undertaking projects or programs of work in each capital plan. Our methodologies take into account historical experience, the specific nature of the program of work, and potential efficiencies that may arise. Our cost estimates have also taken into account expert opinion from economic forecasters on real cost escalation over the 2014-19 period.

In Attachment 0.03 we have also addressed the capex factors in the NER that specifically relate to the forecasting process used by a DNSP. In summary:

- we have considered the substitution possibilities between operating and capital expenditure in developing our forecast expenditure (capex factor 7). A key step in our expenditure forecast process is to consider the full range of alternative options, including areas where there may be opex solutions. Refer to section 5.5, 'substitution possibilities between operating and capital expenditure (expenditure factor 7)' of Attachment 0.03 for further details. Additionally, refer to Attachments 6.04, 6.05 and 6.08 for our capitalisation policies.
- Endeavour Energy has considered and made provision for efficient and prudent non-network alternatives (capex factor 10). We have investigated ways to defer augmentation at specific sites of

our network when developing our forecasts and have incorporated the expected reduction in system demand from the implementation of new broad based demand management activities. The savings from demand management initiatives have been incorporated into our capex forecasts.

- we have considered the relative prices of operating and capital inputs (capex factor 6). As noted above we have sought to assess all feasible options when addressing a need including opex and capex options. When doing so, we have used best practice methods for deriving the relative cost of opex and capex solutions, and have applied a common method for real cost escalation.
- our forecast process has considered the concerns of electricity consumers as identified in the course of our engagement with electricity consumers (capex factor 5A). We engaged customers on a range of issues including reliability, price, and demand management. The findings from our customer engagement support the basis of our proposed total capex including in relation to price affordability, and maintaining current levels of safety and reliability.
- Endeavour Energy's forecast method considered whether any projects or programs of expenditure should be identified as contingent projects, and therefore excluded from the total forecast capex for standard control services (capex factor 9). We found that no project met the criteria of a contingent projects set out in 6.6A.1 of the Rules.
- our forecast process identified that there have been no final project assessment reports at the time of submitting this proposal. (capex factor 11).

Indicators to assess the reasonableness of the forecast

Whilst there is no external, observable measure that can be relied upon to demonstrate that the total forecast expenditure is efficient, there are nevertheless partial indicators that assist in confirming the efficient level of the forecast expenditure that was derived from a prudent approach. These factors are stated in the NER and are intended to assist the AER in making a decision on whether the total forecast expenditure reasonably reflects the expenditure criteria.

In Attachment 0.03 we have addressed the remaining capex factors that we consider may represent partial indicators of the efficient level of capex. In relation to actual and expected capital during any preceding regulatory control periods (capex factor 5), we consider there are two primary considerations that provide a partial check on the total forecast proposed:

- we have identified key variations to forecast capex in the 2009-14 period, and consider that these have been taken into account when developing forecasts in the next period. For example, we consider that lower demand than forecast was a key driver of reduced capex, and that our demand forecast process has improved in preparing our 2014-19 forecasts.
- our forecast capex for 2014-19 is substantially less than the 2009-14 period, and can be explained by key changes in our circumstances. In particular the lower capex has incorporated the efficiencies we have sought to achieve to make prices more affordable for our customers. While capex is lower in the 2014-19 period, we note that replacement is still required to maintain the safety of our network, and that capacity investment relates to localised spot loads on our network.

We note that previous expenditure analysis should be viewed in conjunction with whether the forecast is consistent with any incentive scheme that apply to the DNSP (capex factor 8). Under the ex ante incentive regime applied to capex in the 2009-14 period, Endeavour Energy had strong incentives to prudently and efficiently reduce capex relative to the AER's allowance. Endeavour Energy's actual capex in the 2009-14 period was considerably lower than forecast. In this respect, customers will benefit from reductions to the RAB which lowered prices when transitioning to the new period.[54]

[54] The benefits of reductions in capex has been shared with the customer through a lower value in the regulatory asset base when transitioning to the next regulatory period.

5 CAPITAL EXPENDITURE

The incentive regime has played a complementary role in the speed of our reform process, including re-orientation of strategies and planning processes towards meeting our goal of customer affordability. In this way, we consider that the AER can place weight on the efficiency of the forecasts for the 2014-19 period, providing a partial indication on the efficiency of our total capex.

The AER must also consider the most recent annual benchmarking report and the benchmark capital/operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period (capex factor 4). The purpose of this factor is for the AER to consider whether available benchmarking information can provide a partial indicator of the efficiency of the forecast expenditure, and if so the investigations and weight that should be ascribed to that data. The AER will be releasing its first benchmarking report in September 2014, and therefore we are not provided with an opportunity to demonstrate or make representations on this report at the time of submitting our regulatory proposal.

Endeavour Energy has developed a comprehensive report, Attachment 0.12. The report examines the inherent limitations of benchmarking Australian DNSPs, and the role that benchmarking should play as a partial indicator of efficiency. Our analysis identified that benchmarking has inherent limitations such as inability to conduct ‘like for like’ analysis across peer firms, data inconsistency and inaccuracy, and failure to meet statistic principles. We think that appropriate benchmarking does have a role in guiding the regulator to areas requiring further granular analysis. It should not be used to reject a DNSP’s proposal, or as a basis to substitute the forecast given the inherent limitations as a tool. In the report we also:

- assessed the relative weight that should be applied to each of the benchmarking tools identified by the AER in its Forecast Expenditure Assessment Guidelines including economic analysis, aggregated category analysis, and cost category data including the augex and repex models. When deciding if a benchmark is appropriate, we have been guided by the Productivity Commission’s review in 2013 which set out six criteria for when a benchmarking tool could be used in the process.
- sought to understand the available data that can be used for benchmarking and reported on these outcomes. This was based on a Huegin Consulting study of seven DNSPs in Australia. The Huegin study demonstrates that benchmarking is of limited value due to its inherent limitations, and that measures of efficiency more closely relate to the characteristics of the business rather than managerial decisions. Despite this, Huegin’s report does provide some basis to show that Endeavour Energy is relatively efficient. Refer to Attachment 0.11.
- we have assessed the relative merits of the repex and augex model that the AER have developed. Our analysis of the models suggest that the models fail to meet the criteria of the Productivity Commission, and should be used with extreme caution. In the case of the augex model, we consider it to be highly flawed as an indicator of the efficiency of our capacity investments. The repex model should only be used for limited asset classes, where it can be demonstrated that it is fit for purpose. Even in these cases, we think the model is very limited and should only be used to assist the AER to target its detailed review of business cases.

Based on this approach, we have placed limited weight on benchmarking analysis as a valid test of the efficiency of our forecast and consider that the AER should do likewise in its assessment. Our analysis of benchmarking tools suggests that trends in a DNSP’s results over time is of more value than relative efficiencies between DNSPs at a point in time.

The final factor we have considered as a partial indicator of efficiency is the extent the operating expenditure forecast is referable to arrangements with another person that do not reflect arm’s length terms (capex factor 9). We confirm that our forecast capex for 2014-19 does not include any arrangement with any other person that do not reflect arm’s length terms.

6 OPERATING EXPENDITURE

Summary

We are proposing $1.4 billion (real 2013-14) of operating expenditure for the 2014-19 period to support our business activities and maintain the reliability, safety and security of our distribution system. Our ongoing focus on achieving efficiencies has resulted in a real decrease in operating expenditure relative to the 2009-14 regulatory period allowance.

This chapter outlines the forecasting method and underlying assumptions underpinning our proposed operating expenditure program for the 2014-19 period. The forecast operating expenditure is the efficient cost of meeting the operating expenditure objectives[55] and is shown in Table 20 below.

Table 20: Forecast standard control operating expenditure over the 2014-19 regulatory control period

	Forecast year ending 30 June					
$m; Real 13-14	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**TOTAL**
Total operating expenditure	267.6	272.4	281.2	278.7	284.4	**1,384.3**

A number of efficiency programs were developed and implemented within the 2009-14 period that continue into the 2014-19 regulatory period to ensure we deliver our services at the lowest cost to customers. In developing our forecast, we have sought to balance stakeholder expectations and the following needs:

- ensure we meet our obligations to operate a safe, reliable and sustainable network and to keep our workplace free from harm
- meet all our legislative and regulatory obligations, current and expected
- contain our share of the customer's bill to at or below CPI.

These overarching goals are consistent with the operating expenditure objectives specified in the NER, which are:

- meet or manage expected demand for standard control services
- comply with all applicable regulatory obligations or requirements
- maintain the quality, reliability and security of supply of standard control services
- maintain the reliability, safety and security of the distribution system through the supply of standard control services.

In line with the AER's approach to revenue regulation, the proposed operating expenditure program includes allowances for self-insurance premiums, and debt and equity raising costs associated with the proposed capital program.

The NER requires Endeavour Energy to provide details and information on various aspects of our forecast operating expenditure. This includes compliance with the RIN issued by the AER on 7 March 2014. We have addressed these requirements in this chapter and attachments, which together constitute our forecast operating expenditure regulatory proposal.

[55] Cl 6.5.6(a) of the NER.

6 OPERATING EXPENDITURE

Our performance in the 2009-14 period

As we forecast our costs using the base step trend approach it is important to discuss the outcomes of the previous regulatory period. In this section, we demonstrate the efficiency of our base year and explain any variances between our actual and allowed expenditure.

Outcomes from last period

In the 2009-14 regulatory period we have significantly invested in our network to reduce safety risk and ensure our network was operating to the standard required under our licence conditions. This was achieved well within the operating expenditure allowances set by the AER. These savings were primarily driven by productivity based initiatives and the introduction of the Network Reform Program.

This section identifies the internal efficiency and productivity programs and the Networks NSW cost-reduction initiatives that have delivered substantial savings during the 2009-14 regulatory period.

We expect to achieve savings totalling an estimated $185 million over the 2009-14 regulatory period and our forecast operating expenditure maintains this efficient level of expenditure into the 2014-19 regulatory period.

The savings we have achieved in the current regulatory period are in excess of the annual reduction of 2% of labour operating expenditure we committed to making in our initial regulatory proposal in 2008. This achievement is a direct result of our collective efforts to find cost savings, improve productivity and realise efficiencies.

Table 21 below illustrates the actual and expected controllable operating expenditure for the current period compared to the approved AER allowance.[56]

AER reasons for NSW decision

"Each business plans to significantly increase its capital investment over the next five years. The AER's analysis confirms the need for, and efficiency of, an increased investment allowance, cognisant that this increased investment will result in higher user charges".

AER, News Release 05/09, 30 April 2009

Table 21: Actual and forecast expenditure compared to the 2009-14 regulatory allowance

$m; Real 13-14	2009-10	2010-11	2011-12	2012-13	2013-14	TOTAL
Allowance[57]	337.1	339.6	344.5	348.7	347.1	**1,717.0**
Actual/forecast[58]	282.3	297.3	303.8	276.4	320.5	**1,480.3**
Difference	(54.7)	(42.3)	(40.7)	(72.3)	(26.7)	**(236.8)**
% Variance	(16%)	(12%)	(12%)	(21%)	(8%)	**(14%)**

[56] In accordance with NER S6.1.2(7), operating expenditure for each of the past regulatory years of the previous and current regulatory control period is provided at Attachment 6.14.
[57] This allowance excludes amounts relating to the retail pass-through event, DMIA and debt raising costs
[58] For comparison, this actual expenditure excludes amounts relating to the retail pass-through event, DMIA and debt raising costs

6 OPERATING EXPENDITURE

As evident in the table our operating expenditure was consistently below the AER's allowance for the 2009-14 period. The drivers of this lower actual expenditure are in the table over the page and summarised in more detail in the following section.

Table 22: Drivers of the 2009-14 expenditure variances

$m; Real 13-14	2009-10	2010-11	2011-12	2012-13	2013-14	TOTAL
Cost reduction areas	(9.5)	(21.9)	(45.2)	(51.0)	(57.6)	**(185.2)**
Retail dis-synergy costs	-	3.4	13.8	12.5	13.4	**43.1**
Employee entitlements/ Superannuation	7.0	3.1	29.1	(7.2)	1.5	**33.5**
Vegetation management	(27.8)	(31.5)	(34.1)	(31.7)	(11.5)	**(136.5)**
Other	(24.5)	4.6	(4.3)	5.0	27.5	**8.4**
Over/(under)	**(54.7)**	**(42.3)**	**(40.7)**	**(72.3)**	**(26.7)**	**236.8)**

Variations in operating expenditure for 2009-14

Since the AER's 2009-14 determination, the landscape of the NSW electricity industry has changed significantly. At the time of the 2009-14 determination substantial investment was required to address a historical under-investment under the previous regulatory regime and to provide for forecast energy consumption and peak demand growth. This peak investment period resulted in price increases. We recognise the impact of this on customers and there is now a concerted focus to alleviate the network price pressures for customers.

The operating expenditure outcomes for the first four years of this current period reflect our focus on:

- Achieving an improved operating expenditure result compared to the efficient allowance set by the AER through operational improvement and efficiency projects, specifically the C7 Program, Project Challenge and Project Compete, which are discussed in more detail over the page.
- Implementation of the Network Reform Program to achieve further efficiency savings across our business while continuing to maintain the reliability and sustainability of the network without compromising the safety of the public or our employees. Further detail on the Network Reform Program is outlined over the page.

The actual and projected savings for the current regulatory period are shown in Table 23 over the page.

6 OPERATING EXPENDITURE

Table 23: Actual and forecast savings for cost reduction programs

$m: Real 13-14	2009-10	2010-11	2011-12	2012-13	2013-14	TOTAL
C7 program	9.5	21.9	34.3	27.3	26.8	**119.9**
Project Challenge[59]	-	-	9.2	19.4	21.7	**50.2**
Project Compete	-	-	1.7	4.1	6.2	**12.0**
Network Reform Program	-	-	-	0.1	2.9	**3.1**
Total cost reduction areas	**9.5**	**21.9**	**45.2**	**51.0**	**57.6**	**185.2**

With the introduction of the Network Reform Program in late 2012-13 in addition to the established cost-reduction programs of Projects Challenge and Compete, our expected operating expenditure for the final year of the 2009-14 regulatory period is expected to be 8% lower than the efficient amount set by the AER for the same period.

Further details of our cost-reduction programs are provided in the section below and in Attachments 6.01 and 6.02.

> ***Aim of reform***
>
> *"To help contain the rising costs of delivering electricity, the NSW Government will merge the three distribution networks into a single corporate structure to reduce waste and duplication and generate savings from economies of scale."*
>
> NSW Trade and Investment

Projects Challenge and Compete

Projects Challenge and Compete reflect our goal of continuously seeking efficiency savings and to maintain our share of the customer's bill at or below CPI over the next five years.

Project Challenge and Project Compete were part of our strategic priority actions from 2011-12. The objective of Project Challenge was to reduce our corporate and administration overheads by $22 million per annum (operating expenditure) without compromising the sustainability of our business. Project Compete was implemented to reduce the real cost of operating our regional and network operations by $26 million per annum (operating expenditure) without compromising safety, reliability or network sustainability. These efficiency programs were also designed to assist in offsetting the dis-synergy costs arising from the sale of our retail business in March 2011.

The savings identified from Projects Challenge and Compete are included in our efficent historical base for the 2014-19 regulatory period as these productivity improvements continue into the future. It is expected that the NSW Network Reform Program (NRP) will drive further savings in the next regulatory control period.

Network Reform Program (NRP)

In 2012 the NSW Government announced the Network Reform Program of the electricity distribution networks in NSW. The three network distribution businesses – Ausgrid, Endeavour Energy and Essential Energy – now operate as separate network businesses under a single operating model (Networks NSW). On 3 June 2013, an amendment to the Electricity Supply Act 1995 (NSW) was enacted that created a single Board to be the joint Board of Ausgrid, Endeavour Energy and Essential Energy.

[59] Projects Challenge and Compete are annualised ongoing savings year on year.

6 OPERATING EXPENDITURE

Network Reform Program is driving considerable change to the way the NSW electricity distribution industry operates and will deliver a more efficient, lower-cost electricity distribution service to customers that is financially sustainable, eliminates unnecessary waste, and maintains the reliability and sustainability of the network in a way that is safe for employees and the public. The reforms were designed to deliver significant savings to help reduce electricity prices and fund electricity rebates for NSW families.

The majority of the savings from the Network Reform are capital in nature. However, savings to operating expenditure of $40.3 million (real, 2013-14) for the 2014-19 regulatory period are expected from the implementation of Network Reform and are incorporated into the forecast operating expenditure requirement.

For a more detailed explanation of the Network Reform Program and the savings delivered across the Networks NSW businesses refer to Attachment 0.02.

NRP savings can be grouped into four categories:

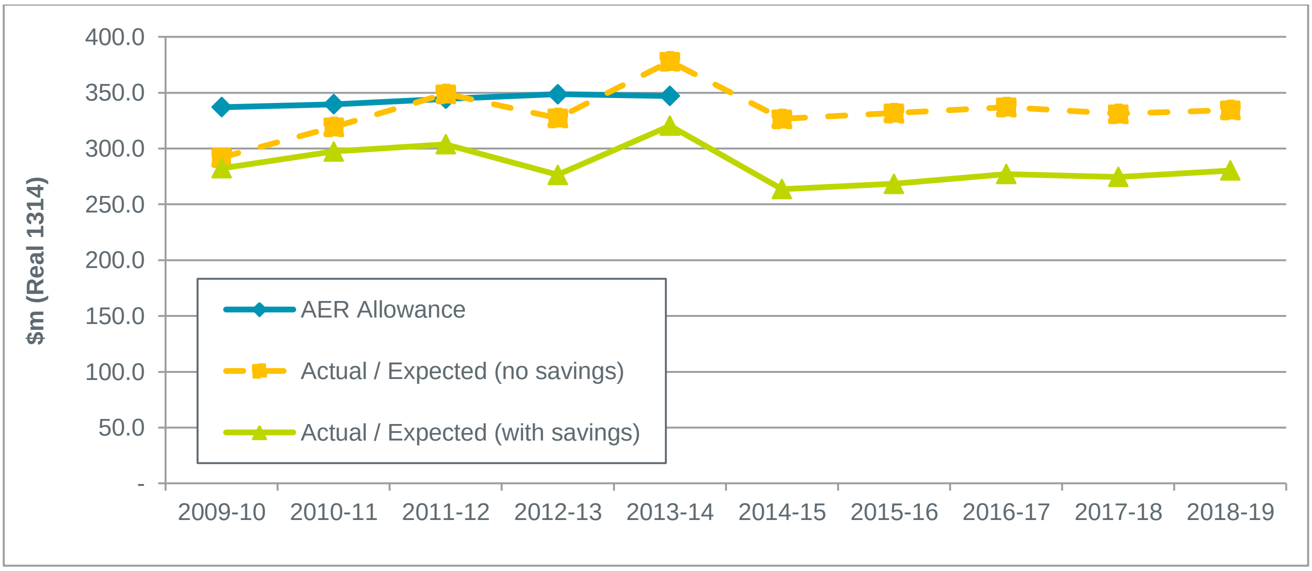
1. New Operating Model initiatives;
2. Strategy and Policy initiatives;
3. Capital expenditure Efficiency initiatives; and
4. Procurement and Logistic Initiatives

Impact of our efficiency programs and reforms

Figure 19 below sets out the AER approved operating expenditure allowance for 2009-14 exclusive of our commitment to achieve a 2% annual improvement in labour efficiencies over the same period. This has then been trended forward into the 2014-19 period and compared with our actual and forecast operating expenditure over the two regulatory periods 2009-19 to demonstrate the impact of our various efficiency programs. The underlying operating expenditure depicted in Figure 19 is our proposed operating expenditure for the 2014-19 period.

The key observation from Figure 19 is that Endeavour Energy has succeeded in maintaining operating expenditure reductions despite increases of costs from the reallocation of corporate costs and increases in vegetation management costs.

Figure 19: Actual and forecast expenditure compared to the 2009-14 regulatory allowance



Sale of Integral Energy retail business

Prior to 1 March 2011, Endeavour Energy[60] was an integrated business providing both distribution services (as a distribution network service provider or DNSP) and non-distribution services (including a retail business). Endeavour Energy provided these services using integrated systems and processes while maintaining ring-fencing arrangements.

Integral Energy (the retail business) was sold to Origin Energy on 1 March 2011. This involved the sale of the Integral Energy brand, Integral Energy retail customers and Integral Energy wholesale contracts to Origin Energy. Under the terms of the sale, Transitional Service Agreements (TSA) were agreed between Endeavour Energy and Origin Energy and ceased on 30 April 2013. The transition of the customer data and relevant services to Origin Energy for the retail business was completed at the end of January 2013.

As a result of terminating the TSA, the cost of providing standard control services increased due to the loss of integrated business synergies. An example of the loss of synergies relates to the cost of maintaining and supporting Endeavour Energy's network billing system (Banner).

Table 24: Retail dis-synergy costs in the 2009-14 period

$m; Real 13-14	2009-10	2010-11	2011-12	2012-13	2013-14	TOTAL
Retail Dis-synergy costs	-	3.4	13.8	12.5	13.4	**43.1**

Our Project Challenge and Project Compete efficiency programs sought to, and did, offset these dis-synergy costs.

The sale of the Integral Energy retail business to Origin Energy triggered a 'Retail Project' pass-through event as defined in the 2009-14 AER determination. The inclusion of this nominated pass-through event recognised that the retail activities of the three NSW DNSPs provided scale and scope efficiencies. In the absence of these retail businesses a greater portion of our efficient corporate costs would be allocated to our standard control services by operation of the approved Cost Allocation Method (CAM), to the level of efficient costs for a stand alone network business.

The AER concluded in the pass-through application decision made in March 2012 that:

> *The AER considers the sale of Endeavour Energy's retail business to Origin Energy materially increases the costs to the service provider of providing direct control services. As such, the AER considers that a positive change event has occurred in respect of Endeavour Energy's retail project event pass through application.*

It is worth noting that despite the known financial impact, Endeavour Energy did not seek to adjust its recovered revenues as a result of the sale.

These 'loss of synergy' costs have been factored into the forecast operating expenditure for the 2014-19 period recognising that the impact has been offset by our efficiency programs as stated above.

Employee entitlements/Superannuation adjustments

Endeavour Energy is required to set aside amounts for liabilities of uncertain timing or amounts using provisions, in accordance with Australian Accounting Standard AASB 137. These amounts primarily relate to employee entitlements such as long service leave and defined benefit superannuation. We maintain our

[60] Known as Integral Energy prior to 1 March 2011.

provisions at a level to cover our estimated numbers of employees accruing leave, salary growth, likelihood of taking leave and several other long-term demographic considerations.

To ensure we have set aside a correct amount, we engage a professional actuary on an annual basis to assess these factors and determine whether adjustments are required to the provisions.

The gains and losses in Table 22 for the 2009-14 period result from adjustments made to reflect the differences between the previous actuarial assumptions and what had actually occurred as well as the effect of changes in actuarial assumptions.

Vegetation management

Vegetation management represents a substantive and critical activity to Endeavour Energy. Endeavour Energy has mandated standards that set out the minimum clearances required for the safe operation of the distribution network. To ensure that we deliver value for money services we externally source a signficant majority of this function.

To implement appropriate contract management, incentivise our providers and target best performance our contracts are contingent on achieving full compliance with our standards.

For the 2009-14 period we were able to secure improved overall vegetation costs, however we were required to exercise aspects of our contracts relating to insufficient conformance with our mandated standards. The impact of both of these matters has resulted in lower than expected vegetation managent costs across the current regulatory control period.

In the 2014-19 period we are targeting further improvements to conformance with our standards. In the recent market tender process we have observed that the market has sought to price in the standard expected of them, and therefore we are forecasting increased costs for this activity. We consider vegetation management contributes to the achievement of the expenditure objectives and criteria, in particular managing bushfire, reliability and safety risk.

6 OPERATING EXPENDITURE

Drivers impacting our proposal for 2014-19

Our forecast operating expenditure recognises that delivering value for our customers is a key objective in the current landscape. We are facing a number of changes that are likely to increase the costs of performing our key functions as a DNSP. We have balanced these competing tensions by finding efficiencies in the proposed program to mitigate the impact on prices for our customers.

Endeavour Energy's forecast operating expenditure for the forthcoming regulatory period has been designed to support the distribution network and comply with our legislative obligations whilst incorporating significant productivity and efficiency improvements.

Our effort to reduce cost within the 2009-14 period has provided us with a solid platform to strive to contain average increases in our share of customers' electricity bills at or below CPI over the forthcoming regulatory period.

The actual operating expenditure for 2012-13 therefore represents an efficient starting base to forecast our operating expenditure requirements for the next period as we have responded to the incentives to be efficient by containing our total operating expenditure within the allowance set by the AER for the current period.

Factors that influence our cost

In order to ensure that our 2014-19 forecast operating expenditure reflects our expected expenditure requirements for the next period, we must consider a number of factors that would impact on this expenditure requirement. Some of the factors that will influence the level of operating expenditure required in the forthcoming regulatory control period are:

- regulatory obligations and changes to these obligations or the introduction of new obligations
- the particular environment of the DNSP and changes to this operating environment since the last determination
- the current condition of our assets and inherent relationship between forecast capital and operating expenditure and the consequential impact on operating expenditure from future capital investments
- forecast cost of inputs (i.e. labour, materials etc)
- implementation costs supporting reform initiatives.

Changes in environment

For the 2014-19 forecast operating expenditure, the changes in Endeavour Energy's operating environment have had a discernible impact on future operating expenditure requirements. These changes stemmed from a number of events that have occurred since the AER's determination for the current 2009-14 period and will impact the 2014-19 forecast period. These anticipated changes and trends are:

- increase in vegetation management costs with forecast improvements in compliance and increases in market cost
- the sale of Endeavour Energy's (then Integral Energy) retail business
- capital prioritisation and efficiency program costs
- cost escalation.

These are unavoidable increases in our cost base. However, we are also mindful of the concerns our customers have repeatedly voiced through our engagement with them. Customers are concerned with the rate of change in network prices over the last period.

6 OPERATING EXPENDITURE

Our performance in the current period and the circumstances we are expecting to face in the next period are critical factors we must take into account in developing forecast operating expenditure for the 2014-19 period. In addition to these factors, the Rules also require the AER, in making its decision on whether to accept the proposed forecast operating expenditure, to have regard to the extent to which the operating expenditure forecast includes expenditure to address the concerns of electricity consumers as identified by Endeavour Energy in the course of its engagement with customers.[61]

One of the findings from our engagement is customers' concern about electricity prices. Mindful of these concerns, Endeavour Energy's forecast expenditure contains savings to ensure that there is nil bill impact to customers as a result of the step changes listed above. These initiatives include:

- fully eliminating the cost impact of losing the synergies that we were able to realise previously as an integrated network/retail business
- eliminating the cost impact from a reduced capital investment over the 2014-19 period.

These changes to Endeavour Energy's operating environment and efficiency programs are discussed in further detail in the following section under 'Change factors'.

We therefore have forecast a total operating expenditure requirement for the next period of $1,384.3 million ($2013-14). We consider that this proposed forecast is an efficient amount that a prudent DNSP would require to achieve the operating expenditure objectives and reflects a realistic expectation of the demand forecasts and cost inputs. The result of this approach is a declining operating expenditure profile in real dollar terms over the next regulatory period.

Table 25: Forecast operating expenditure over the 2014-19 regulatory control period

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
Operating expenditure	267.6	272.4	281.2	278.7	284.4	**1,384.3**

Note: includes amounts for DMIA and debt raising costs. Numbers may not add due to rounding

[61] Clause 6.5.6(e)(5A).

6 OPERATING EXPENDITURE

Operating expenditure forecasting method

Our methodology has used a base year as a reference point for developing our operating expenditure forecasts for most cost categories. For the remaining costs we have used a combination of benchmark costs and individual project forecast to derive forecasts where appropriate. Our method has also explicitly incorporated efficiency savings and the likely impact of real cost labour escalation.

This section addresses the NER requirements for Endeavour Energy to provide information on the method used to develop the operating expenditure forecast and various information and matters pertaining to this forecast.[62]

Our 2009-14 period performance informs the development of the required operating expenditure requirement for the next regulatory period. Nevertheless, in deriving a forecast operating expenditure that reasonably reflects the operating expenditure criteria and that is sufficient for Endeavour Energy to achieve the operating expenditure objectives, we also considered and incorporated a number of factors on future operating expenditure requirements.

Our forecasting approach (as described below) considers how the costs needed to deliver the outcomes, consistent with the operating expenditure objectives, are influenced by current actual costs and the likely changes to these costs as a result of changes in:

- the costs of inputs
- regulatory obligations
- Endeavour Energy's operating environment
- the consequences of changes to capital prioritisation and efficiency programs.

Our forecasting approach, method and assumptions

To comply with the NER and to ensure that the nature of each cost category is appropriately accounted for in preparing the total forecast operating expenditure.[63] Refer to table 2.1 of the Reset RIN for the categories of distribution services to which our forecast relates.[64]

Our on-costs have both fixed and variable components and are consistently applied to each category of forecast operating expenditure. The extent to which on-costs are fixed is determined by the allocation of costs in accordance with the CAM approved by the AER and the quantum of services provided. On-costs that are not fixed are treated as variable costs.

We approached the development of the total forecast operating expenditure as follows:

1. The base step trend 'revealed cost' approach method was applied to the majority of Endeavour Energy's network maintenance activities, other operating costs and direct and indirect overhead operating expenditure. We have forecast operating expenditure at the category or activity level, where appropriate.

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[62] NER S6.1.2(2).

[63] NER, clause 6.5.6(a) and (b) (3).

[64] NER S6.1.2(1)(iv).

2. Other operating expenditure was forecast using benchmark costs or individual project forecasts where appropriate. These methods were applied to the derivation of the following costs:

- insurance costs
- demand management costs
- 'Loss of synergies' costs resulting from the termination of the transition service agreement with Origin Energy
- statutory charges for Endeavour Energy's property portfolio
- self-insurance amounts
- regulatory reset costs
- payment from provisions
- debt-raising costs.

Each forecasting method is further discussed below.

Forecasting assumptions

The Rules require Endeavour Energy to provide details of the key assumptions underpinning our forecast opex and a director's certification as to the reasonableness of these key assumptions.

The directors' certification is provided at Attachment 0.06. The summary below provides details of assumptions underlying our forecast opex. These are assumptions relating to facts or circumstances, the truth or correctness of which underpins or is highly material to the forecast of opex. We note that there are other key assumptions which apply solely to forecast capex and have been identified in Chapter 5.

Assumptions	Description
Current Endeavour Energy's structure and industry structure	We have prepared our forecast operating expenditure based on our current organisational structure and current financial system. We assume that there will be no material changes to these in the 2014-19 period.
Legislation and regulatory framework	The operating expenditure forecast had been developed based on: • the current applicable regulatory framework including the current version of the National Electricity Laws and National Electricity Rules in force at the time of developing the proposal • current legislation applying to Endeavour Energy including anticipated changes to obligations.
Base year	The actual operating expenditure Endeavour Energy incurred for the provision of standard control services in 2012-13 has been adopted as the efficient base year for deriving a forecast of recurrent opex. This actual opex has been adjusted for cost items that do not reflect the underlying operating profile to ensure that the proposed forecast operating expenditure reasonably reflects the efficient costs that a prudent operator would require to achieve the opex objectives, taking into account a realistic expectation of the demand forecast and cost inputs required.
Cost escalation	We have assumed that the real cost escalators used will be sufficient to reasonably reflect a realistic expectation of the cost of inputs in the 2014-19 period. In addition, we have also assumed that: • wages for staff with engineering/technical skills will rise in line with the EGWWS wage forecasts • wages for all other non-engineer/non-technical staff will rise in line with the wage forecast for general labour • there are no real cost changes for other non-labour cost inputs (i.e. these are assumed to change with CPI).
Customer engagement	We have engaged with stakeholders in developing this regulatory proposal in accordance with the stakeholder engagement process outlined in the NER

Base step trend 'revealed cost' method

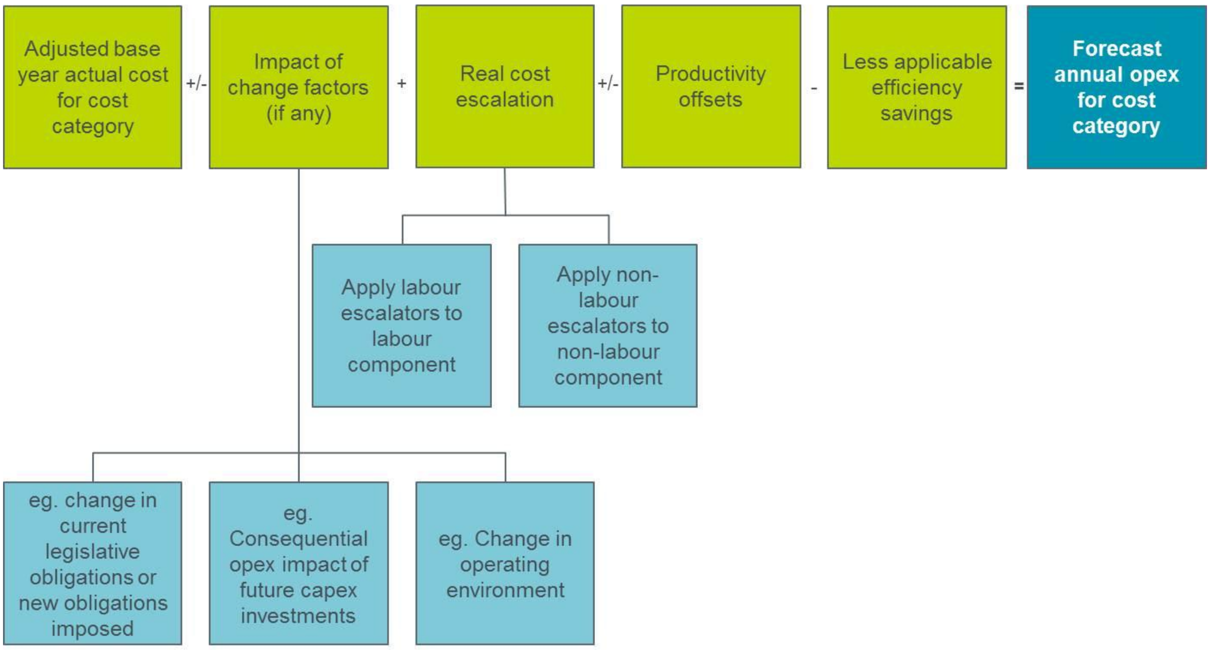
The base step trend 'revealed cost' method, commonly used by the DNSPs and the AER to develop forecast operating expenditure, is appropriate for forecasting recurrent expenditure because the base year amount encapsulates the actual annual cost currently required to provide standard control services.[65]

The base year method uses the following inputs to develop the forecast operating expenditure:

- the base year operating expenditure, adjusted to remove one off or non-recurrent costs
- forecast savings from Endeavour Energy's cost-reduction strategies
- forecast savings from Networks NSW (Network Reform) efficiency programs
- impact of change factors on forecast costs
- real cost escalators.

The detailed forecasting approach for activity and category level forecasts is discussed in our forecasting methodology, Attachment 0.08. The diagram below depicts the application of the base year method by Endeavour Energy. Each stage of the method is discussed in further detail below.

Figure 20: Application of base-step-trend method



Base year expenditure

Historical expenditure, particularly expenditure in the base year plays a key role in forecasting operating expenditure when using the base-step trend 'revealed cost' methodology. Endeavour Energy has used the actual operating expenditure for 2012-13 for the relveant operating expenditure categories as the base year in developing the operating expenditure forecasts for the 2014-19 regulatory period. The year 2012-13 is the fourth year of the current regulatory period and is used because it is the latest actual operating expenditure data available at the time of preparing the forecast. It also had been reviewed by an external auditor as part of the annual regulatory reporting to the AER.[66]

[65] This is consistent with the AER's view in its decision for Aurora Pty Ltd, 2012-13 to 2016-17, November 2011, pp 156 - 158.

[66] Reference annual regulatory reporting to the AER.

6 OPERATING EXPENDITURE

The base year (or underlying operating expenditure) is in the table below:

Table 26: Base operating expenditure with steps and trends

Base year expenditure $m; Real 13-14	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Underlying operating expenditure	**276.4**	**271.6**	**265.0**	**258.5**	**252.2**	**246.0**	**240.0**
Adjustments and changes to the base year expenditure							
ANS and metering services transferred to SCS	-	-	(56.5)	(58.5)	(61.4)	(62.1)	(64.2)
Net vegetation management costs	-	22.2	23.1	25.4	27.6	26.7	27.8
Capital expenditure prioritisation	-	-	-	4.2	8.1	-	-
Output growth	-	8.1	16.1	24.0	31.7	39.2	46.6
Escalation (from 2012-13)	-	6.8	13.4	19.9	26.2	32.3	38.3
Other (including savings)	-	11.8	2.6	(5.0)	(7.2)	(7.6)	(8.3)
Total SCS operating expenditure	**276.4**	**320.5**	**263.7**	**268.4**	**277.1**	**274.6**	**280.2**

As evident in the table above, the base year total actual operating expenditure has been adjusted for one off expenditure to ensure the base amount reflects recurrent expenditure only. Specifically, the impact of an actuarial adjustment for employee entitlements has been removed as this is an unpredictable, non-recurrent cost. The base year cost for each category is then further adjusted to account for any change factors and trends that alter costs from the current amount required to provide standard control factors.

The base-step trend 'revealed cost' methodology works together with the EBSS incentive mechanism applied by the AER to provide Endeavour Energy with incentives to become more efficient and reduce our operating expenditure. We have responded to these incentives during the 2009-14 period, demonstrated by our positive carryover, which is discussed further below.

As discussed eariler in the chapter, our efficiency intitiatives (C7, Project Challenge, Project Compete and Network Reform Program) have also contributed to our efficiency gains made during the 2009-14 period. The $76.6 million (real, $13-14) in savings achieved up to and including 2012-13 are incorporated into the forecasts through the use of 2012-13 actual operating expenditure as the base year.

Change factors

As discussed above, the base operating expenditure reflects the efficient costs of providing standard control services in Endeavour Energy's current operating environment. However, both changes in the current circumstance and new factors that arise in the forthcoming regulatory period will impact our forecast operating expenditure requirements.

These impacts are obviously not reflected in the base amount and therefore would need to be added to the base amount to develop a forecast operating expenditure for the forthcoming regulatory period that reasonably reflects the operating expenditure criteria.

In our base year forecasting method, Endeavour Energy refers to these circumstances and factors collectively as 'change factors'. These 'change factors' could arise from:

- new obligations or increases in the scope/standard of current regulatory obligations
- changes in Endeavour Energy's operating environment
- the interaction between forecast capital expenditure and forecast operating expenditure; e.g. the consequential operating expenditure from future capital investments.

These increases are often referred to as 'step changes' or step increases by other DNSPs and the AER in applying the base year method. In its application of the base year method in a number of decisions, the AER recognises that 'step changes' are legitimate expenditure that reflects the operating expenditure criteria. The AER stated that:

> *The AER recognises Powerlink may be subject to changes in regulatory obligations or the operating environment that are not reflected in its base year expenditure. The base operating expenditure should therefore be adjusted to account for these 'step changes'.*[67]

As noted in the previous section, a number of changes in Endeavour Energy's operating environment have impacted on our operating expenditure requirements for the 2014-19 period and include:

[67] AER, Draft decision, Powerlink Transmission determination 2012-13 to 2016-17, November 2011, p 186. See also the AER's decision for Aurora Energy Pty Ltd 2012-13 to 2016-17.

6 OPERATING EXPENDITURE

Change factors for the base year method	Description
Newly classified alternative control services	Type 5 and 6 metering services and ancillary network services (formerly miscellaneous and monopoly) have been reclassified as alternative control services for the 2014-19 period. Accordingly, we have removed the cost related to these services from our standard control operating expenditure forecast for the 2014-19 period.
Vegetation management	For 2014-19, an increase in annual vegetation management costs arise due to observed increases in contract conformance costs consistent with our ongoing focus on the achievement of required program compliance for this critical risk management function. In addition we have experienced additional cost movements in market delivered contracts secured by Endeavour Energy.
Capital prioritisation costs	As noted in the capital expenditure chapter, the 2014-19 capital expenditure program represents a substantial decrease compared to our capital expenditure for the 2009-14 period. This is a reflection of our assessment of risk, several efficiency initiatives and a return to a more sustainable level of investment in our network. This creates a step-up in our operating expenditure compared to our base year. This step-up reflects the costs of aligning our labour force and undertaking additional maintenance expenditure. We expect these initiatives and our capital program reduction will deliver savings in excess of these costs into the future.
Output growth	Our workload has increased as a result of our substantive 2009-14 capital program and forecast expenditure and customer and demand growth. As a result of this, we are required to maintain and operate a larger number of assets and network. This creates a step-up in our workload rather than unit costs.
Escalation	In accordance with a base-step-trend approach we have trended our base year operating expenditure to reflect nominal cost pressures from input labour, materials and contractors. For the purposes of our regulatory proposal we have assumed general cost increases in line with the forecast rate of inflation.
Savings programs	As previously noted, significant savings have been achieved during the 2009-14 regulatory period. Our base year expenditure reflects these savings, however additional savings are forecast for the 2014-19 period. These savings are the result of a mix of ongoing internal efficiency programs and Networks NSW reform programs.

While not reflected in Table 26, our forecast operating program reflects a continuation of the significant savings initiatives from the current period. These savings have been applied across our forecast, eliminating several potential cost inreases and reducing the actual upward steps. The key changes are explained in more detail below.

Cost saving initiatives during the 2014-19 period

The savings from the C7 Program, Projects Challenge and Compete, and Network Reform have a pivotal role in ensuring that the total forecast operating expenditure reasonably reflects the efficient amount that an operator in Endeavour Energy's circumstance would need.

Endeavour Energy's cost-reduction strategies

Projects Challenge and Compete reflect our goal of implementing sustainable efficiency savings over the next five years. The savings identified from Projects Challenge and Compete during the 2009-14 period are included in our efficent historical base for the 2014-19 regulatory period as these productivity improvements continue into the future.

The table below the page shows the expected operating expenditure savings from the above strategies.

Table 27: Endeavour Energy ongoing savings from efficiency programs

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
C7 Program	25.0	24.9	24.8	24.8	**24.8**	**124.3**
Project Challenge	21.7	21.8	21.7	21.8	21.8	**108.7**
Project Compete	6.2	6.2	6.2	6.2	**6.2**	**30.9**
Total cost reduction	**52.8**	**52.8**	**52.8**	**52.8**	**52.8**	**263.9**

Savings initiatives from Networks NSW Reform

Network Reform has resulted in considerable change and will deliver a more efficient, lower cost electricity distribution service to customers that is financially sustainable, eliminates unnecessary waste, and maintains the reliability and sustainability of the network in a way that is safe for employees and the public.

Savings to operating expenditure of $40.3 million (real, 2013-14) for the 2014-19 period are expected from the implementation of Network Reform Program and these savings have been incorporated into the forecast operating expenditure requirement.

The table below shows the expected operating expenditure savings from the four initiative streams of the Program.

Table 28: Endeavour Energy savings from Network Reform Program

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
New operating model	1.8	2.1	2.1	2.1	2.1	**10.2**
Strategy and policy	1.9	3.2	3.2	3.2	3.2	**14.9**
Capital expenditure efficiency	-	-	-	-	**-**	**-**
Procurement and logistic	1.9	3.3	3.3	3.3	3.3	**15.1**
Total cost reduction	**5.6**	**8.7**	**8.7**	**8.7**	**8.7**	**40.3**

Attachment 0.02 provides further details of our cost reduction initiatives.

Increase in vegetation management costs

Vegetation management is an integral function of our business. Our focus for the 2014-19 period remains on fully achieving our our compliance obligations in this regard. It is our view that this activity directly supports all four operating expenditure objectives contained in clause 6.5.6(a) of the NER. A reduction to this forecast will impact our ability to comply with our obligations and provide a safe, secure and reliable service particularly with regard to bushfire and reliability risk.

Vegetation management is a critical risk management function that directly impacts on the safe operation of our network. Consequenetly, our vegetation management contracts and the resultant costs are conformance based. The activation of some of these conformance elements of our contracts have resulted in a lower than anticipated vegetation management expenditure in the current period.

To ensure this service is delivered at the most efficient cost to customers we externally source a significant majority of our vegetation management activities. A key driver of our increased costs in this area is due to upward movements in market delivered contracts secured by Endeavour Energy for the next regulatory control period. We have adopted a prudent approach to sourcing these external contracts and have selected the least cost, compliant provider.

It is our view that observed increases in the market delivered costs for vegetation management services are a result of the market pricing the expected conformance with the vegetation managenet standards. We have forecast improved conformance, in line with recent trends, which has therefore increased our costs from the current period.

Table 29: Endeavour Energy estimate of vegetation management program costs

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
Vegetation management	63.6	64.9	66.1	64.3	64.5	**323.4**

As mentioned, we have more than offset this upward step in costs through a number of efficiency programs and cost saving initiatives.

Capital prioritisation and efficiency program

As noted in the capital expenditure chapter, the 2014-19 capital expenditure program represents a substantial decrease compared to our capital expenditure for the 2009-14 period. This is a reflection of an assessment of risk, several efficiency initiatives and a return to a more sustainable level of investment in our network. The overall investment portfolio has been optimised using an investment prioritisation model that produces an assessed risk ranking for all proposed capital expenditure projects and programs.

This investment prioritisation creates a step-up in our operating expenditure compared to our base year and reflects the costs of redundancy and undertaking additional maintenance expenditure. These are the efficient costs that a prudent business would require to manage the significant reduction in capital expenditure. A business cannot alter its operational size without incurring these transitional costs. We have excluded labour cost impacts and overheads reallocated from capital to operating expenditure from our operating expenditure forecast.

We expect that the capital program reduction will deliver savings in excess of these short-term increased operating costs into the future. We have incorporated significant network reform savings into our forecast expenditure to assist in addressing the step-up in our operating expenditure.

Output growth

Output growth relates to increases in the number of activities and operations that Endeavour Energy is required to undertake as part of the efficient operations of the distrubution network. For the 2014-19 period this growth is a result of growth in our customer numbers, network demand and our capital and operating programs during the 2009-14 period. As a result of this, we are required to maintain and operate a larger number of assets connected to our network. This creates a step up in our workload rather than unit costs.

The drivers for output growth include:

- Maintenance operations have been escalating due to the general increase in the number of assets being managed by Endeavour Energy. Further, this larger number of assets will require a greater number of inspections and preventative maintenace activities in order to extend the operational life of the assets being managed.
- The National Energy Customer Framework (NECF) imposes a range of obligations on the NSW DNSPs. Many of these obligations include activities that require staff to undertake either new activities

or more of the same types of activities. For example, notifications of outages due to network maintenance and undertaking visual checks of the network configurations to ensure that all customers expected to be impacted by each outage have been identified and confirm that any customer with registered life support equipment has the required notice.

- Customer connection requests, in particular solar generator connection requests. Since the introduction of the NSW Solar Bonus Scheme (SBS) in 2010, Endeavour Energy has observed a marked increase in the number of connection requests that it receives from customers.

  In addition, Endeavour Energy has identified the installation of rooftop PV generators as a potential community safety risk. Consequently we have been undertaking safety and compliance inspections on these installations at rates significantly greater than before the introduction of the SBS.

  We also note that despite the SBS being closed as of 1 July 2012, the rate at which rooftop PV is being connected to our network has not reduced, and is therefore expected to continue to impact on the amount of work required in response.

In addition to these factors we expect that additional output growth drivers may arise during the 2014-19 period. Due to the uncertainty surrounding these factors we have not been able to incorporate their impact on our operating expenditure at this point in time. We may be in a position to do so at the time of our revised regulatory proposal or within the period via a pass through, if applicable. These include, but are not limited to:

- SCER rule change requests: There are currently SCER rule changes that are being considered by the AEMC that may have material impacts on the amount of work that may need to be undertaken by Endeavour Energy over the 2014-19 period. One such review is considering amendments to the definition of the connection point between a customer's installation and our distribution network. If the boundary of our network is extended to include items such as service wires etc, the additional maintenance activity and inspections we would be required to undertake would increase significantly. At this stage the changes are still being considered and the final outcome to be known. Therefore we are unable to estimate the extent of additional activity we may be required to undertake into the future.
- Pioneer Scheme: The AER's approval of our transitional Connection Policy and in particular those clauses relating to the Pioneer cost share reimbursement scheme will have an impact on our expenditure forecasts. Endeavour Energy's previous Connections Policy contained a cost share reimbursement scheme that was limited in its scope. The AER's connection charge guidelines for electricity retail customers, which are implemented by our new Connections Policy, greatly expand the scope of the reimbursement scheme. Management of this expanded scheme is likely to require additional operating expenditure and IT capital investment that has not been included in the expenditure forecasts in this proposal as there has been insufficient opportunity to evaluate the scope of work required.
- Substantial new connections: our demand forecasting process is imperfect and does not identify all new major connections that may occur during the forecast period. To the extent that any such connections were not identified at the time of preparing our last peak demand forecast, no expenditure has been included for associated connection works in our forecast capex. An example of such a potential connection arises from the Federal Government's recent announcement of the establishment of a second Sydney Airport at Badgery's Creek, within the Endeavour Energy network area. At this stage it is unknown what impact this will have on our network or the timing of any works and accordingly we have not been able to make any allowance in our expenditure forecasts or for a contingent project for the necessary connection works.

Real cost escalation

Endeavour Energy engaged Competition Economists Group (CEG) to provide expert advice and to estimate cost escalation factors in order to assist it in forecasting future operating expenditure based on changes in unit costs for the 2014-19 regulatory period.

CEG advised that the Labour Price Index is the most appropriate measure of labour price. The Independent Economics report and calculation methodology are provided at Attachment 0.05.

The labour escalators in the table below represent the real cost escalators to be applied in developing forecast operating expenditure by financial year. For award labour we have applied *Labour – util – Endeavour – FY*, which is based upon actual and committed labour increases combined with Independent Economics forecasts for utilities sector wage price index growth. For contract labour we have applied *Labour – WPI all – FY*. We have not applied real non-labour escalators to our operating forecast and will offset these costs through efficiency savings.

Table 30: Real labour escalators for 2014-19

Real cost escalators (%)	2014-15	2015-16	2016-17	2017-18	2018-19
Labour - util.- Endeavour - FY	1.2%	1.6%	2.1%	2.1%	2.0%
Labour - WPI prof. serv. - FY	0.8%	1.3%	1.8%	1.9%	1.9%
Labour - WPI all - FY	0.6%	1.1%	1.7%	1.8%	1.8%

Other operating expenditure forecasts

Non-routine costs are not a function of the current base year costs; therefore the base step trend ‘revealed cost’ method would not be appropriate. Rather, other factors such market benchmarks (insurance premium costs), statutory obligations (statutory charges for properties holding) or the nature of the costs themselves (demand management, loss of synergy costs, payment from provisions) require the use of individual project forecasts.

The summary below shows the inputs used to derive the forecast of these costs.

Cost categories	Forecasting method and inputs
Demand management costs	Total forecast is derived from the application of unit rates to expected work volumes required to deliver demand management projects. Further details on our proposed demand management activities can be found in Attachment 5.34.
Insurance premium costs	Market insurance premium applied to the value of assets insured.
Regulatory reset cost	Endeavour Energy incurs cost for preparing regulatory proposals. This cost is expected to be incurred in years 3 to 5 of the 2014-19 regulatory period. While costs are expected to increase in real terms, Endeavour Energy had proposed the same amount that it had incurred or expect to incur in the current period in relation to regulatory reset costs. This is a reduction in real terms as real cost escalation had been offset by productivity improvements and efficiency savings.
Statutory charges – Land tax	Land tax rates set by the NSW Government applied to the value of property portfolio.
Statutory charges – Council rates	Council rates set by IPART applied to the value of property portfolio.

Forecast of debt-raising costs

Debt-raising costs are incurred each time a debt is raised or refinanced. Endeavour Energy would need to raise or refinance debt to fund expenditure incurred in achieving both the capital program and other objectives in the 2014-19 regulatory period. Endeavour Energy would therefore incur debt-raising costs which need to be accepted by the AER.

We adopted the AER's method for the calculation of debt-raising costs, that is, debt-raising costs were calculated by applying a benchmark debt raising unit rate to the debt portion of our regulated asset values.

Endeavour Energy's total forecast operating expenditure includes $16.1 million (real, $13-14) for debt-raising cost for the 2014-19 regulatory period.

Retail sale dis-synergy costs

As noted earlier, on 1 March 2011, the sale of the Integral Energy retail business to Origin Energy was completed, triggering a 'Retail project event' as defined in the current AER determination. The costs transferring to standard control services in the pass-through application are set out in the table below. These estimates excluded any transaction or stranded costs associated with the retail project event.

Table 31: Endeavour Energy estimate of cost increases for retail dis-synergy costs

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Cost to distribution business	12.2	11.4	11.6	12.0	12.2	**59.4**

Endeavour Energy was appropriately structured to support a distribution, unregulated and retail business. The retail sale therefore results in the reallocation of some corporate costs to standard control services. While we transition to a network-only business we have delivered significant efficiency initiatives to offset the impact of these dis-synergy costs. This meant that we did not pass through the $48.8 million (nominal) approved by the AER in the 2009-14 period.

Similarly, for the 2014-19 period we have forecast substantial savings from both our efficiency programs and Networks NSW initiatives that will offset these dis-synergy costs.

Movement in provisions

Our base year operating expenditure of $283.6 million also contains year-end adjustments of $7.2 million to reflect actuarial gains and losses in the assessments of our employee entitlements obligations. Actuarial gains and loss are changes in the present value of these obligations.

These gains and losses resulted from adjustments made to reflect the differences between the previous actuarial assumptions and what had actually occurred as well as the effect of changes in actuarial assumptions. These adjustments are included in our actual operating expenditure for 2012-13 as required by Accounting Standards; however, they have been excluded from the base operating expenditure to ensure that the base operating expenditure amount reflects the underlying ongoing operating expenditure needed to undertake the required activities to provide standard control services. This approach is consistent with that used to forecast our 2009-14 period operating expenditure allowance approved by the AER.

We note that in recent decisions, the AER has reversed 'movement in provisions' from the base amount to reflect the cash payout rather than the amount accrued. The AER's approach effectively represents 'cash accounting' instead of 'accrual accounting'. Under the AER's approach, the forecast operating expenditure would reflect the estimated cash to be paid in the next five years in relation to provision liabilities. Under the accrual approach we have adopted, the forecast operating expenditure represents the amount that accrues (e.g. long service leave, annual leave) based on actual year-to-date results.

We have not adopted the AER's approach of cash accounting because it is likely to result in price shocks to customers as well as imposing further costs on Endeavour Energy which we must recover from customers. Future amounts are subject to forecasting error particularly given the volatility of future discount rates which are a major input into these calculations.This is fundamentally against the National Electricity Objective of ensuring the long term interest of customers with respect to price.

A principle of Australian Accounting Standard '137 Provisions, Contingent Liabilities and Contingent Assets' is that a provision should be recognised when:

- an entity has a present obligation (legal or constructive) as a result of a past event.
- it is probable that an outflow of resources embodying economic benefits will be required to settle the obligations.
- a reliable estimate can be made of the amount of the obligation.

The recognition of a provision often does not coincide with the cash outlay as the provision should be recognised as soon as a present obligation exists. For example, employees are compensated for their service in the form of salary, associated annual leave, long service leave and superannuation benefits. Endeavour Energy recognises these liabilities and costs as soon as the employees have rendered their services; e.g. an additional year of service.

The cash outlay, however, is made when the employees take the leave entitled to them or upon exit from Endeavour Energy. This can be dependent upon employee behaviour and in the case of long-term employee benefits, the cash outlay can often occur many years after the recognition of the original liability. A cash payment approach therefore will introduce lumpiness in the forecast operating expenditure profile, resulting in volatility of the revenue required to recover this forecast operating expenditure and consequently subjecting customers to a volatile price path.

An accrual approach on the other hand would ensure that the costs are recovered at a smoother rate over time; by setting aside amounts as soon as the obligation arises. When the cash is paid, it is drawn from the provision. There is no impact on the operating expenditure.

The second concern we have about the AER's cash approach is that it will result in a permanent difference between the statutory and regulatory accounts, consequently requiring the maintenance of two separate accounting systems at significant additional costs to Endeavour Energy (and all other DNSPs). These costs will need to be passed onto customers, causing unnecessary increases in prices.

It is because of these concerns over the impact on our customers that we have not adopted the AER's cash accounting approach.

Self insurance

Endeavour Energy adopts prudent risk and asset management measures to ensure the safety, reliability and sustainability of electricity supply to all of its customers. We do this in a number of ways such as purchasing insurance, asset design, standards; systems, processes and procedures.

We are compensated for undertaking risk prevention/mitigation activities under the regulatory framework through allowances under forecast capital expenditure, forecast operating expenditure (including external insurance and self insurance), and the rate of return on assets and nominated pass-through events.

Endeavour Energy propose a self-insurance operating expenditure allowance for workers compensation of $0.5 million per annum. This is a predictable and measurable risk that relates to workers compensation payments which exceed available reserves. Endeavour Energy is registered as a self-insurer under NSW legislation and has estimated an efficient premium based on actuarial advice. Refer to Attachments 6.13 and RIN template 2.15 for further details.

Endeavour Energy is not proposing any other self-insurance costs for the 2014-19 period.

6 OPERATING EXPENDITURE

Operating expenditure program 2014-19

Our proposed forecast operating expenditure program for the next five years is to ensure that we continue to keep our network safe, reliable, sustainable and complying with our legislative obligations. This proposed program of work will be delivered effectively and efficiently so that our customers will not be unduly burdened.

The purpose of this section is to identify Endeavour Energy's total forecast operating expenditure for the next five years by cost categories. This section also provides a high-level overview of the activities underpinning each cost category and the specific change factors applicable to each (if any).

We propose a total forecast operating expenditure for the next five-year period of 1,384 million (real, $13-14). We consider this amount is needed to achieve each of the operating expenditure objectives set out in the Rules.

This forecast represents expenditure that had been properly allocated to standard control services in accordance with the policies and principles set out in Endeavour Energy's CAM that was approved by the AER on 2 May 2014.

Table 32: Forecast operating expenditure over the 2014-19 regulatory control period

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	TOTAL
Network operating costs	22.7	23.8	24.7	24.3	24.9	**120.4**
Inspection	27.7	28.4	29.1	28.3	28.5	**142.0**
Maintenance and repair	59.0	57.5	59.8	59.0	59.9	**295.2**
Vegetation management	63.6	64.9	66.1	64.3	64.5	**323.4**
Emergency response	46.4	48.2	50.4	52.0	55.0	**252.0**
Network maintenance	20.6	21.1	21.6	21.8	22.2	**107.4**
Customer service	5.4	5.5	5.7	5.7	5.8	**28.1**
Other operating costs	18.3	19.0	19.6	19.2	19.4	**95.5**
DMIA	0.6	0.6	0.6	0.6	0.6	**3.0**
Debt raising costs	3.2	3.4	3.5	3.5	3.6	**17.2**
Total operating expenditure for PTRM	**267.6**	**272.4**	**281.2**	**278.7**	**284.4**	**1,384.3**

Note: numbers may not add due to rounding

6 OPERATING EXPENDITURE

System maintenance operating expenditure

For the categories associated more directly with the network we propose forecast operating expenditure of $1,120 million for the next five years. This operating expenditure is to maintain our network and primarily consists of inspection, maintenance and vegetation management costs. An explanation of each category of system maintenance operating expenditure is as follows:

Inspections. Routine asset inspection and condition monitoring activities include field and aerial inspection of overhead distribution assets (poles, pole top structures, conductors, substation structures, transformers, high and low-voltage switchgear, and other distribution electrical equipment), powerline to ground and vegetation clearances, thermography of powerline and substation structures, and non-destructive testing of power transformers and switchgear.

Maintenance and repair. This category covers all maintenance and repair activities on network assets, it excludes fault and emergency repairs and restoration of supply for planned and unplanned interruptions which are categorised as emergency response. Components include maintenance and repair of distribution powerline equipment, damaged or inoperable switchgear, distribution and zone substations, and customer service mains.

Vegetation management. This work, mainly carried out by external contractors, reduces safety hazards and interruptions to supply on our overhead electricity network. Compliance with this policy is a critical control measure associated with management of bushfire and community safety risk. Vegetation management must be done regularly to ensure a reliable and safe electricity supply. It must also be done in a way that is sensitive to environmental and community issues.

Emergency response. This covers fault and emergency repairs and restoration of supply for planned and unplanned interruptions caused by events such as storms, equipment failures, acts of vandalism, and vehicle collisions. When notified of an interruption to customer supply, Endeavour Energy promptly dispatches field employees to deal with the fault.

Network maintenance operating cost. This cost category covers other activities that are required to support the maintenance of the network itself such as: fire mitigation (excluding vegetation management), field training and any other cost required for the safe operation and maintenance of the distribution network.

Operations, support and other operating expenditure

We propose a total forecast operating expenditure of $244 million to operate and support our network and our business. This program consists of the following categories of expenditure:

Network operating costs. This category of costs covers operating costs required to manage the network such as: staffing of the control centre, operational switching personnel, outage planning personnel, and provision of authorised distribution personnel. It also covers support activities directly related to the network such as: demand forecasting, procurement, logistics and stores, information technology (IT) costs directly attributable to distribution operation, and land taxes.

Customer service. This activity includes call centre and operational activities relating to customer interaction and reporting on issues such as: distribution faults and safety hazards, complaints about the quality and reliability of supply, queries on new connections, disconnections and reconnections, and queries on improving power factor or load factor.

Other operating costs. This category includes all other costs that are incurred in the provision of standard control services but are not related to the operation of the network itself, such as operating tools and equipment purchases, billing and revenue collection and regulatory costs.

6 OPERATING EXPENDITURE

Meeting the Rules

Endeavour Energy has proposed a total forecast operating expenditure for the 2014-19 period that it considers is required in order to achieve each of the operating expenditure objectives (operating expenditure objectives) listed in clause 6.5.6(a) of the NER.

The AER is required to make a decision on whether to accept or reject our total forecast operating expenditure. The AER must accept the total operating expenditure forecast if it is satisfied that the forecast of required operating expenditure reasonably reflects each of the operating expenditure criteria (operating expenditure criteria), having regard to the operating expenditure factors (operating expenditure factors).

To enable the AER to make its decision, the NER require Endeavour Energy to comply with specific information requirements in Clause 6.5.6 and Schedule 6.1.2 of the Rules. This includes an obligation to comply with the requirements of any relevant regulatory information instrument.

In regards to the RIN, Endeavour Energyhas undertaken a comparison of the high level requirements contained in the Expenditure Forecast Assessment Guideline against the specific requirements in the RIN. All matters covered by the Guideline are addressed by the RIN requirements which have been customised to reflect Endeavour Energy's business. Accordingly, Endeavour Energy's RIN response meets the requirements of the Guideline as required by the AER's Framework and Approach paper."

In the sections below we briefly identify how we have met the opex objectives, criteria and factors. In Attachment 0.03 we provide more detailed information.

Achieving the operating expenditure objectives

The Rules states that Endeavour Energy's forecast operating expenditure must be the expenditure that it considers is needed to achieve each of the outcomes listed in clause 6.5.6(a), known as the 'operating expenditure objectives' (operating expenditure objectives). These objectives are[68]:

- meet or manage the expected demand for standard control services (objective 1)
- comply with all applicable regulatory obligations or requirements (objective 2)
- maintain the quality, reliability and security of supply of standard control services and of the distribution system through the supply of standard control services (objective 3)
- maintain the safety of the distribution system through the supply of standard control services (objective 4).

In order to achieve each of the operating expenditure objectives, we must have the required capabilities, personnel and systems to achieve them. For example, one of the operating expenditure objectives is to maintain the safety of the distribution system through the supply of standard control services. In undertaking this activity and in operating the necessary systems, Endeavour Energy must incur maintenance operating expenditure.

Our total forecast operating expenditure therefore comprises the costs of undertaking all the related activities and to operate the necessary systems to deliver each of the operating expenditure objectives listed above. Our total forecast operating expenditure comprises three cost groups and the summary over the page shows the operating expenditure objective/s for each cost group.

[68] See clause 6.5.6(a) for exact wording.

6 OPERATING EXPENDITURE

Operating expenditure cost group	Activities	Operating expenditure objectives achieved
System maintenance operating expenditure	Maintenance operating expenditure is required to undertake various activities on Endeavour Energy's electrical network. These activities, and associated cost, are critical to achieve all four operating expenditure objectives.	All operating expenditure objectives
Operation, support and other expenditure	Operation expenditure are costs incurred in undertaking the required activities to directly support the operation of Endeavour Energy's electrical network. Support expenditure is necessary for the normal operation of Endeavour Energy as a business such as management costs, financial reporting or human resources management costs. These costs would be found in any typical business. They are essential to the effective running and operation of the network and therefore required to achieve all of the operating expenditure objectives.	All operating expenditure objectives

Meets forecasting requirements

The NER state that Endeavour Energy's forecast operating expenditure must meet the requirements contained in 6.5.6(b). Our operating expenditure forecast must:

- comply with the requirements of any relevant regulatory information instrument
- be for expenditure that is properly allocated to standard control services in accordance with the principles and policies set out in the CAM for the DNSP
- include both:
    - the total of the forecast operating expenditure for the relevant regulatory control period
    - the forecast operating expenditure for each regulatory year of the relevant regulatory control period.

Endeavour Energy has complied with these requirements. The AER issued a RIN for the 2014-19 determination to Endeavour Energy on 7 March 2014. We have completed this RIN in accordance with the requirements. Our forecast has been prepared in accordance with the CAM approved by the AER on 2 May 2014, Attachment 0.07. Additionally, we have provided our operating forecast in total and for each year of the 2014-19 regulatory control period as detailed earlier in this chapter and in our PTRM, Attachment 4.02.

Approved Cost Allocation Method

For the current regulatory period, Endeavour Energy applied the CAM that was prepared in accordance with clause 11.15 of the NER (the Transitional Rules). Specifically, this CAM:

- Gave effect to, and was consistent with the Accounting Separation Code for Electricity Distributors in NSW prepared by the Independent Pricing and Regulatory Tribunal (IPART). This Accounting Separation Code was deemed by the Transitional Rules to be the Cost Allocation Guidelines made by the AER for the 2009-14 regulatory period.

- Was used in preparing Endeavour Energy's RINs to the AER for the 2009-14 regulatory period.

Our CAM with revised allocators that complied with the AER's cost allocation guidelines was approved by AER on 2 May 2014.

Broadly, we disaggregate costs in accordance with the AER's service classification and then further allocate costs by organisational unit, activity, sub-activity and expense element. Most of the cost categories comprising Endeavour Energy's total forecast operating expenditure were derived using a base-step trend 'revealed cost' approach. For other shared costs that were forecasted using a 'bottom-up' approach, the approved allocators were applied to ensure only costs relating to standard control services were included in the total forecast operating expenditure.

We undertake cross checks through the management assurance process and the independent assurances processes to certify that the value of costs reported at the total level is equivalent to the sum of costs reported at the lowest level of classification.

The approved CAM can be found at Attachment 0.07.

Reasonably reflecting the operating expenditure criteria

The AER must accept Endeavour Energy's forecast of required operating expenditure if it is satisfied that the total forecast operating expenditure reasonably reflects each of the operating expenditure criteria, being:

- the efficient costs of achieving the operating expenditure objectives
- the costs that a prudent operator would require to achieve the operating expenditure objectives
- a realistic expectation of the demand forecast and costs inputs required to achieve the operating expenditure objectives.

In making this decision, the AER must have regard to the operating expenditure factors as well as the information included in or accompanying Endeavour Energy's regulatory proposal, written submissions and any analysis undertaken by or for the AER.[69]

At the time of our 2009-14 regulatory proposal, we engaged NERA to provide expert economic advice on the interpretation of the opex criteria and on how to demonstrate that the forecast opex reasonably reflects these criteria. In 2014, we engaged NERA to provide an updated view on its initial report in light of changes to the NER for economic regulation.

An important element of NERA's advice is that there are no directly observable measures of efficiency. NERA considered that a practical demonstration that the forecast expenditure reasonably reflects the expenditure criteria can be achieved by:

- Demonstrating that the process the DNSP employed in developing its forecast expenditure is efficient and prudent. In this respect a number of the capex factors relate to the process used by the DNSP.
- Using indicators to assess the reasonableness of the result and to inform a decision on whether the resulting forecast expenditure (from applying a prudent forecasting approach) reasonably reflects the efficient cost. In this respect, a number of the capex factors represent partial checks of the forecast.

[69] Clauses 6.10.1(b) and 6.11.1(b) of the Rules.

6 OPERATING EXPENDITURE

Forecasting process

Our expenditure forecasting process is based on meeting our regulatory obligations, and draws on our expert understanding of our network and the functions we have to perform in our role as a DNSP. In terms of demonstrating that our forecasting process is efficient and prudent, we have provided evidence in Attachment 0.03 to show that:

- We have effective policies and procedures to inform our expenditure decisions and our planning processes.
- Our governance processes ensure that expenditure decisions are appropriately delegated and have effective financial controls.

In terms of forecasting opex for the 2014-19 period, we have adopted a 'fit for purpose' approach that comprises the following steps:

- Disaggregate Endeavour Energy's total opex into various cost categories. These cost categories represent the costs of undertaking a set of related activities to provide standard control services and to achieve the opex objectives (for example, maintenance opex, system control, finance, human resources etc).
- Assess the nature of each cost category and determine the appropriate forecasting method that would result in a forecast cost that reasonably reflects the efficient cost that a prudent operator would need to achieve the opex objectives, based on a realistic expectation of demand forecast and cost inputs for that particular cost category.

We consider that this approach ensures that the nature of each cost category and its relevant underlying drivers are appropriately accounted for, such that the resulting forecast opex is reflective of the efficient costs that a prudent operator would require to achieve the opex objectives. This process gives us confidence that our total forecast opex would reasonably reflect the opex criteria and ensures that the National Electricity Objectives and the Revenue and Pricing Principles are met, especially that we are afforded a reasonable opportunity to recover at least the efficient cost we expect to incur in the 2014-19 period.

This approach to forecasting total opex that selects the most appropriate methods for the relevant cost categories would be expected to be the approach that DNSP would undertake to ensure that the resulting forecast expenditure reasonably reflects the opex criteria. Throughout this process, as well as considering the nature and drivers of each particular cost category, likely legislative changes, changes to our operating environment as well as scope for efficiency savings, we also have had regard to the opex factors in the Rules that the AER must consider in deciding whether it is satisfied that our total forecast opex reasonably reflects the opex criteria. Consideration of the above factors in forecasting future expenditure requirements is a prudent course of action and would be expected if the total forecast opex is to reasonably reflect the opex criteria.

In Attachment 0.03 we have also addressed the opex factors in the Rules that specifically relate to the forecasting process used by a DNSP. In summary:

- We have considered the substitution possibilities between operating and capital expenditure in developing our forecast opex (opex factor 7). A key step in our expenditure forecast process is to consider the full range of alternative options, including areas where there may be opex solutions such as maintenance, which have then been factored into our opex forecasts.
- Endeavour Energy has considered and made provision for efficient and prudent non-network alternatives (opex factor 10). We have investigated ways to defer augmentation at specific sites of our network when developing our forecasts, and have incorporated the expected reduction in system demand from the implementation of new broad based demand management activities. These efficient costs have been incorporated into our opex forecasts.
- We have considered the relative prices of operating and capital inputs (opex factor 6). As noted above we have sought to assess all feasible options when addressing a need including opex and capex

options. When doing so, we have used best practice methods for deriving the relative cost of opex and capex solutions, and have applied a common method for real cost escalation.

- Our expenditure forecast process has considered the concerns of electricity consumers as identified in the course of our engagement with electricity consumers (opex factor 5A). We engaged customers on a range of issues including reliability, price, and demand management. The findings from our customer engagement support the basis of our proposed total opex including in relation to price affordability, and maintaining current levels of safety and reliability.
- Endeavour Energy's forecast method considered whether any opex should be identified as contingent projects, and therefore excluded from the total forecast capex or opex for standard control services (opex factor 9). We found that no component of our opex cost categories met the criteria of a contingent projects set out in 6.6A.1 of the Rules.
- Our forecast process identified that there have been no final project assessment reports at the time of submitting this proposal (opex factor 11).

Indicators to assess the reasonableness of the forecast

Whilst there is no external, observable measure that can be relied upon to demonstrate that the total forecast expenditure is efficient, there are nevertheless partial indicators that assist in confirming the efficient level of the forecast expenditure that was derived from a prudent approach. These factors are stated in the NER and are intended to assist the AER in making a decision on whether the total forecast expenditure reasonably reflects the expenditure criteria.

In Attachment 0.03 we have addressed the remaining opex factors that we consider may represent partial indicators of the efficient level of opex. In this respect, the NER require the AER to give regard to actual and expected operating expenditure during any preceding regulatory control periods (opex factor 5), whether the operating expenditure forecast is consistent with any incentive scheme or schemes (opex factor 8)

Endeavour Energy was subject to the efficiency benefit sharing scheme (EBSS) for the current 2009-14 period. The EBSS provides incentives for business to pursue efficiency improvements in opex and to share efficiency gains with customers. This is demonstrated by the comparison of our actual opex performance against the efficient benchmark set by the AER.

This performance was achieved by the implementation of a number of cost saving initiatives. It has set a solid platform for Endeavour Energy in ensuring that the forecast opex for the 2014-19 reasonably reflects the efficient costs that a prudent operator would need to achieve the opex objectives, taking into account a realistic expectation of demand forecasts and cost inputs.

The AER must also consider the most recent annual benchmarking report and the benchmark capital/operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period (opex factor 4). The purpose of this factor is for the AER to consider whether available benchmarking information can provide a partial indicator of the efficiency of the forecast expenditure, and if so the investigations and weight that should be ascribed to that data. The AER will be releasing its first benchmarking report in September 2014, and therefore we are not provided with an opportunity to demonstrate or make representations on this report at the time of submitting our regulatory proposal.

Endeavour Energy has developed a comprehensive report, Attachment 0.12. The report examines the inherent limitations of benchmarking Australian DNSPs, and the role that benchmarking should play as a partial indicator of efficiency. Our analysis identified that benchmarking has inherent limitations such as inability to conduct 'like for like' analysis across peer firms, data inconsistency and inaccuracy, and failure to meet statistic principles. We think that appropriate benchmarking does have a role in guiding the regulator to areas requiring further granular analysis. It should not be used to reject a DNSP's proposal, or as a basis to substitute the forecast given the inherent limitations as a tool. In the report we also:

- Assessed the relative weight that should be applied to each of the benchmarking tools identified by the AER in its Forecast Expenditure Assessment Guidelines including economic analysis, aggregated category analysis, and cost category data. When deciding if a benchmark is appropriate, we have been guided by the Productivity Commission's review in 2013 which set out six criteria for when a benchmarking tool could be used in the process.

- Sought to understand the available data that can be used for benchmarking and reported on these outcomes. This was based on a Huegin Consulting study of seven DNSPs in Australia. The Huegin study demonstrates that benchmarking is of limited value due to its inherent limitations, and that measures of efficiency more closely relate to the characteristics of the business rather than managerial decisions. Despite this, Huegin's report does provide some basis to show that Endeavour Energy is efficient relative to other peers in the study group. Refer to Attachment 0.11.

Based on this approach, we have placed limited weight on benchmarking analysis as a valid test of the efficiency of our forecast and consider that the AER should do likewise in its assessment. Our analysis of benchmarking tools suggests that trends in a DNSP's results over time is of more value than relative efficiencies between DNSPs at a point in time.

The final factor we have considered as a partial indicator of efficiency is the extent the operating expenditure forecast is referable to arrangements with another person that do not reflect arm's length terms (opex factor 9). We confirm that our forecast opex for 2014-19 does not include any arrangement with any other person that do not reflect arm's length terms.

7 ALLOWED RATE OF RETURN

Summary

We propose a rate of return on capital of 8.83 % that promotes long-term stability for customers and equity holders, as well as debt financiers. A long-term approach achieves what should be a fundamental objective of the regulatory framework - to minimise the impact of short-term volatility in financial markets when calculating the allowed rate of return.This is in the interests of both consumers and regulated businesses.

In this chapter, we provide further information on the basis of our proposed rate of return on capital. Our proposed approach has considered the AER's final rate of return guideline. Where we have departed from the methods set out in the rate of return guidelines, we explain our reasons for departure.[70] Our key contentions are as follows:

- We propose a rate of return of 8.83%, which is commensurate with the minimum efficient financing costs for a DNSP with a similar degree of risk as that which applies to Endeavour Energy over the 2014-19 regulatory period. The proposed rate of return has been developed to promote long-term stability both for customers and equity holders.'
- Our proposed rate of return approach for setting both the allowed cost of debt and the allowed equity would provide return profiles commensurate with what is required to attract investment in long-lived electricity network assets. This is essential because investors want stable and predictable returns over the long term to be able to invest in such long lived infrastructure assets.
- We propose an allowed cost of debt of 7.98%, which has been calculated consistent with the 10-year trailing average approach set out in the AER's final rate of return guideline. This estimate is based on bond yield data for BBB+ and BBB rated Australian corporate bonds issued from 1 January 2004 to 31 December 2013.
- Consistent with the AER's final rate of return guideline, we agree that the cost of debt should be subject to annual updates throughout the regulatory period.
- We have serious concerns with the AER's proposed 10 year transition path to the trailing average. As Endeavour Energy has historically issued debt on a benchmark efficient staggered portfolio basis, the AER's debt transition would significantly under compensate Endeavour Energy based on current forecasts of yields on 10 year BBB corporate bonds. We consider that the application of the AER's proposed debt transition would not allow us the opportunity to recover at least our efficient costs of debt finance, which is inconsistent with the revenue and pricing principles outlined in section 7A of the National Electricity Law and should be applied to Endeavour Energy.
- The AER's proposed transition path would mean that the benchmark efficient approach for setting the allowed cost of debt (the trailing average approach) would not be fully implemented for 10 years, i.e. not until the 2024-29 regulatory period. We consider that a debt transition that is not fully unwound until 1 July 2024 is not reasonable for firms that already issue debt on a staggered portfolio basis. If the AER applied its proposed transition to firms that issue on a staggered portfolio basis, it would be setting revenue allowances on an inefficient basis and providing incentives inconsistent with the benchmark efficient approach to debt portfolio management.
- We propose an allowed cost of equity of 10.11%, which has been estimated using internally consistent estimates of parameters within the capital asset pricing model (CAPM). The cost of equity is at the lower end of a reasonable range that takes into account prevailing market conditions and

[70] As required by schedule 6.1.3(9)

evidence from relevant financial models including the CAPM, the dividend growth model (DGM), the Fama-French 3 Factor Model (FFM), and the Black CAPM.

Overall rate of return

The NSW DNSPs have consistently advocated a return on capital that is based on long-term observations of financial market data and that takes account of prevailing conditions in the market for funds. This approach minimises the impact of short-term volatility in financial markets (that would not be expected to prevail over a regulatory period) on regulated revenues and consequently consumer prices over time. Our proposed rate of return incorporates the following:

- A 10 year trailing average approach with annual updates for setting the return on debt, which the AER has recognised is commensurate with the staggered portfolio approach that is the most efficient and stable approach in the presence of refinancing risks.[71] Annual updates also ensure that changes in debt costs can be gradually incorporated into consumer prices rather than through price shocks between regulatory periods.
- A long-term approach to setting the allowed return on equity, which provides efficient and stable returns to equity holders. The long-term estimate has been considered in the context of prevailing market conditions to ensure that the allowed return on equity is commensurate with the benchmark efficient costs of raising equity finance for long-lived infrastructure assets over the 2014-19 regulatory period.

Our proposed rate of return has been developed to meet the requirements of the Rules to contribute to the achievement of the national electricity objective set out in section 7 of the NEL, and to be consistent with the Revenue and Pricing Principles set out in section 7A of the NEL. In particular, clause 6.5.2(c) of the Rules requires that the rate of return must achieve the allowed rate of return objective, which is that:

> *the rate of return for a Distribution Network Service Provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the Distribution Network Service Provider in respect of the provision of standard control services (the allowed rate of return objective).*

As set out above, our proposed rate of return has been developed to be commensurate with the efficient financing costs of a benchmark entity with a similar degree of risk as that which applies to Endeavour Energy in providing standard control services.

In setting the allowed rate of return, clause 6.5.2(e) of the Rules also require that the AER must have regard to:

(1) relevant estimation methods, financial models, market data and other evidence;

(2) the desirability of using an approach that leads to the consistent application of any estimates of financial parameters that are relevant to the estimates of, and that are common to, the return on equity and the return on debt; and

(3) any interrelationships between estimates of financial parameters that are relevant to the estimates of the return on equity and the return on debt.

Consistent with the Rule requirements, we propose a rate of return of 8.83%. Our proposed rate of return is commensurate with the minimum efficient financing costs for a DNSP with a similar degree of risk as that which applies to Endeavour Energy over the 2014-19 regulatory period.[72]

[71] AER, Explanatory statement on the rate of return guideline, December 2013, p. 23.

[72] As required by clause 6.5.2(c) of the NER.

7 ALLOWED RATE OF RETURN

The cost of debt has been estimated using a 10 year trailing average approach that will be subject to annual updates throughout the regulatory control period. We propose an automatic approach to annually updating the cost of debt using data published by the Reserve Bank of Australia (this is outlined below). We note that we have serious concerns over the AER's proposed approach of adopting a transition to the trailing average because it varies significantly from the return on debt required by a benchmark efficiency entity facing similar risks as Endeavour Energy. This transition exposes Endeavour Energy and our customers to undesirable volatility and risk. The transition would, if implemented when rates remain at current levels, significantly under-compensate Endeavour Energy if interest rates remain at current levels.

If the AER was to apply a transition to the trailing average for Endeavour Energy, we would likely be provided with an allowed return on debt lower than our efficient cost of debt. This is not consistent with the allowed rate of return objective, the Revenue and Pricing Principles or the national electricity objective, which requires that a network service provider be provided with a reasonable opportunity to recover at least its efficient costs so as to promote the efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity.

The cost of equity has been estimated using internally consistent estimates of parameters within the CAPM. The cost of equity is at the lower end of reasonable ranges taking into account prevailing market conditions[73] and evidence from relevant financial models including the CAPM, the dividend growth model (DGM), and the Fama-French 3 Factor Model (FFM).[74] The breakdown of our proposed rate of return is outlined in Table 33 below.

Our proposed rate of return has been informed by leading financial and economic experts and we have attached a number of expert reports in support of our position. Additional details on Endeavour Energy's approach to the rate of return are set out in a report from CEG titled 'WACC Estimates, a report for NSW DNSPs" which is attached to this regulatory proposal. We note that the CEG report references an extensive number of relevant documents and expert reports, which are provided for completeness as attachments to this proposal.

Table 33: Indicative range of rate of return and proposed rate of return

Rate of return parameters	Proposed WACC %	Reasonable range of estimates - %
Overall WACC	**8.83%**	**8.83% - 9.44%**
Cost of equity	10.11%	10.11% - 11.50%
Cost of debt	7.98%	7.98% - 8.06%
Gearing	60%	60%
Utilisation of imputation	25%	25%

[73] As required by clause 6.5.2(g) of the NER.

[74] As required by clause 6.5.2(e)(1) of the NER.

7 ALLOWED RATE OF RETURN

Cost of debt

Endeavour Energy proposes a trailing average cost of debt allowance of 7.98% using yields on 10 year BBB+ and BBB rated Australian corporate bonds over the past 10 years.

Throughout the development of its rate of return guideline, the AER has recognised that in the presence of re-financing risk, the benchmark efficient practice is to issue debt on a staggered portfolio basis.[75] A trailing average estimate reflects the cost of debt for a benchmark efficient entity that has issued debt on a staggered portfolio basis. As a result, in its final rate of return guidelines the AER proposed to estimate the allowed return on debt for energy network firms using a trailing average approach.[76] We agree that the allowed return on debt should be estimated using a trailing average approach.

Endeavour Energy proposes a trailing average return on debt allowance using yields on 10 year BBB+ and BBB rated Australian corporate bonds over the past 10 years. This reflects the benchmark efficient costs of debt for a firm that has issued Australian corporate debt on a staggered portfolio basis over the past 10 years. We propose a 7.98% trailing average cost of debt, which is based on the following:

- An immediate application of the 10 year trailing average approach without any transition.
- Australian corporate bond yield data from the Reserve Bank of Australia (RBA) for the nine year period from 1 January 2005 to 31 December 2013.
- Bloomberg data for the one year period from 1 January 2004 to 31 December 2004. We have used Bloomberg data for this period because the RBA has not published corporate bond yield data prior to January 2005. Using Bloomberg data allows us to calculate a proper 10 year trailing average.
- Consistent with market data for listed energy firms, an assumption that the benchmark entity has a BBB+ rating up to 2008 and a BBB rating from 2009 onward. The sample of energy firms used to determine this assumption is the same sample of firms used by the AER sample to determine the benchmark efficient credit rating for energy network firms.
- An extrapolation of the RBA curve to an effective tenor of 10 years, which is necessary to achieve a 10 year trailing average, since the RBA forecast has an effective tenor shorter than 10 years (approximately 8.7 years for BBB rated debt and 8.9 years for A rated debt).

The data and calculations are outlined in further detail in a report by CEG titled “WACC estimates”, which is attached with this proposal. Here we note that the 2004 Bloomberg data would only be used in the calculation of the trailing average for 2014-15 as it would ‘roll-of’ and be replaced by data contained in the RBA data set from 1 January 2005 (i.e. for the calculation of the 2015-16 trailing average) onwards.

Credit rating

The AER’s rate of return guideline sets a BBB+ benchmark credit rating based on the median credit rating for a sample of regulated Australian utilities over the period 2002 to 2012. The AER does not provide the basis for its calculation. However, CEG has replicated the AER’s analysis and determined that up to the end of 2008 the benchmark credit rating for the AER’s sample is BBB+, but from 2009 onwards there has been a sustained drop in median credit ratings for the AER’s benchmark to BBB. This is illustrated in the table below.

[75] AER, Explanatory statement, Rate of return guideline, December 2013, pp. 104-105.

[76] AER, Final rate of return guideline, December 2013, section 6.3.1, p. 19.

7 ALLOWED RATE OF RETURN

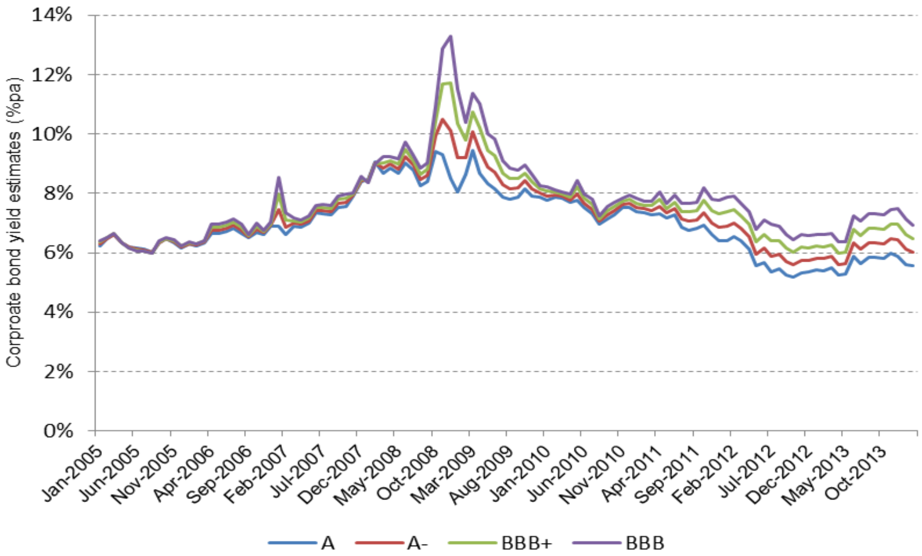
Table 34: Median credit rating for AER sample by year

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
A-	BBB+	BBB+	BBB+	BBB+	BBB+	A-	BBB	BBB	BBB	BBB	BBB

Source: Bloomberg, CEG analysis

The impact of the credit rating assumed can have a material impact on the cost of debt as illustrated in Figure 21 below, which provides the full time series of RBA data used to calculate the trailing average from 1 January 2005 to 30 December 2013.

Figure 21: Time series of RBA cost of debt by credit rating



Source: RBA, CEG analysis, A -/BBB+ is calculated as 2/3 weight A/BBB and 1/3 weight to BBB/A-

As illustrated above, varying the benchmark credit rating in 2008 and earlier does not have a material impact on estimated average yields. It is only in 2009 and onwards that there is a significant departure in the cost of debt between the different credit ratings.

Given that the median credit rating of the sample used to derive the AER's benchmark credit rating since 2009 is BBB, it is appropriate that a BBB+ credit rating is applied up to 2008, with a BBB credit rating from 2009 onwards as this represents the benchmark efficient firm. Applying the AER's BBB+ credit rating is not consistent with the available data set for determining the benchmark efficient firm and would under-compensate Endeavour Energy.

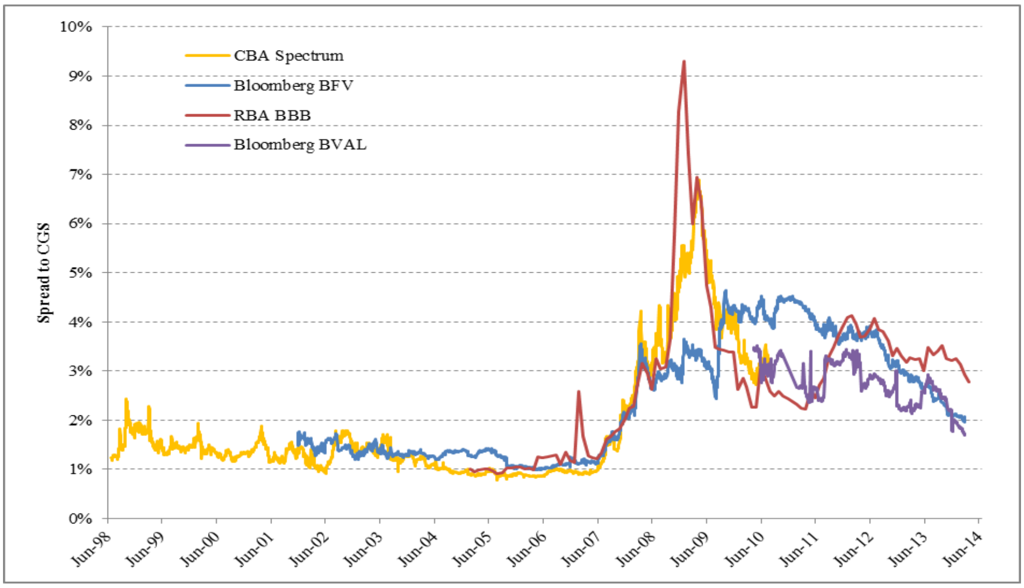
Endeavour Energy considers that it is appropriate to hold this benchmark credit rating constant for the five years of this regulatory period – an approach which is consistent with the view that the benchmark only changes gradually. However, an alternative approach would be to calculate the median credit rating of the AER sample in the middle of each new averaging period (calendar year) using the methodology set out in CEG's report "WACC estimates, a report for the NSW DNSPs" attached to this regulatory proposal.

The trailing average approach

A trailing average cost of debt would ensure that customer prices are not exposed to short term movements in financial markets that could significantly raise or lower the allowed cost of debt if it were set using observations of bond yields over a short 20 business day period. In addition, a trailing average cost of debt provides appropriate incentives for energy network firms to issue debt on a staggered portfolio basis, which minimises refinancing risks and allows businesses to more effectively manage the risk of mismatch between the regulated cost of debt and the actual costs of debt (interest rate mismatch risk).

The previous Rules required the AER to use a short-term averaging period approach when setting the allowed cost of debt. The short-term averaging period was intended to smooth out daily variability in corporate bond yields. However, the previous Rules were conceived without proper regard to the efficient practices of businesses and the potential volatility in corporate debt costs over time. Following the global financial crises, corporate bond yields became much more variable over short periods as demonstrated in the graph below – demonstrating that a short-term averaging period cannot be presumed to be sufficient to smooth variability in corporate bond yields over time.

Figure 22: Corporate bond spreads to 10 year CGS yields



Source: CEG, WACC estimates, a report for NSW DNSPs, May 2014.

Under the previous short-term averaging period approach, some businesses may have attempted to manage interest rate mismatch risk in a number of ways (e.g. by issuing significant tranches of debt over their nominated[77] short-term averaging period, by issuing callable debt or by using hedging instruments to match a large component of actual interest costs to the allowed cost of debt). While these practices may have mitigated some (but not all) of the interest rate mismatch risk, each practice would expose a businesses to significant refinancing risks.[78] These risks included that:

- the business could be forced to access debt/hedging markets at times that were generally or specifically unfavorable for the business; and/or
- the business would have to access debt/hedging markets in such large quantities relative to demand that the proposed transactions would move market prices against the business.

This meant that the actual cost of debt incurred by a business pursuing these (partial) hedging strategies could be expected to be higher than the efficient cost of debt on average. It also meant that the regulatory allowance could be well above or below both the efficient cost of debt and any given business's actual (partially) hedged cost of debt.

[77] Nominated at the time of a regulatory decision.

[78] This risk was recognised by the AER during its rate of return guidelines process. See AER, Explanatory statement, Rate of Return Guideline, December 2013, pp. 104-104.

A trailing average approach would have ensured more stable debt allowances (and customer prices) over time. It would also reduce the potential for measurement error to affect the regulatory allowance. The potential for measurement errors is illustrated by the periods when Bloomberg and RBA/CBASpectrum estimates departed from each other significantly. Under the trailing average approacht debt costs in any individual period would be given a small weight in the trailing average allowance and will tend to offset each other provided that estimation error is not systematic in one or the other direction.

Inefficiency of trying to manage debt using the previous "on the day" approach

The explanatory statement to the final rate of return guideline stated that it was open to regulated energy network firms to match interest costs with the short term averaging period approach by either:

- re-issuing all debt over one short term averaging period every five years (a natural hedge); or
- using derivatives instruments to match actual debt costs with cost of corporate debt issued over a short term averaging period (a synthetic hedge).[79]

However, given the significant size of Endeavour Energy's debt portfolio, it would have been costly and imprudent to have managed interest rate risk by issuing significant tranches of debt during the nominated short term averaging period. Given that Endeavour Energy's benchmark debt portfolio was approximately $3.3 billion in 2009, the refinancing risk would simply have been too great for Endeavour Energy to expose itself to in the face of short term variability in financial markets. We note that in the face of the Global Financial Crisis (GFC) Endeavour Energy would have been refinancing its entire debt portfolio to match the regulatory allowance. Clearly this refinancing would not have been possible at a time when the Australian corporate bond market had all but dried up.

Similarly, if attempting to use interest rate swaps, Endeavour Energy would have been attempting to lock in a 5 year base rate on its entire debt portfolio at a time of great dislocation in financial markets. This is illustrated by the fact that the spread between 5 year swaps and CGS was at historic high levels (around 120bp per annum compared to pre GFC levels of a little over 40bp per annum).[80] It is unclear whether large scale interest rate swap transactions at this time would have been possible let alone prudent.

Endeavour Energy's benchmark debt portfolio is estimated to be approximately $5.6 billion by 30 June 2014 (for standard control services alone) and it remains costly and imprudent for Endeavour Energy to attempt to match its actual debt costs with the regulatory allowance under a short term averaging period and transition approach. Confidential advice received from UBS that is attached with this regulatory proposal provided to the AER outlined that given the depth of the interest rate derivative market there is a real risk that Endeavour Energy would not be able to hedge the cost of debt allowance using interest rate swaps. The UBS advice also demonstrates that even if Endeavour Energy was able to refinance its entire debt portfolio over a short-term averaging period or use interest rate swaps to match its actual costs to yields observed over a short term averaging period, the pricing of the debt would not be efficient and would come at a significant cost to Endeavour Energy. [81]

Therefore, a short-term averaging period approach reflects a clearly inefficient approach to managing debt for a benchmark efficient DNSP with a notional debt portfolio the size of Endeavour Energy's. Endeavour Energy therefore supports the adoption of the trailing average approach to estimating the return on debt.

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[80] CEG, WACC estimates, May 2014.
[81] UBS, Advice to Networks NSW, October 2013 [Confidential]

7 ALLOWED RATE OF RETURN

Transitional arrangements for the cost of debt

In its final rate of return guidelines, the AER stated that the return on debt will be estimated using a 10 trailing average debt portfolio approach[82] after a transitional period. The AER's final rate of return guideline proposes to apply a transition to the trailing average approach to all service providers. We agree with the adoption of a 10 year trailing average approach, but we do not agree with the AER's proposed transition.

We consider that the AER's proposed transition approach will not contribute to the achievement of the national electricity objective, is inconsistent with the revenue and pricing principles and the provisions of the NER. Moreover, we do not consider that the final rate of return guideline has properly considered joint NSW DNSP submissions on the proposed transitional approach to setting the cost of debt and its application to the NSW distribution businesses, including Endeavour Energy.[83]

The rate of return guideline sets out the methods the AER proposes to use in estimating the allowed rate of return for distribution determinations. The guideline is not binding on the AER in making a distribution determination, neither is it binding on a DNSP in developing its regulatory proposal. However, schedule 6.1.3(9) of the Rules requires a DNSP to explain its reasons for departing from the rate of return guideline if it chooses to do so. In this section we set our reasons for departure from the transitional approach to setting the cost of debt set out in the final rate of return guideline. Detailed reasons for our departure from the proposed transition approach outlined in the AER's final rate of guideline are elaborated by CEG in its report titled "Debt transition consistent with the NER and NEL." CEG's report is attached with this regulatory proposal.

Inconsistency with the revenue and pricing principles

The revenue and pricing principles set out in section 7A of the NEL provide that a service provider should be provided with **a reasonable opportunity to recover at least the efficient costs** the operator incurs in providing direct control network services, and complying with a regulatory obligation or requirement or making a regulatory payment.[84]

Section 7A sets out the revenue and pricing principles in detail:

> *(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—*
>
> > *(a) providing direct control network services; and*
> >
> > *(b) complying with a regulatory obligation or requirement or making a regulatory payment.*
>
> *(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—*
>
> > *a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and*
> >
> > *b) the efficient provision of electricity network services; and*
> >
> > *c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.*

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[82] That is, the average return that would have been required by debt investors in a benchmark efficient entity if it raised debt over an historical period prior to the commencement of a regulatory year in the regulatory control period. See AER, Explanatory Statement, Final rate of return guideline, December 2013, p. 73.
[83] See NSW DNSPs, Submission on AER rate of return consultation paper, 21 June 2014 and NSW DNSPs, Submission on AER draft rate of return guideline, 11 October 2013.

[84] S 7A(2) of the NEL.

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

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

The AER must take into account the revenue and pricing principles when making a distribution determination.

The AER has determined that the efficient financing practice of a benchmark efficient entity is to issue debt on a staggered basis consistent with the trailing average approach. The transitional approach of the AER proposes to preclude consideration of the individual circumstances (i.e. the current debt structure) of the service providers. This means that it is not relevant that some service providers may already structure their debt in an efficient manner consistent with the trailing average and therefore do not require transitional arrangements. Indeed, the application of the arrangements to all service providers has the effect that some service providers such as Endeavour Energy may be under-compensated for their costs of debt, as the formula applied to determine the cost of debt assumes that a benchmark efficient entity does not structure its debt in an efficient manner.

Under the AER's proposed transition to the trailing average, the AER would set the allowed cost of debt for the first year of the next regulatory period (2014-15) based on observations of corporate bond yields over a prospective, short term averaging period that is close to the time of a final network determination. For the second regulatory year (2015-16), 90% weight would be given to the observed cost of debt over 2014-15 and thereafter each year the initial observation would be given 10% less weight and each new year of data would be given 10% weight in the allowed cost of debt for that regulatory year. It is only in the tenth year that the transition is complete and each year has an equal 10% weighting in the trailing average calculation.

This approach exposes Endeavour Energy to significant risk because only a small fraction, less than 10%, of an efficient benchmark DNSP's debt portfolio (and indeed less than 10% of Endeavour Energy's total debt portfolio) will be refinanced between January and December 2013, in the lead up to 2014-15. Even less would be re-financed over a 20 business day period. Consequently, debt market conditions in this period would affect less than 10% of a benchmark efficient DNSP's (and in this case, Endeavour Energy's) debt portfolio for a period of around 10 years. By contrast, the AER's transition allowance will give this same period 100% weight in 2014-15 and 90% weight in the next year and so on until this period drops out of the AER's cost of debt allowance in 10 years. The effect of this is that over the next 10 years this period will have 55% weight in the AER's allowance.

This is even more than the 50% weight that the same period would have been given under the previous approach (100% weight in the first of two averaging periods over 10 years and 0% weight in the second). In this sense, over the next 10 years, the AER transition actually compounds rather than alleviates the mismatch problems associated with the former 'on the day' approach.

This exposes Endeavour Energy to significant mismatch risk arising from differences in market conditions under which it has actually raised its debt and the market conditions under which the AER transition allowance assumes debt was raised. It also exposes Endeavour Energy to significant risk of measurement error. By giving such high weight to the short term averaging period, the AER's transitional allowance will be materially impacted by any measurement error in that period and that impact will be long lasting. By contrast, under immediate adoption of a trailing average as proposed by Endeavour Energy each individual month receives less than 1% weight in the cost of debt allowance – such that any unbiased measurement error will largely cancel out over the full period used to estimate the trailing average. The heightened measurement error associated with the AER's transition approach has been implicitly recognised by the AER.[85]

[85] AER, Explanatory statement, Final rate of return guideline, December 2013, p. 110.

The AER transition approach means that service providers such as Endeavour Energy will be under-compensated to the extent that spot rates for the cost of debt are at levels below trailing average estimates (and vice versa). The rate of return guideline (if adopted by the AER in making a revenue determination) may have the effect of denying Endeavour Energy and others a reasonable opportunity to recover their efficient financing costs, contrary to the revenue and pricing principles. We note that the opportunity to recover costs has been recognised as a crucial factor in the achievement of the national electricity objective (see reference below to the Australian Competition Tribunal's decision in EnergyAustralia and Others [2009]).

In addition, the transition mechanism actively encourages Endeavour Energy to move away from the approach to financing that the AER has concluded is efficient (the use of a trailing average). To hedge to the regulatory cost of debt under the AER's transition approach Endeavour Energy would have to enter into swaps and/or hedges for its already issued debt in order to manage the interest rate risk from the on the day approach to the extent possible. In determining the efficient financing practice of the benchmark efficient entity, the AER implicitly concluded that these swap and hedge contracts were inefficient. Encouraging Endeavour Energy to enter into these inefficient arrangements when it is already efficient is inconsistent with section 7A(3) of the NEL.

Finally, any under-recovery of Endeavour Energy's efficient costs may lead to inefficient under-investment in distribution networks given that the under-recovery will be reflected in the revenue that Endeavour Energy may earn (and the prices that Endeavour Energy may charge). The potential consequences of under-investment Endeavour Energy's distribution networks is significant given security of supply risks and the importance of electricity supply to consumers. Having regard to these issues as required by sections 7A(6) and (7) of the NEL, emphasises the need for Endeavour Energy to be able to recover at least its efficient costs of providing the services, which will not be achieved if the transition is applied.

Will not, and is not likely to, contribute to the achievement of the national electricity objective

The NEL sets out that the AER must perform or exercise and AER economic regulatory function or powers in a manner that will or is likely to contribute to the achievement of the national electricity objective.[86] The national electricity objective is defined in section 7 of the NEL:

> *to promote efficient investment in, and efficient operation and use of, electricity services for the long term interest 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.*

The making of a distribution determination is an AER economic regulatory function or power conferred on the AER by the NER.

Imposing transitional arrangements which do not allow service providers the opportunity to recover their efficient costs and potentially dis-incentivises investment is contrary to the national electricity objective. The Australian Competition Tribunal (Tribunal) has considered the importance of a service provider being provided with the opportunity to recover at least their efficient costs of investment.

> *The national electricity objective provides the overarching economic objective for regulation under the NEL: the promotion of efficient investment and efficient operation and use of, electricity services for the long term interests of consumers. Consumers will benefit in the long run if resources are used efficiently, that is if resources are allocated to the delivery of goods and services in accordance with*

[86] S 16 of the NEL.

consumer preferences at least cost. As reflected in the revenue and pricing principles, this in turn requires prices to reflect the long run cost of supply and to support efficient investment, providing investors with a return which covers the opportunity cost of capital required to deliver the services.[87]

…

It might be asked why the NEL principles require that the regulated NSP be provided with the opportunity to recover at least its efficient costs. Why 'at least'? The issue of opportunity is critical to the answer. The regulatory framework does not guarantee recovery of costs, efficient or otherwise. Many events and circumstances, all characterised by various uncertainties, intervene between the ex ante regulatory setting of prices and the ex post assessment of whether costs were recovered. But if, as it were, at the outset the regulator did not provide the opportunity for a DNSP to recover its efficient costs (e.g., by making insufficient provision for its operating costs or its cost of capital), then the NSP will not have the incentives to achieve the efficiency objectives, the achievement of which is the purpose of the regulatory regime.[88]

It is evident that the Tribunal considers that providing service providers with the opportunity to recover efficient costs is crucial to the functioning of the regime. The adoption of transition arrangements which substantially delay the implementation of the trailing average approach effectively defers the opportunity to recover "efficient costs" while at the same time penalising Endeavour Energy for being efficient and encouraging the adoption of inefficient financing practices during the short term. The transition does this because it fails to take into account the risks faced by Endeavour Energy as a result of the application of the transition would be contrary to the national electricity objective.

Further, we consider that the transitional approach does not encourage efficient investment practices because it prescribes a rate of return that is likely to "punish" those service providers who have already structured their debt in an efficient way by not allowing them to recover their efficient costs of debt.

Inconsistency with the provisions of the NER

Section 6.5.2(c) of the Rules requires the AER to determine an allowed rate of return that achieves the allowed rate of return objective at the time of the determination. The allowed rate of return objective is:

…that the rate of return … is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the [service provider] in respect of the provision of [regulated services].[89]

The return on debt forms part of this allowed rate of return. The AER must estimate the return on debt such that it contributes to the achievement of the allowed rate of return objective. Endeavour Energy does not consider that the application of the transition to it will result in an estimate of the return on debt that contributes to the achievement of the rate of return objective or complies with the provisions of the NER for the reasons discussed in this section.

Delay in achieving the allowed rate of return objective

The adoption of the AER's cost of debt transition is contrary to the rate of return objective precisely because it significantly delays the adoption of the 10 year trailing average approach to determining the cost of debt, which the AER has determined is consistent with the rate of return objective. This is clear from the AER's Explanatory Statement to the final rate of return guideline in which the AER stated:

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[87] *Application by EnergyAustralia and Others* [2009] ACompT 8 (12 November 2009) (**EnergyAustralia and Others**),   [18].

[88] EnergyAustralia and Others, [81].

[89] Rule 6.5.2(c)

7 ALLOWED RATE OF RETURN

> *Our preferred approach to estimation of allowed return on debt is the trailing average portfolio approach. ….In the presence of refinancing risk, it is efficient for a service provider to hold a portfolio of debt with staggered maturity dates. The allowed return on debt under the trailing average portfolio approach reflects the financing cost of a benchmark efficient entity with such a staggered portfolio.*[90]

We note that Clause 6.2.8(d) of the Rules requires that where any guideline published by the AER indicates that there may be a change of regulatory approach in future distribution determinations, the guideline should also (if practicable) indicate how transitional issues are to be dealt with. For the cost of debt, neither Endeavour Energy nor its customers would be subject to adverse outcomes by moving to the 10 year trailing average approach. This has been noted in consumer advocacy group submissions to the AER.[91] For example, in response to the AER's rate of return consultation paper, the Energy Users' Association of Australia (EUAA) submitted that:

> *If the reason for changing the arrangements for the return on debt is that the current arrangement is flawed, and that a rolling average is a better solution (both propositions now widely accepted) how can any change resulting from the correction of a flawed arrangement be "undue" or "sub-optimal", and hence deserving of a transition arrangement?*[92]

Throughout the rate of return guideline consultation process, we have noted in joint NSW DNSP submissions to the AER that we have prudently managed refinancing risks over the past 10 years by issuing debt on a staggered portfolio basis. Endeavour Energy maintained this efficient debt management approach despite the previous cost of debt rules, which mandated that the cost of debt be set based on a short term averaging period.

Therefore, we do not face the transitional issues that may face network service providers that were able to re-finance large portions of their total debt portfolios (either directly or through derivative instruments) to match the allowed cost of debt under the short term averaging period approach.

The AER's Explanatory Statement to the rate of return guideline clearly demonstrates that the AER agrees that it would not be efficient to attempt to issue 100% of all debt in such a narrow window.[93] Therefore, the AER's justification for the beginning point of its transition (which is the 'on the day' approach) must rely on the belief that businesses can match their costs to the 'on the day' approach using swap contracts. Indeed, the explanatory statement explicitly states:

> *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 [the] 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.*[94] *[Emphasis added.]*

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[90] AER, Explanatory statement, Final rate of return guideline, December 2013.

[91] See summary of consumer group submissions in NNSW, Submission to AER draft guideline, 11 October 2013, p. 8.

[92] EUAA, Submission on rate of return consultation paper, p. 15.

[93] This is, of course, borne out by the fact that the AER moved away from an allowance that was based on 100% debt refinancing at the beginning of the regulatory period. It is also consistent with other statements made in the December explanatory statement to the Guidelines such as "Thus, we consider that holding a (fixed rate) debt portfolio with staggered maturity dates to align its return on debt with the regulatory return on debt allowance is likely to be an efficient debt financing practice of the benchmark efficient entity under the trailing average portfolio approach" (p. 109).

For an Australian efficient operator there is no market to effectively, and in a cost efficient manner, hedge their DRP. Pg 105

P 109

[94] AER, Dec 2013, p. 107.

Definition of the benchmark efficient entity

The AER appears to be proposing a definition of the benchmark efficient entity as one who uses interest rate swaps to align the resetting of base interest rates to the beginning of the regulatory period. The benchmark efficient entity described in the allowed rate of return objective must be a:

> *benchmark efficient entity with a similar degree of risk as that which applies to the [service provider] in respect of the provision of [regulated services]*

Consistent with the advice from UBS, Endeavour Energy believes that any attempt to use swap contracts in the manner described would have resulted in both the risk of an inefficiently high cost of debt and a risk that Endeavour Energy would not be able to hedge all of its debt. The transition proposed by the AER in the rate of return guidelines is based on a benchmark efficient entity that responds in a particular way to the specific rules of the regulatory regime and fails to consider the risks faced by Endeavour Energy. A transition based on this benchmark efficient entity cannot result in an estimate of the return on debt when it is applied to a Endeavour Energy, particularly one that faces risks faced by Endeavour Energy.

The AER's ultimate adoption of a trailing average benchmark and not a hybrid benchmark (staggered debt issuance with an interest rate swap overlay) is tacit support for this position.

Impact from the change in methodology

When estimating a return on debt such that it contributes to the achievement of the allowed rate of return objective, section 6.5.2(k)(4) of the Rules requires the AER to have regard to:

> *any impacts (including in relation to the costs of servicing debt across regulatory control periods) on a benchmark efficient entity referred to in the allowed rate of return objective that could arise as a result of changing the methodology that is used to estimate the return on debt from one regulatory control period to the next.*[95]

This indicates that the AER must consider whether changing the methodology for estimating the return on debt would have any impact on "a benchmark efficient entity". It is important to understand that this factor is directed to any potential impact on the benchmark efficient entity. Therefore it anticipates that there may be circumstances in which a change in methodology to be applied in a distribution determination (as compared to the methodology that was applied in the preceding determination) may adversely affect a benchmark efficient entity. This is consistent with the revenue and pricing principles, the application of which would require that a service provider receives "at least" its efficient costs which may include costs that would be incurred by a benchmark efficient entity as a result of a change in methodology for estimating the return on debt under the NER.

However, putting the above aside, even if the AER could reasonably characterise the current efficient benchmark debt management strategy for Endeavour Energy as:

> *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.*

Then any transition designed to start with this practice would not begin by giving 100% weight to an 'on the day' estimate of the cost of debt. Rather, it would start with the cost of debt associated with this strategy which would need to compensate for the historical average DRP. This is consistent with the AER's own acceptance that:

> *For an Australian efficient operator there is no market to effectively, and in a cost efficient manner, hedge their DRP.*

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[95] Rule 6.5.2(k)(1) and (4).

> *Therefore the benchmark efficient entity would not able to alleviate all potential mismatch in relation to the debt margin component of the return on debt, unless it issues the entirety of its debt during the averaging period. To this extent, under the 'on the day' approach the benchmark efficient entity faces a potential trade–off between the need to manage its refinancing and interest rate risk.*[96]

Therefore, even if one did accept that the AER's proposition that "*and using swap transactions to hedge interest rate exposure for the duration of a regulatory control period"* was efficient under the previous 'on the day' approach this does not provide a justification for the AER adopting the 'on the day' approach as the starting point for its transition.

Moreover, the starting point for the transition would need to include transaction costs associated with operating in swap markets – including the costs associated with (hypothetical) large transactions for NSW DNSPs moving the observed market prices. Such costs were not included in Endeavour Energy's efficient financing costs in its last distribution determination. Endeavour Energy does not consider that these costs can now be assumed to have been borne by the benchmark efficient entity because the impacts which must be considered under this clause are the impacts from changing from the methodology applied at Endeavour Energy's previous distribution determination and the AER's definition of the benchmark efficient practice at that determination. It is clear from the AER's 2009-14 final decision for the NSW DNSPs that the costs of engaging in interest rate swap transactions were not taken into account when setting benchmark efficient debt costs.[97]

In any event, the risks that are faced by Endeavour Energy mean that the benchmark efficient entity is not able to enter into hedging arrangements to manage its interest risk under the on the day approach. It is therefore an inappropriate starting point for the transition and would result in an estimate of the return on debt that does not contribute to the achievement of the allowed rate of return objective.

Potential under compensation with a debt transition

Based on current forecasts of yields on 10 year BBB corporate bonds (extrapolated to 10 years and annualised), the AER's transitional approach to setting the cost of debt would significantly under compensate Endeavour Energy relative to its stand-alone benchmark efficient costs of debt as illustrated in the tables below. The application of the AER's proposed debt transition would not allow us the opportunity to recover at least our efficient costs of debt finance which is inconsistent with the revenue and pricing principles outlined in section 7A of the National Electricity Law.

Table 35: Endeavour Energy's benchmark efficient debt cost v AER transitional cost of debt (% per annum)

	2014-15	2015-16	2016-17	2017-18	2018-19	Average
Benchmark efficient cost of debt	7.98%	7.88%	7.77%	7.67%	7.56%	7.77%
AER transition cost of debt	6.93%	6.93%	6.93%	6.93%	6.93%	6.93%
Difference	-1.05%	-0.95%	-0.84%	-0.74%	-0.63%	-0.84%

Note: Assuming the AER adopts the RBA's estimated BBB cost of debt in April 2014 (extrapolating to 10 years effective term to maturity and annualising) and that future rates continue to remain at current levels

[96] AER, Explanatory Statement, Rate of Return guideline, Dec 2013, p. 105. This first sentence in this extract is a quote from the AER's adviser, Chairmont consulting.

[97] AER, NSW DNSPs final decision, 2009-14 distribution determinations, May 2014, p. 232.

Table 36: Endeavour Energy's potential under compensation

$ Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Benchmark debt portfolio	3,356	3,589	3,776	3,932	4,099	
Under compensation	35	38	40	42	44	198

Note: Benchmark debt portfolio assumes 60% gearing on Endeavour's forecast RAB over the 2014-19 period.

Minimising the difference between the allowed return on debt and that of a benchmark efficient entity

As demonstrated above, the AER's transitional approach would mean that Endeavour Energy would not be provided sufficient regulatory revenues to compensate for the efficient staggered portfolio cost of debt based on current short term observations of corporate bond yields. Under the AER's transition approach, the return on debt allowance would not match the efficient cost of debt until 2024-25 - three regulatory periods.This is clearly inappropriate for a business that already issues debt on a staggered portfolio basis. An immediate application of the trailing average should be preferred because it provides longer term stability.

Clause 6.5.2(k)(1) and (4) of the Rules require that in estimating the allowed return on debt, regard must be had to:

> *the desirability of minimising any difference between the return on debt and the return on debt of a benchmark efficient entity referred to in the allowed rate of return objective;*

The benchmark efficient entity would issue debt on a staggered portfolio basis and would need to be provided with a return on debt consistent with the 10 year trailing average estimate. The trailing average approach to estimating the return on debt would minimise the difference between the allowed return on debt and the benchmark efficient return on debt.Therefore, where possible, and in any case for the NSW DNSPs, the AER should apply an immediate transition to a trailing average approach to setting the cost of debt, which it has recognized reflects the benchmark efficient cost of debt. Using the transition approach would not achieve this outcome.

Interrelationship between the return on equity and the return on debt

Finally, the AER must have regard to "the interrelationship between the return on equity and the return on debt"; when estimating the return on debt such that it contributes to the achievement of the allowed rate of return objective under clause 6.5.2(k)(2) of the Rules.

The cost of equity is, by necessity, based on estimates of the risk adjusted return for businesses facing a similar nature and degree of risk as that faced by Endeavour Energy. None of the privately owned and publicly listed energy network businesses regulated by the AER finance themselves in the manner implied by the AER's transition calculation – with all having an element of a stagger to their debt portfolio. If they did finance debt in the manner implied by the AER's transition then equity in those businesses would be materially higher risk due to the refinancing risk equity investors would have to bear. Consequently, the AER's approach results in an internally inconsistent estimate of the cost of equity and debt – with the former based on real world debt financing strategies and the latter based on a hypothetical strategy, which the AER acknowledges would raise the risk and cost of equity if actually implemented. This emphasises the fact that the benchmark efficient entity that the AER has determined for the purpose of the transition is incorrect, particularly when taking into account the risks of Endeavour Energy.

Conclusion on the cost of debt transition

Endeavour Energy has consistently raised debt on a staggered portfolio basis over the past 10 years, which has allowed us to efficiently manage refinancing risk on our sizeable debt portfolio. Therefore, an immediate transition to a trailing average cost of debt allowance would allow Endeavour Energy to more closely match the efficient costs of servicing debt that we have raised over previous regulatory control periods. Endeavour Energy would not be advantaged nor disadvantaged by an immediate transition to a trailing average cost of debt allowance.The allowance would simply more closely match Endeavour Energy's existing and future efficient debt costs. By contrast, the AER's proposed transitional approach would negatively impact our ability to service our existing efficient costs of debt.

For the reasons outlined above, we consider that applying the AER's proposed transitional approach to setting the cost of debt for Endeavour Energy is inconsistent with the Rules and the NEL. We submit that only the 10 year trailing average approach, with no transition, meets the rate of return objective and other requirements of the National Electricity Rules. It is also the only approach that allows Endeavour Energy to recover at least its efficient costs of debt incurred in providing standard control services.

Endeavour Energy's detailed methodology and calculations for the cost of debt are outlined in the CEG Report titled "WACC estimates, a report for NSW DNSPs", which is attached to this regulatory proposal.

Automatic update of the cost of debt

Clause 6.5.2(i)(2) of the Rules allow the return on debt to be the same for each regulatory year or different across regulatory years within a regulatory control period. The AER's final rate of guideline stated that the AER intends to annually update the cost of debt within a regulatory control period. Endeavour Energy agrees with annually updating the allowed return on debt.

Clause 6.5.2(l) of Rules requires that, where the allowed return on debt is different across regulatory years within a regulatory control period is, that this be effected through an automatic update. Below we outline how the allowed return on debt itself is estimated for each regulatory year over the 2014-19 period.
Endeavour Energy considers that the historical corporate bond yield series recently introduced by the RBA provides a robust source of estimates for the BBB cost of debt for Australian corporate entities. In its report to the NSW DNSPs, CEG advised that the methodology used by the RBA is robust and reliable.[98] In its report, CEG also outlines how the RBA BBB forecast of the cost of debt using a 10 year target tenor can be annualized and converted to an effective tenor of 10 years.[99] This is what is required to obtain an estimate of the 10 year cost of the BBB cost of debt for a benchmark efficient energy network firm for each year within the trailing average sample.

Endeavour Energy considers that the averaging period for each annual observation in the 10 year trailing average should use as many data points as possible to minimize the potential for any single estimate to bias the estimated cost of debt in any particular year. As outlined in a joint NSW DNSP letter to the AER, we outlined that the averaging period for each annual observation of the cost of debt should be 1 January to 31 December.[100] Based on the RBA's current corporate bond yield series this would provide 12 monthly data points of the BBB cost of debt for each year in the 10 year trailing average. By using data up to 31 December each year, the annually updated cost of debt would be available in advance of annual pricing proposals and would also coincide with the cut-off date for annual updates to CPI that are also incorporated as part of annual pricing proposals.

Debt raising costs

The process of raising debt finance incurs significant transaction costs that should be recognised in regulated revenue allowances over the 2014-19 regulatory control period. The AER's standard practice has been to recognise these costs as benchmark efficient operating expenditure and this is reflected in the AER's post-tax revenue model (PTRM). The AER's PTRM requires input of benchmark efficient debt raising costs in basis points per annum (bppa) that is applied to the regulatory asset base.[101]

Incenta has researched market data on debt raising transaction costs and has found that the benchmark efficient debt raising costs for Australian corporate entities incorporate the following:

[98] CEG, WACC estimates, a report for NSW DNSPs, May 2014.
[99] CEG, WACC estimates, a report for NSW DNSPs, May 2014.
[100] NSW DNSPs, Letter to the AER on cost of debt averaging periods, 25 February 2014.
[101] AER, Electricity distribution network service providers: Post-tax revenue model handbook, June 2008, pp. 8-9.

- costs of issuing bonds – this includes arrangement fees, bond master program costs, legal fees, credit rating fees, issuance fees etc).
- costs of establishing and maintaining bank facilities required to meet S&P liquidity requirements and maintain an investment grade credit rating – bank facilities are required in the event that bond markets suddenly lose liquidity and funds are still required for operations as (this was the case during the global financial crisis, European sovereign debt crisis and the US government debt ceiling crisis)
- costs of refinancing debt 3 months ahead of refinancing date, which is required by S&P as a condition of maintaining investment grade credit rating.[102]

Overall Incenta found that the benchmark efficient debt raising costs for Endeavour Energy would be approximately 19.3 bppa on a levelised basis over the 2014-19 regulatory period. The components of these total debt raising costs are outlined below. Of these benchmark efficient debt raising costs, Endeavour Energy propose only to include the debt raising transaction cost component, which is approximately 9.9bppa.

- Total debt raising transaction costs – 21.7 bppa
    - Debt raising transaction costs – 9.9 bppa
    - Liquidity – commitment fee – 5.8 bppa
    - 3 month ahead financing – 6.0 bppa

Cost of equity

Endeavour Energy has assessed all relevant financial models, market data and other evidence[103] to determine that the benchmark efficient cost of equity is in the range 10.11% to 11.5%.

The AER's final rate of return guideline sets out the AER's intended approach to estimating the return on equity using a 'foundation model' approach. The guideline outlines that the foundation model is to be the Sharpe-Lintner Capital Asset Pricing Model (SL CAPM), with:

- evidence from the Black CAPM framework informing the estimate of equity beta in the SL CAPM.
- evidence from the Dividend Growth Model framework informing the estimate of market risk premium in the SL CAPM.
- no evidence to be considered from the Fama-French 3 Factor model.

The guidelines also outline a range of evidence that the AER intends to consider when setting the allowed return on equity. In particular when estimating parameters for input to the SL CAPM, the AER has determined that it will estimate:

- the risk free rate using yields on 10 year Commonwealth government bond securities (10 year CGS) observed over a 20 business day period as close as practically possible to the commencement of the regulatory control period.
- the equity beta based on empirical analysis of Australian energy utility firms the AER considers reasonable comparable to the benchmark efficient (which it states provides an equity beta estimate range of 0.4 to 0.7).

[102] Incenta, Debt raising transaction costs – <<DNSP>>, May 2014.
[103] As required by NER, clause 6.5.2(e)(1).

- other information on equity betas for overseas firms and the theoretical underpinnings of the Black CAPM to inform the final equity beta estimate.
- the market risk premium (MRP) using historical excess returns, dividend growth model estimates, survey evidence and "conditioning" variables.

Following this, other evidence would be considered, including the "Wright approach" to estimating the SL CAPM return on equity, other regulators' return on equity estimates, brokers' return on equity estimates and takeover/valuation reports and comparisons with the return on debt.[104]

We agree that the SL CAPM can be used as a base model for estimating the allowed return on equity. We also agree that the following sources of information should be taken into account when estimating the allowed return on equity:

- evidence from the "Black CAPM" (where we use the term "Black CAPM" to signify the body of theoretical and empirical literature that suggests that equity with a zero measured regression beta will earn a return significantly above the government bond rate. Black (1972)[105] is one important, but far from the only, contribution to this literature)
- evidence from the Dividend Growth Model (DGM estimates of the benchmark return on equity and the return on the market)
- using yields on 10 year CGS as a proxy for the risk free rate (although not restricted to short term observations)
- empirical estimates of the equity beta from both domestic and overseas firms
- estimates of the MRP using historical excess returns

The AER's consideration of relevant evidence is too narrow and does not give proper weight to each source of evidence that should be considered when estimating the cost of equity. The proposed approach in the rate of return guideline disregards empirical estimates of the cost of equity from the Black CAPM, the DGM applied to specific utility firms (as opposed to the market portfolio in aggregate) and completely disregards evidence from the Fama-French 3 Factor Model. For this reason, the approach specified in the rate or return guideline has not had regard to all relevant estimation methods, financial models, market data and other evidence as required by clause 6.5.2(e)(1) of the Rules.

The term 'relevant' used in clause 6.5.2(1)(e) is not defined in the Rules. In the absence of a definition, it is to be given its ordinary meaning in context.[106]

In the context of Rule 6.5.2 which sets out the information that the AER must take into account in determining the allowed rate of return, the ordinary meaning of the term 'relevant' means any estimation methods, financial models, market data or other evidence which could rationally affect the AER's assessment of the allowed rate of return under Chapter 6 of the Rules.

The AER has formulated assessment criteria outlined in the AER's Explanatory Statement on the rate of return guideline published in December 2013 (AER ROR Explanatory Statement) to determine what evidence it will take into account in determining the allowed rate of return.[107] While the AER may use the assessment criteria in forming a view as to whether or not particular evidence is relevant, it is not able to substitute those criteria for the express wording of clause 6.5.2(e)(1) of the Rules. Specifically, Endeavour Energy notes that some of the criteria such as the simplicity or complexity of the information do not go to the question of whether the evidence is able to rationally affect the AER's assessment of the allowed rate of return, and as a consequence cannot determine the relevance of the evidence for the purposes of clause 6.5.2(e)(1) of the Rules.

[104] AER, Final rate of return guideline, December 2013, pp. 11-17
[105] Black, Fischer, Capital market equilibrium with restricted borrowing, Journal of Business 45, 1972, pages 444-454.
[106] Project Blue Sky CLR.
[107] See at pages 23 and 24 of the AER ROR Explanatory Statement.

7 ALLOWED RATE OF RETURN

We also note that the guideline approach for estimating the risk free rate and the MRP is likely to lead to inconsistent parameter estimates within the SL CAPM. The final rate of return guideline identified that there is a requirement for internal consistency in the application of the SL CAPM estimates for the risk free rate and the MRP/expected return on the market.[108] However the final approach outlined in the guideline does not lead to internally consistent estimates of the risk free rate and the MRP being applied and therefore the approach does not take into account interrelationships between estimates of financial parameters (the risk free rate and the MRP in the SL CAPM) that are relevant to the estimate of the return on equity, which is required by clause 6.5.2(e)(3) of the Rules.

We propose to depart from the AER's approach as to the estimation methods, financial models, market data and other evidence to be taken into account when setting the allowed return on equity in a number of areas, as we believe it is inconsistent with the requirements of the Rules:

- estimation of the risk free rate
- using the Black CAPM cost of equity estimate to inform the choice of point for the allowed return on equity
- using empirical estimates of the benchmark efficient cost of equity using the Black CAPM to inform estimates of the equity beta when the applying the SL CAPM to set the allowed return on equity
- using the FFM cost of equity estimate to determine whether estimates from the base model are reasonable
- using the DGM estimate of the required return on equity to inform the allowed return on equity.

In the following sections we set out our proposed return on equity and in accordance with schedule 6.1.3 of the NER, we explain our reasons for departing from particular aspects of the AER's method for setting the allowed return on equity. In contrast, the AER's proposed approach is unlikely to achieve the rate of return objective and may not allow Endeavour Energy to recover at least its efficient costs of equity finance.

Proposed approach

Endeavour Energy has assessed all relevant financial models, market data and other evidence as required by clause 6.5.2(e)(1) of the Rules to determine that the benchmark efficient cost of equity is in the range 10.11% to 11.50%. This range incorporates cost of equity estimates using long term and short term financial market data. It also incorporates estimates of the required return on equity/equity related parameters using different financial models including the SL CAPM, the Black CAPM, the Fama French 3 Factor Model (FFM) and the Dividend Growth Model (DGM). We set out below why these estimates are relevant evidence that the AER must consider in determining the allowed rate of return pursuant to clause 6.5.2(e)(1), and the weight that they AER should attribute to them in determining the cost of equity.

Table 37: Proposed cost of equity using CAPM point estimate

Cost of equity model	Parameter approach	Estimated cost of equity
Models that do not account for "low beta bias"		
SL CAPM	Long term – MRP and rfr estimated over a consistent time period	10.1%
SL CAPM	Long term (Wright approach) – Rm estimated over a historical time period.	10.2%
SL CAPM	Short term – MRP and rfr estimated over a consistent time period	10.1%

108 AER, Explanatory Statement to final rate of return guideline, December 2013, Appendices, p. 108

Models that do account for "low beta bias"		
Black CAPM	E(rm) and zero beta premium estimated over a long term period	10.7%
FFM	Contemporaneous rfr, Equity Beta, MRP, SMB and HML factors	10.91 – 11.5%
CAPM (informed by DGM)	0.94 beta (based on DGM estimates of relative risk), DGM for E(Rm) and prevailing CGS for risk free rate	11.0%
Overall Range		**10.1 – 11.5%**

Source: CEG, WACC estimates, a report for NSW DNSPs, May 2014. Table 8 and section 2.8. * "low beta bias" is the bias associated with using government bonds as the proxy risk free rate proxy and using regression estimates of betas. **Average of CEG and SFG based estimates. All estimates are based on a gamma of 0.25 and would be higher with the AER's proposed gamma of 0.5.

Within the range of estimates, Endeavour Energy proposes a 10.11% cost of equity, which is commensurate with the minimum efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to Endeavour Energy.[109] Specifically, our approach to estimating the required cost of equity, combined with our proposed approach to estimating the cost of debt is consistent with providing returns on equity that ensure long term stability and predictability of returns to equity holders. This is the profile of returns that is commensurate with the returns required by investors in benchmark efficient entities with a similar degree of risk as that which applies to Endeavour Energy in the provision of standard control services.

This cost of equity is based on long term data and internally consistent parameter estimates within the SL CAPM framework. In arriving at parameter estimates for input to the SL CAPM, we have had regard to all relevant estimation methods, financial model, market data and other evidence as required by clause 6.5.2(e)(1) of the NER.

The parameter estimates we have used to estimate the 10.11% minimum required return on equity within the SL CAPM framework are outlined below:

- Rf – a nominal risk free rate of 4.78% based on historic yields on 10 year Commonwealth Government bonds using data from 1883 to 2011, consistent with the dataset underpinning the calculation of the market risk premium
- MRP – a market risk premium of 6.5%, based on long term historic data (1883 to 2011)[110] and consistent with the recommended position contained in the AER Rate of Return Guideline; and
- βe – an equity beta of 0.82, consistent with the best empirical estimate from Strategic Financial Group Consulting (SFG), which incorporates data from Australian listed energy network firms and US comparator firms,[111] drawing on evidence from CEG.[112] This estimate is informed by the empirical approaches suggested by a number of Australian academics.[113]

Our proposed SL CAPM point estimate for the allowed return on equity is summarised in the table below.

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[109] As required by NER, clause 6.5.2(c).

[110] NERA "The market, size and value premiums", June 2013, p. 17.

[111] SFG, Equity beta, May 2014, p. 41 and SFG, Regression based estimates of risk parameters for the benchmark firm, p. 16.
[112] CEG, Information on equity beta from US companies, June 2013 and CEG, AER equity beta issues paper: International comparators, October 2013.
[113] Gray et. al., Comparison of OLS and LAD regression techniques for estimating beta, June 2013; Gray et. al., The Vasicek adjustment to beta estimates in the Capital Asset Pricing Model, June 2013; Grey et. al., Assessing the reliability of regression-based estimates of risk, June 2013.

7 ALLOWED RATE OF RETURN

Table 38: Proposed cost of equity using CAPM point estimate

Parameter	Basis of estimate	Estimate
Risk free rate, rfr	Long term data 1883-2012	4.78%
Equity beta, β	Data from the small sample of Australian listed energy network firms and large sample of US comparator forms	0.82
Market risk premium, MRP	Long term data 1883-2012	6.50%
Overall cost of equity estimate		**10.11%**

A detailed description of the approach and calculations of Endeavour Energy's proposed return on equity is provided in the CEG Report titled "WACC Estimates, a report for NSW DNSPs", which is provided as an attachment to this regulatory proposal.

In terms of equity beta, the AER's small sample of publicly listed Australian energy network firms (currently only 5 firms out of the sample remain listed) produces equity beta estimates between 0.4 – 0.7.[114] Recently, the AER has released an updated empirical report which widens the AER's range for point estimates of equity beta even further to between 0.3 and 0.8. This wide range is indicative of the difficulty in developing a robust estimate of the equity beta for application in the SL CAPM.[115] However, expanding the AER's sample to include equity beta estimates for US listed energy network firms broadens the sample to include data on over 56 US firms. Even when giving each Australian observation twice the weight of each US observation the resulting weighted average beta is 0.82. This improves the statistical robustness of the equity beta estimate[116] and produces a result that is closer to estimates of the required return on equity from other models such as the DGM and the FFM.

Basis of proposed cost of equity

The AER's final rate of return guideline proposes to estimate the risk free rate using only short term observations of the 10 year CGS[117] but to give greatest consideration to historical averages in estimating the market risk premium.[118] This is an inconsistent approach to populating the SL CAPM to estimate a required return on equity. This is demonstrated by the SL CAPM equation itself. The SL CAPM is specified as outlined at step 1:

1. expected return on equity for a stock = Risk free rate + β (Expected return on the market – Risk free rate)
2. the AER estimates (Expected return on the market – Risk free rate=Market Risk Premium) having most regard to the historical average market returns in excess of historical average risk free rates
3. the AER then implements equation in (1) by combining the Market Risk Premium estimated in step (2) with a prevailing risk free rate. This gives rise to an estimate of expected return on equity for a stock = Prevailing risk free rate + β (Historical return on the market in excess of Historical risk free rate)

However, fundamentally, the market risk premium is defined in the CAPM as the expected return to the market portfolio less the risk free rate.119 As a result, whatever risk free rate is used to estimate the MRP must be the

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[114] AER, Explanatory statement to the final rate of return guidelines, December 2013, p. 86
[115] Henry O., Estimating beta: an update, April 2014, p. 63.
[116] See CEG, Information on equity beta from US companies, June 2013, SFG, Report on equity beta, May 2014, p. 15, and SFG, Regression based estimates of risk parameters for the benchmark firm, June 2013.
[117] AER, Final rate of return guideline, December 2013, p. 15.
[118] AER, Explanatory statement to final rate of return guideline, December 2013, p. 95.
[119] CEG, Estimating the return on the Market, June 2013, p. 4.

same as the risk free rate separately input as the first term on the right hand side of equation (3) above. The AER's approach will result in a short term estimate of the risk free rate being used as the first term on the right hand side of equation (3) above, but a different (long term) estimate of the risk free rate being embedded within the MRP estimate. This can result in an internally inconsistent application of parameters within the allowed return on equity.

This internal inconsistency means that this approach cannot be relied on to promote the allowed rate of return objective. Moreover, clause 6.5.2(e)(3) of the NER, requires that the allowed rate of return estimate must have regard to any interrelationships between estimates of financial parameters that are relevant to estimates of the return on equity and the return on debt. This explicitly directs the AER to have regard to interrelationships within the parameters used to estimate the cost of equity.

The requirement in clause 6.5.2(e)(3) was specifically included in the Rules to recognise that for a financial model to be reliable it must properly reflect any interactions between the parameters within the model. In models where two or more parameters are mathematically linked or there is an empirical relationship between them, proper implementation of the model requires that any mathematical relationship between parameters be recognised when estimating those parameters. We note that the AEMC was concerned to ensure that the rate of return framework speficially stated that such interrelationships of parameter values be recognised.[120]

The internal inconsistency is demonstrated even more clearly when the basis of the AER's historical MRP estimates is considered. In the final rate of return guideline, the AER states that it will give primary weight to historical estimates of the MRP and notes estimates in the range 5.7 – 6.4%. We note that NERA economic consulting has produced the most recent and comprehensive estimate of historical excess returns of 6.5% for the period 1883 to 2011.[121] The method used to estimate these excess returns in the historical studies is as follows:

- estimate total annual returns on equity for Australian firms (including both dividends and capital gains)
- then remove the yield on 10 year CGS for each year.

The estimate therefore starts with the actual return on the Australian market and subtracts the proxy for the risk free rate to provide a market risk premium estimate. The only way to avoid inconsistency between the risk free rate estimate used by the AER and the historically estimated market risk premium are to either:

- estimate the risk free rate as the average yield on 10 year CGS over the period 1883-2011 as we propose or
- estimate the risk free rate using short term observations of yields on 10 year CGS and estimate the market risk premium based on short term estimates, such as DGM based forecasts of the expected return on the market over the same period as the risk free rate proxy is observed, minus this same risk free rate.

We propose option 1 because a long term approach using the SL CAPM is likely to deliver the most stable cost of equity allowances over time. This approach is consistent with the trailing average approach that we adopt for estimating the cost of debt and is likely to ensure more stable price outcomes for electricity customers between regulatory periods and provides for stable, predictable outcomes for investors over the long term. The estimated cost of equity using option 1 is currently 10.11%. We also note that, as shown above, option 2 gives very similar estimates – also centered on 10.1% (CEG has estimated 10.1% and SFG based estimates are 10.2%).

SFG has estimated that the prevailing expected return on the market is around 10.32% excluding any value for imputation credits.[122] SFG has estimated a risk free rate of 4.12% over the 20 days ending on 14 February 2014. This implies a market risk premium excluding the value of imputation credits of 6.2%. Applying an equity

[120] AEMC, Draft Rule Determinations Draft National Electricity Amendment (Economic Regulation of Network Providers) 2012, 23 August 2013, p. 50.
[121] See NERA "The market, size and value premiums" provided as Attachment 7.09.
[122] SFG, Alternative versions of the dividend discount model and the implied cost of equity, May 2014, p. 59.

beta of 0.82 gives DGM estimate of the required return on equity before imputation credits of 9.2% (=4.1%+0.82*(10.3%-4.1%)). However, the cost of equity that is entered into the PTRM is inclusive of imputation credits and SFG advises that, for a gamma of 0.25, the pre-imputation credit must be divided by 0.9032 which gives a cost of equity inclusive of the value of imputation credits of 10.20%.

CEG has similarly estimated that the prevailing expected return on the market is around 11.4% including the value for imputation credits. CEG has estimated a risk free rate of 4.0% over the 20 days ending on 13 May 2014. This implies a market risk premium including the value of imputation credits of 7.41%. Applying an equity beta of 0.82 gives DGM estimate of the required return on equity inclusive of the value of imputation credits of 10.0% (=4.0%+0.82*(11.4%-4.0%)).

Consistency of parameters within the cost of equity

The Wright approach

The AER's final rate of return guideline states that, towards the end of its estimation process for the cost of equity, the AER would take into account evidence from the "Wright" approach. The "Wright" approach simply involves estimating the required return on the market based on the historical average market return on equity (rather than estimating the MRPbased on historical excess returns on equity). As outlined above, the SL CAPM requires an estimate of the expected return on the market and then combines this with estimates of the risk free rate and the equity beta.

The historical estimates of the MRP used by the AER are estimated using annual returns on the equity market (dividends and capital gains) less the risk free rate proxy (10 year CGS yield) in the same year. Applying the "Wright" approach to this same historical data would involve estimating the expected return on the market using the annual returns on the equity market and then combining this with an appropriate estimate of the risk free rate and equity beta. CEG has constructed estimates in this manner and have found that the approach produces much more stable cost of equity forecasts over time.

CEG has estimated that the historical average return on the market in Australia (normalised to a 2.5% inflation environment) is 11.56%. Over the 20 trading days ending on 13 May 2014, average yield on 10 year CGS is 4.0% - implying an MRP of around 7.4%. With an equity beta of 0.82 the Wright approach delivers an estimate of the cost of equity of 10.2% (10.2%=4.0%+0.82*(11.6%-4.0%)). Notably, this value is almost identical to the cost of equity derived when the MRP is estimated using the DGM model.

By contrast, combining a 4.0% prevailing risk free rate with a historical average MRP estimate of 6.5% and an equity beta of 0.82% will results on a cost of equity estimate of 9.3% - substantially lower than the Endeavour Energy's proposal which is itself lower the estimates from applying the Wright approach and the DGM approach (all with the same equity beta).

We note that the "Wright" approach is not a separate model, but is in fact a way to parameterise the SL CAPM that should be used when distilling a cost of equity estimate from that model. (which aligns closely to the approach suggested by Professor Wright himself, which is that the primary focus should be on the real cost of equity).[123] CEG has advised that the "Wright" approach should also be used to check whether a combining an estimate of MRP based on one risk free rate measure with a different measure of the risk free rate produces a reasonable outcome. It is clear from CEG's work that applying the AER's approach that combines a short-term risk free rate and a long term estimate of the MRP does not produce a reasonable outcome when compared to the Wright approach using the same underlying data.[124]

This highlights the significant internal inconsistency in the AER's approach to parameterising the SL CAPM, which is discussed above

[123] Conclusion vii in Wright S., Response to Professor Lally's Analysis, November 2012, p. 3.
[124] CEG, WACC estimates, A report for NSW DNSPs, May 2014.

7 ALLOWED RATE OF RETURN

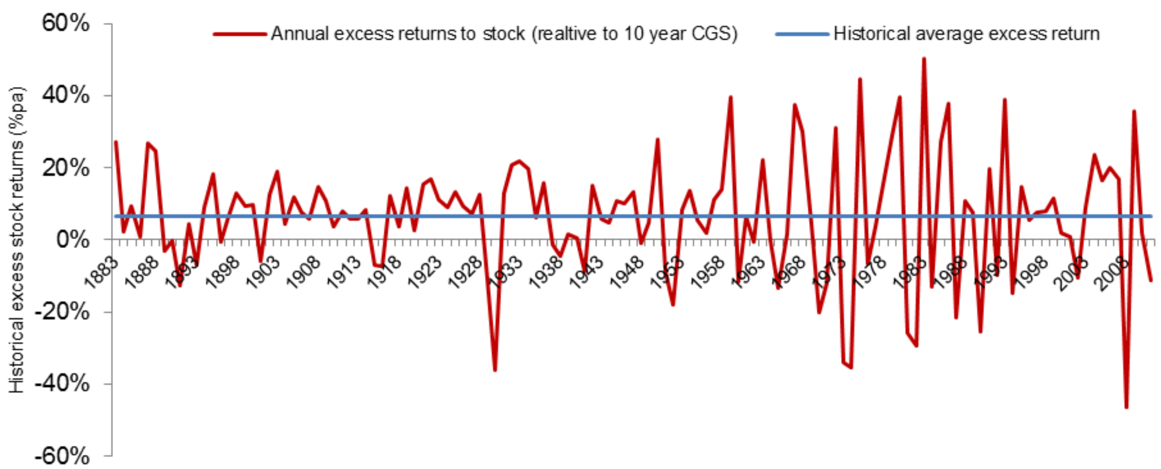
Prevailing market conditions

Clause 6.5.2(g) of the NER requires that in estimating the allowed return on equity, regard must be had to prevailing conditions in the market for equity funds. We have had regard to prevailing market conditions by considering short term estimates of the return on equity using the DGM to derive internally consistent SL CAPM parameters above, this provides a cost of equity estimate of 10.1% (averaging CEG and SFG based estimates), which is very similar to our proposed 10.11% cost of equity using long term estimates. Having regard to these estimates would suggest a cost of equity higher than our proposed estimate. However, having regard to longer term stability we are proposing an allowed return on equity of 10.11%. We believe this will maintain the minimum return on equity required to attract investment into the business over the long term.

We note that estimating the allowed return on equity using historical data is not in itself inconsistent with prevailing market conditions. Historical data is likely to inform investors' expectations and requirements of equity returns over 2014-19.

There is also an advantage to using historical data – it can help to smooth out short-term volatility in financial market data. For example, when estimating historical excess returns, the data relied on by both the AER and Endeavour Energy, yearly data shows significant variation over the estimation period. This is illustrated in the figure below. However, averaging this data (as per the blue line in the figure below) using a long term approach would promote stability in allowed equity returns across energy network determinations.

Figure 23: Historical realized excess returns on the market



Source: CEG WACC Estimates, a report for the NSW DNSPs, May 2014.

We also note that the AEMC's final rule determination on the current NER specifically noted that the requirement to determine a rate of return that is commensurate with prevailing conditions is not meant to exclude from consideration historical or realised returns. As outlined, we have had regard to prevailing market conditions and find that our proposed cost of equity is not inconsistent with prevailing market conditions as highlighted by internally consistent short term estimates of the SL CAPM return on equity.

Range of estimate for the cost of equity

There is uncertainty when estimating the benchmark efficient cost of equity because the available information on required returns for equity investments in energy networks is imperfect (indeed the available information on the required returns on equity generally is imperfect). We have been guided by the requirements of the NER when assessing the available information. In particular, the allowed return on equity must be estimated such that it is consistent with allowed rate of return objective (clause 6.5.2(f) of the NER). The allowed rate of return objective is that:

7 ALLOWED RATE OF RETURN

…the rate of return … is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the [service provider] in respect of the provision of [regulated services].[125]

To achieve this objective we have considered all relevant estimation methods, financial models, market data and other evidence as required by clause 6.5.2(e)(1) of the NER.

The Black CAPM

The rate of return guideline approach disregards empirical estimates of the cost of equity from the Black CAPM. However, Endeavour Energy considers that empirical estimates of the cost of equity from the Black CAPM are relevant evidence that the AER must take into account in determining the allowed are of return pursuant to clause 6.5.2(e) of the Rules. Recent analysis from CEG and Strategic Finance Group Consulting (SFG) illustrates that the Black CAPM framework can be used to provide robust cost of equity estimates for the benchmark energy network firm.[126]

Moreover, use of the Black CAPM is likely to lead to more accurate forecasts of required equity returns over the forecast period. This is because the Black CAPM framework relaxes a key assumption of the SL CAPM that all investors can borrow and lend as much as they like at the risk free rate. As noted by the AER, the Black CAPM acknowledges that investors may not be able to borrow and lend at the risk free rate (the AER states that it is in fact unlikely that investors have unlimited ability to borrow and lend at the risk free rate).[127] By relaxing the SL CAPM assumption that investors have unlimited ability to borrow and lend at the risk free rate the Black CAPM framework can more effectively explain movements in equity returns and therefore predict what equity returns would be required over 2014-19.

Using this information would enable the AER to take into account market data on the required return on equity for a benchmark efficient energy network firm with a similar degree of risk as that which applies to Endeavour Energy in respect of the provision of standard control services. This would contribute to the achievement of the allowed rate of return objective and is therefore relevant evidence that should be considered (in accordance with clause 6.5.2(e) of the Rules) when estimating the allowed return on equity for Endeavour Energy over the 2014-19 regulatory control period.

We have used the Black CAPM cost of equity estimate to inform the range of reasonable cost of equity estimates as outlined above. Although, we have not used the Black CAPM as base model, our proposed approach uses empirical estimates of the benchmark efficient return on equity from the Black CAPM to both:

- Inform the choice of a point estimate for the allowed return on equity, and
- Inform estimates of the equity beta when applying the SL CAPM to set the allowed return on equity.[128]

With regard to the second point, the zero beta premium estimates from SFG129(and many other academic studies as listed by CEG), suggest that only considering regression based estimates of equity beta to predict the required return on equity within the CAPM is likely to produce a downwardly biased estimate for low beta stocks. This is a relevant consideration when determining the equity beta estimate that is used to populate the SL CAPM under the AER's "foundation model" approach.

Even though SFG/CEG's best regression based estimate of equity beta (0.82) is above the top of the AER's range (0.70), the evidence from CEG, Grundy, NERA and SFG using the Black CAPM framework suggests

[125] Rule 6.5.2(c).

[126] SFG, Cost of equity in the Black capital asset pricing model, May 2014.

[127] AER, Explanatory statement to the rate of return guideline, Appendices, p. 17.

[128] The AER proposed to use only the theoretical underpinnings of the Black CAPM to inform its equity beta estimate. See AER, Explanatory statement to the final rate of return guideline, Appendices, pp. 16-18. However the recent evidence from SFG strongly suggests that empirical evidence from the Black CAPM should be taken into account both when estimating the return on equity as well as determining what estimate of equity beta should be used when setting the allowed return on equity.
[129] SFG, Cost of equity in the Black capital asset pricing model, May 2014.

that using the AER's implementation of the SL CAPM (using the government bond rate as the risk free rate proxy) is likely to underestimate the required return on equity for stocks with an empirical equity beta less than 1.0.[130] This means that, even with a 0.82 equity beta, required returns are likely to be underestimated using the AER's implementation of the SL CAPM.

Therefore we propose that, as a minimum, the Black CAPM evidence suggests that the more robust empirical equity beta estimate of 0.82 should be used. We note that, based on the advice of Grundy, CEG and SFG, fully adjusting for the above underestimation would require an increase in the estimated cost of equity by around (1-0.82)*0.5*MRP. This would be an increase of 59 basis points for an MRP of 6.5%.

The Fama-French three factor model

The AER's final rate of return guideline gives no weight to the Fama-French three Factor Model (FFM). We consider that the FFM is a relevant financial model that the AER should have regard to pursuant to clause 6.5.2(e)(1) of the Rules.

Estimating the required return on equity for a benchmark efficient firm over the 2014-19 period effectively requires a prediction of what equity investors require/expect over that period. The FFM significantly improves predictability of stock returns over time compared to the SL CAPM (which, as discussed below has been recognised by the Nobel Prize Committee). Considering estimates of the return on equity for the benchmark efficient firm using the FFM model would help to develop an estimate of the return on equity that is commensurate with prevailing conditions in the market for funds over the 2014-19 period as required by clause 6.5.2(g) of the Rules.

Considering estimates of the return on equity from the FFM would also assist in developing an estimated return on equity that is commensurate with the required return on equity for a benchmark efficient firm with a similar degree of risk as that which applies to Endeavour Energy in respect of the provision of standard control services, as required by clauses 6.5.2(f) and 6.5.2(c) of the Rules.

One of the authors of the FFM, Eugene Fama, has recently won the Nobel prize in part for his work on the FFM model. The Nobel Prize Committee noted that the FFM model significantly improves predictability of stock returns over time compared to the SL CAPM. The Committee's background paper notes that:

> *…the classical Capital Asset Pricing Model (CAPM) – for which the 1990 prize was given to William Sharpe – for a long time provided a basic framework. It asserts that assets that correlate more strongly with the market as a whole carry more risk and thus require a higher return in compensation. In a large number of studies, researchers have attempted to test this proposition. Here, Fama provided seminal methodological insights and carried out a number of tests. It has been found that an extended model with three factors – adding a stock's market value and its ratio of book value to market value – greatly improves the explanatory power relative to the single-factor CAPM model.*[131]

The Committee also noted:

> *…following the work of Fama and French, it has become standard to evaluate performance relative to "size" and "value" benchmarks, rather than simply controlling for overall market returns.*[132]

These statements provide a clear indication that the Nobel Prize Committee considers the FFM model is a relevant financial model for estimating equity returns.

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[130] SFG, Cost of equity in the Black capital asset pricing model, May 2014 and NERA, Estimates of the zero beta premium, June 2013.
[131] Economic Sciences Prize Committee of the Royal Swedish Academy of Sciences, UNDERSTANDING ASSET PRICES, Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, October 2013, p3.
[132] Economic Sciences Prize Committee of the Royal Swedish Academy of Sciences, UNDERSTANDING ASSET PRICES, Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, October 2013, p44.

However, the AER's final rate of return guideline concluded that the FFM was not a relevant financial model to have regard to when setting the allowed return on equity. The AER concluded that:

- the FFM model risk factors have no clear theoretical foundation
- the empirical patterns on which the FFM was developed may be variable over time, and may not apply in Australia
- the FFM is complex to implement
- to the AER's knowledge, the model is not used to estimate future returns on equity in Australia.

NERA have responded to many of these concerns in a report that was previously submitted to the AER. NERA set out, contrary to the AER's statements in the final rate of return guideline that:[133]

- the FFM has strong theoretical foundations
- there are benefits to using the FFM to estimate the cost of equity for value stocks (which SFG has demonstrated that the benchmark energy network firm is likely to be[134])
- the FFM is used in practice[135]

Furthermore, in response to the AER's claims that the FFM is complex to implement, estimates of the required return on equity using the FFM are readily available to the AER.[136] CEG has estimated the return on equity for the benchmark efficient energy network firm to be approximately 11.5% using long term estimates of parameters in the FFM and 10.7% using short term estimates of parameters. This analysis is based, in part on SFG's analysis referred to above.

Only using return on equity estimates produced by the SL CAPM (which is the approach outlined in the AER's final rate of return guideline) disregards relevant evidence from FFM estimates of the required return on equity, which is inconsistent with clause 6.5.2(e)(1) of the Rules. Due to the FFM's greater ability to fit data on stock returns than the SL CAPM, empirical estimates of the benchmark efficient required return on equity using the FFM:

- provide relevant information on prevailing conditions in the market for funds (as required by clause 6.5.2(g) of Rules) in addition to information from the empirical estimates using only the SL CAPM
- provide information on the required return on equity for a firm facing a similar nature and degree of risk as that faced by EndeavourEnergy in addition to evidence from the empirical estimates using only the SL CAPM.

We propose that the benchmark cost of equity estimates produced by CEG using the FFM framework should be considered when setting the allowed return on equity for Endeavour Energy to determine whether estimates from the base model we have used are reasonable. The FFM estimates indicate that our proposed return on equity of 10.11% is reasonable and if anything is at the low end of the reasonable estimates. Considering empirical estimates of the benchmark efficient return on equity using the FFM and assessing the allowed return on equity in this manner will result in a more accurate estimate of the return on equity for a benchmark efficient firm facing a similar nature and degree of risk as that faced by Endeavour Energy in providing standard control services than an approach which disregards all evidence from the FFM. Therefore considering evidence from the FFM as we propose will achieve the allowed rate of return objective and will contribute to achieving the National Electricity Objective, whereas disregarding all evidence from the FFM as proposed in the AER's final rate of return guideline will not.

[133] NERA, The Fama-French Three Factor Model, October 2013.
[134] SFG, Regression based estimates of risk parameters for the benchmark firm, June 2013.
[135] See The Fama-French Three Factor Model, October 2013, pp. 34-42.
[136] AER, Explanatory Statement to the Final rate of return guideline, December 2013, Appendices, p 23.

The Dividend Growth model

The AER's final rate of return guideline recognises that the Dividend Growth Model (DGM) is a relevant financial model that should be considered when setting the allowed return on equity.[137] The guideline states that the underlying financial theory of the model (that the price of an asset should be equal to the present value of the expected future cash flows from that asset) is well accepted and sound.[138] The guideline also states that the dividend and price information needed to estimate the required return on equity using the DGM are readily observable in the market and as such the model is flexible to reflect changing market conditions.

However, the guideline states that the DGM suffers from implementation issues because the estimates are sensitive to dividend yield and growth rate assumptions. The guideline refers to estimates of the benchmark network business rate of return using the single period (constant growth rate) DGM to demonstrate this sensitivity. The guideline states that the DGM applied to overall equity market returns does not suffer the same implementation issues as the estimates for the benchmark firm. Based on these considerations, the guideline concludes that the DGM should only be used to inform the estimate of the MRP.

We agree with the AER, that the DGM should be used to inform the estimate of the MRP/Expected return on the market when applying the SL CAPM (SFG has estimated that the three stage DGM implies an MRP of 6.43% using data from July 2002 to January 2014 and 7.46% using market data from January 2010 to November 2013[139]). However, we also consider that the DGM can be used to provide an estimate of the required return on equity for a benchmark regulated firm. DGM based estimates of the required return on equity are very useful, because the nature of estimates are quite different to the SL CAPM, Black CAPM and FFM based estimates of the return on equity.

The DGM relies on dividends, earnings, share prices and forecasts of dividend/earnings growth, whereas the SL CAPM, Black CAPM and FFM based models rely on regression based estimates of risk parameters. The DGM therefore provides a largely independent estimate of the benchmark return on equity for a regulated energy network firm, which should be taken into account when assessing the range of cost of equity estimates.In concluding that the DGM should not be used to estimate the required return on equity for the benchmark efficient firm, the AER has referred to implausible estimates of the return on equity for the benchmark efficient energy network firm produced by the single-stage (constant growth rate) DGM.[140] However, the AER's guideline has not substantively addressed the DGM estimates of the return on equity that have been developed by SFG which do not impose long run dividend growth rate [141] other than to say SFG's DGM is complex.[142]

The DGM outlined by SFG reduces sensitivity of return on equity estimates to the perpetual growth rate assumption for dividends. This is because the model allows the dividend growth rate to transition from current levels to a reasonable long term assumption for growth in dividends.[143] SFG has recently updated its analysis of the DGM based estimates of the return on equity for firms with a similar degree of risk as that which applies to benchmark efficient regulated energy networks.[144] In its latest report on the DGM, SFG outlines the theory and application of the DGM in estimating the required return on equity and demonstrates that estimates of the required return on equity for the benchmark efficient firm can and should be used when setting the allowed return on equity in energy network determinations under the Rules.

SFG's report outlines that the required return on equity for the benchmark efficient energy network firm is approximately 11.0% using a DGM based estimate of relative risk for the equity beta (as opposed to a regression based estimate of beta) in the CAPM.[145] We consider this is relevant evidence within the meaning of clause 6.5.2(e)(1) of the Rules because the DGM has a sound empirical basis (as acknowledged by the AER)

[137] AER, Final rate of return guideline, December 2013, p.13 and AER, Explanatory statement to the final rate of return guideline, December 2013, p. 96.
[138] AER, Explanatory statement to the final rate of return guideline, Appendices, December 2014, pp. 14-15.
[139] SFG, Alternative versions of the Dividend Growth Model, May 2014, p. 11.
[140] AER, Final rate of return guideline, Appendices, December 2014, pp. 14-15.
[141] SFG, Dividend discount model estimates of the cost of equity, June 2013.
[142] AER, Final rate of return guideline, , December 2014, pp. 14-15.
[143] SFG, Dividend discount model estimates of the cost of equity, June 2013, pp. 11–16.
[144] SFG, Alternative versions of the Dividend Growth Model, May 2014, p. 64.
[145] SFG, Alternative versions of the Dividend Growth Model, May 2014, p. 64.

and because SFG's DGM incorporates mean reversion of growth in dividends. By enabling mean reversion of growth in dividends, SFG's DGM approach addresses the implementation problems referred to by the AER (which exist for the constant growth versions of the DGM). In addition, SFG's DGM based estimate relative risk for the benchmark efficient energy network firm reflects prevailing market conditions as required by clause 6.5.2(g). This is because it uses current equity prices and dividend yields.

By reflecting prevailing conditions in the market for funds and not requiring regression based estimates of risk parameters, DGM based estimates of the required return on equity for the benchmark firm (i.e. using the DGM based relative risk estimate of the equity beta as SFG does) are likely to improve estimates of the required return on equity for a benchmark efficient firm facing a similar nature and degree of risk as that faced by Endeavour Energy.

We consider that SFG's DGM based estimate of the required return on equity for the benchmark efficient energy network firm (11.0%) indicates that our proposed return on equity of 10.11% is at the low end of reasonable estimates taking into account all relevant financial models, and other evidence as required by clause 6.5.2(e)(1) of the Rules. Considering estimates of the benchmark efficient return on equity as informed by a DGM based estimate of relative risk to estimate the equity beta in the CAPM will result in a more accurate estimate of the return on equity for a benchmark efficient firm facing a similar nature and degree of risk as that faced by Endeavour Energy in providing standard control services than an approach which does not consider estimates of the benchmark efficient cost of equity using the DGM framework. Therefore considering evidence from the DGM as we propose will achieve the allowed rate of return objective and will contribute to achieving the National Electricity Objective, whereas the proposed approach in the AER's final rate of return guideline will not.

Equity raising costs

Raising equity finance incurs costs that should be recognised in regulated revenue allowances over the 2014-19 regulatory control period. The AER's standard practice has been to recognize equity raising costs as capex within the PTRM and amortise these costs over the life of the assets that they are used to fund.[146] Endeavour Energy has applied the AER's standard cash flow analysis sheet within the PTRM to estimate the benchmark efficient equity raising costs that are estimated over the 2014-19 regulatory control period. The components are[147]:

- seasoned equity offering (SEO)/Subsequent equity raising costs – 3% over the 2014-19 period
- dividend re-investment plan cost – 1% over the 2014-19 period

In estimating the benchmark efficient equity raising costs we have assumed a dividend re-investment plan take-up of 30% and a dividend payout ratio of 70% (this is consistent with our assumption of the imputation credit payout ratio, which is discussed further below.

[146] See for example AER, Final decision, ElectraNet 2013-14 to 2017-18 transmission determination 2013-14 to 2017-18, p. 87; AER, Final Distribution Determination Aurora Energy Pty Ltd, 2012-13 to 2016-17, April 2012, p. 78; AER, Final decision, Powerlink transmission determination 2012-13 to 2016-17, April 2012, pp. 107-108; AER, Final decision, Victorian distribution determinations 2011-2015, Appendix O, pp. 505–506; AER, Final decision, Qld Distribution determination 2010-11 to 2014-15, May 2010, p. 201;

[147] AER, Powerlink transmission determination 2012-13 to 2016-17 April 2012, p. 108

Imputation credits

The NER state that the estimated cost of corporate income tax should be reduced by the value of imputation credits.

Within the post-tax revenue model framework, the allowed revenues for tax expense will be less than the company is actually likely to incur. Most companies pay a cost of corporate income tax equal to 30% of Earnings after operating expenditure, interest costs and depreciation. However, under the NER framework, the revenues allowed for cost of corporate tax is reduced by the assumed value of imputation credits as set out in clauses 6.5.3 of the NER:

Estimated cost of tax = (Estimated taxable income × Corporate tax rate) (1- value of imputation credits)

This effectively reduces the post-tax return on equity provided by the company and assumes that a portion of the post-tax return on equity is achieved through the value of imputation credits. Therefore, it is absolutely essential that the estimated value of imputation credits represents the value of imputation credits to investors within the company. If the imputation credit assumption is higher than the value that investors attribute to them, then ceteris paribus, regulated revenues will not be sufficient to provide the allowed return on equity applied in the determination. This outcome would not be consistent with the section 7A of the NEL, which requires that:

> *(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—*
>
> *(a) providing direct control network services; and*
>
> *(b) complying with a regulatory obligation or requirement or making a regulatory payment*

The AER's final rate of return guideline applies an approach that defines the value of imputation credits (gamma) as the product of:

- the payout ratio for imputation credits; and
- the utilisation rate (theta or Θ), which is the value of each dollar of distributed imputation credits

The AER applies an estimate of the payout ratio of 70%. The AER estimates the utilisation rate as 0.7 based on excessive weighting to the "equity ownership" approach and tax statistics estimates. However, this approach does not actually estimate the value of distributed imputation credits to investors.

Endeavour Energy proposes to calculate gamma in accordance with the Monkhouse formula, as the product of:

- the distribution rate (i.e. 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 (referred to as theta).

Endeavour Energy proposes a distribution rate of 0.7, which is consistent with the AER's rate of return guideline. Recent empirical evidence continues to support a distribution rate of 0.7.[148]

[148] NERA, The payout ratio, June 2013.

7 ALLOWED RATE OF RETURN

Endeavour Energy proposes a value for theta of 0.35. The reasons why Endeavour Energy is proposing a different value for theta to that in the rate of return guideline include:

- Endeavour Energy does not agree with the conceptual framework adopted by the AER for estimating theta, and in particular the focus on utilisation evidence, rather than market value evidence. The AER's approach is not consistent with the NEO. It does not measure the required return for the purposes of promoting efficient investment, and would lead to underinvestment;
- In order to provide an acceptable overall return to equity holders, theta must be estimated as the value of distributed imputation credits to equity-holders. This is the conventional and orthodox approach to estimating theta. It is also the approach which best gives effect to the NEO, as it provides for recognition of the value to equity-holders of imputation credits and provides for overall returns which promote efficient investment.
- There are compelling reasons why the benefit of imputation credits, which is the amount by which the allowable return otherwise calculated in accordance with the NER should be reduced, is significantly less than the face value of imputation credits or the utilisation of imputation credits. However, these were not considered in the rate of return guideline.
- The value for theta proposed by Endeavour Energy accords with what one would expect to be the additional benefit conferred by the system of imputation credits. The value of theta proposed in the rate of return guideline does not;
- There are overwhelming problems with the taxation statistics and other forms of evidence given primary emphasis in the rate of return guideline. They are, and are well recognised to be, simply unreliable. Further, a key piece of evidence used by the AER (Handley and Maheswaran (2008)) is not an empirical study at all (because the data was not available), but merely involves an assumption of full utilisation by domestic investors; any reliance upon it involves obvious error.
- The only source of evidence capable of providing a point estimate for the value of distributed imputation credits to investors is market value studies. Evidence of utilisation rates (or potential utilisation rates, as indicated by the equity ownership approach) can only indicate the upper bound for investors' valuation of imputation credits. The conceptual goalposts approach referred to by the AER provides no relevant information on the actual value of credits;
- The best estimate of investors' valuation of imputation credits from market value studies is 0.35.

Combining a distribution rate of 0.7 with a theta estimate of 0.35 produces a value for gamma of 0.25, which differs from the AER's gamma estimate as outlined in the final rate of return guideline. Endeavour Energy's reasons for proposing a different value for theta to that in the Rate of Return Guidelines are outlined in the supporting attachments to this chapter, including SFG's latest report addressing the value of imputation credits.[149]

[149] {Generic GAMMA attachment and SFG attachment}

8 ALTERNATIVE CONTROL SERVICES

Summary

The AER regulates our public lighting services, ancillary (or non-routine) services, and elements of our metering service separately from our standard control services. The AER sets a price cap for these services. Our proposed prices reflect the efficient costs of providing the service.

In this chapter we set out our proposed prices for alternative control services identified by the AER. These services are considered to be separate from our standard control services, and result in customers getting an individual price for the service we offer rather than the costs being bundled as part of the network charge. The key points of this chapter are:

1. **We have proposed public lighting prices using a methodology similar to that developed by the AER last period**

Our proposed prices for public lighting have considered the capital, operating and implementation costs of providing elements of our service. We have used a similar method to that determined by the AER in the 2009 determination. Based on the current number and mix of street lights for each council our plan is to keep our increase in the total streetlight bill to CPI for the next five years.

2. **Our proposed metering prices will be based on the metering service that a customer has installed on its premises**

Customers will have a separate tariff for metering services depending on the service received. In developing prices, we have considered the revenue we need to fund future expenditure and investment in metering undertaken in the past.

3. **Our proposed prices for each ancillary network service will reflect the efficient costs of providing the service**

We have more than 52 non-routine services we provide our customer base. In the past the customer paid a small portion of the cost of providing the service, with the residual collected from the general customer base. The AER now considers that customers should face the full cost reflective charge for these services.

Endeavour Energy

8 ALTERNATIVE CONTROL SERVICES

Public lighting

Our proposed approach to public lighting services is consistent with that of the last control period. Our public lighting customers will continue to pay a fixed charge for assets installed before 2009, and an annual annuity charge for capital and maintenance costs by asset type installed after 2009. Based on the current number and mix of street lights for each council our plan is to keep our increase in the total streetlight bill to CPI for the next five years.

In this section we identify the method by which we have developed prices for the public lighting services we provide our customers. Our public lighting proposal (Attachment 8.02) provides additional details on the different types of lighting installations, emerging issues and initiatives, our expenditure forecasts and supporting information including profitability analysis and benchmarks. Our public lighting prices are listed in Attachment 0.16.

About our public lighting services

Public lighting is important in providing safety and security for pedestrians and vehicle traffic as well as enhancing the visual environment. Endeavour Energy is committed to providing public lighting services that effectively and efficiently meet the needs of our customers.

Public lights are typically installed in street locations including residential streets and main roads using existing electricity poles or on specific public lighting poles (often referred to as “columns”). The type of lighting required depends upon the road type and customer requirements.

Endeavour Energy currently serves 29 public lighting customers, including 23 local councils, with over 196,000 installed lights. The number of public lights is steadily increasing at around 2.5% per annum. This growth is due mainly to installations for new subdivisions and infill lighting for councils. We are not anticipating any change in the number of public lighting customers over the 2014 regulatory control period.

In line with relevant Australian Standards, there are broadly three types of public lighting services:

- main roads – for public safety reasons main road lighting standards require higher light output (lumens) and therefore require higher wattage lamps. This “V” category represents around 2 per cent of installations.
- minor roads – have lower wattage lamps than main roads. This “P” category represents around 98 per cent of installations.
- other public places – this includes parks and other public areas. This represents a relatively small portion of installations.

Lighting services may also be provided for private property using public lighting assets (supports) – for example public buildings, sports arenas, shopping centres and car yards. These services are provided as separate unregulated shared asset services and are outside the scope of the AER’s regulation of alternative control of public lighting services and covered through the shared assets guideline.

The majority of public lighting construction projects are contestable, in which case the public lights may be installed by a customer or gifted through land development protocols. Once completed and operating, Endeavour Energy is responsible for the ongoing maintenance and repair of the lights. We also directly undertake the construction of minor public lighting works and other public lighting projects at the customer’s request.

8 ALTERNATIVE CONTROL SERVICES

Legislation, regulations, standards and codes

Endeavour abides by the following legislation, regulations, standards and codes when installing and maintaining public lighting:

- NSW Public Lighting Code
- Customer nominated requirements within the range of services offered
- AS/NZS1158 series of standards for lighting of roads and public places
- Electricity Supply Act 1995
- Endeavour Energy electrical safety rules
- Endeavour Energy company policy 9.2.13 – property tenure for network assets
- Endeavour Energy company policy 9.6.8 – public lighting
- Guide to Traffic Engineering Practice – roadway lighting, HB 69/12 (Austroads)
- SPJ 4004, Section 6 – Endeavour Energy's *General Terms and Conditions* for connection of public lighting assets.

NSW Public Lighting Code

The service performance standard agreed between providers and public lighting customers of public lighting activities is set out in the industry NSW Public Lighting Code dated 1 January 2006. This Code seeks to provide a basis for expected service quality by DNSPs. The Code references the Australian Standard (AS1158) for public lighting which details illumination and other technical requirements. Compliance with the Code is not a licence condition under the NSW Electricity Supply Act 1995. The Code is non mandatory and provides a basis from which DNSPs and public lighting customers may wish to negotiate alternative service performance and pricing outcomes.

Endeavour Energy adheres to the minimum standards and guaranteed service levels set out in the Code in formulating the total costs in this regulatory proposal. In summary, the Code's key maintenance program requirements are:

- Outage detection and service availability requirements;
- Lamp replacement and disposal;
- Luminaire cleaning and inspection;
- Vegetation management strategies, including informing customers of their responsibilities;
- Inspection, test, repair, and replacement of equipment;
- Condition monitoring;
- Maintenance recording and performance review, and
- Modifications of maintenance program as required.

Another requirement of the Code is for each public lighting provider to prepare a Public Lighting Management Plan (PLMP) setting out how performance requirements will be met and providing a framework for ongoing public performance reporting. Endeavour Energy addresses each of the requirements listed above in its 2011 PLMP.

The Code also covers Service Level Agreements (SLAs). Although Endeavour Energy does not currently have any agreed individual SLAs with its customers, such agreements may be struck in the future to reflect the changing needs of our customers and recognising the fact that not all customers may wish the same service/price outcomes.

Engagement with public lighting customers

Endeavour Energy has undertaken extensive consultation with its public lighting customers individually and in groups, generally in Regional Organisation of Council collectives. This consultation has been extended beyond the regular meetings twice a year with each council in our network area in order to engage directly with the regulatory issues to be addressed in this proposal and by the AER in its decisions.

8 ALTERNATIVE CONTROL SERVICES

This engagement has been critical for Endeavour Energy to understand the specific needs of our customers as well as receive feedback from them on our performance over the current regualtory period. This engagement is to ensure we appropriately address in this proposal matters raised in submissions and representations from NSW councils at AER forums.

As summarisied in Attachments 2.09, the response from public lighting customers within our network area has been positive. They have been broadly supportive of our plan to contain our share of total street lighting costs to no more than CPI for the next five years. Further, we received positive reviews of our performance against service quality standards as per the NSW Public Lighting Code.

What we have heard more broadly from the various discussions with councils include:

- need for pricing stability
- pricing structure simplicity
- pricing structure transparency
- improving technology options
- streamlined approval process for the introduction of new tariffs
- adherence to minimum service outcomes, such as those incorporated into the NSW Public Lighting Code.

After discussing the upcoming reset with our councils in addition to our regular meetings twice a year, Endeavour Energy is aware that not all issues are relevant to all DNSPs or to the same degree. Consequently, we have approached our public lighting proposal to address the issues that are most pressing for our customers as well as ensuring that those aspects of our service that they are happy with are preserved.

A key issue for all users of electricity is the rate at which prices move. While customers generally accept that prices must reflect the underlying investment in the service they utilise, the need for sudden changes in investment levels is far less appreciated. Endeavour Energy has strived to constrain our share of network bills for electricity consumers to at or below CPI. We have also sought to contain our share of total street lighting costs to no more than CPI for the next five years.

For the 2009-14 period, Endeavour Energy instituted component based pricing, this established a price for each component type that could be used in a single installation. In doing so, we sought to limit the multitude of tariff combinations to simply those of the individual elements. This was designed to keep the pricing structures both simple and transparent while offering our customers the greatest degree of flexibility in the choice of components for any individual installation, and did not require a whole installation tariff to be totally changed if one component was upgraded.

The introduction of new technologies and associated tariffs has proven to be challenging over the current regulatory period, with AER approval being required when a new technology option is being adopted by one of our customers for which we do not currently have a suitable price. We are hopeful that the public lighting model attached to this regulatory proposal is sufficiently transparent such that Endeavour Energy and the councils using our public lighting services can quickly agree to pricing outcomes based on the component acquisition cost and associated maintenance costs. Where there is agreement we expect that the AER will be able to undertake an expedited approval process.

In respect to adherence to minimum levels of service standards as those provided for under the NSW Public Lighting Code, Endeavour Energy has explicitly sought out feedback from our customers regarding their service experience. Feedback received to date has been positive, with only minor unrelated exceptions to adherence to the standards being reported. As part of this regulatory proposal, Endeavour Energy proposes to continue targeting the standards set out by the Public Lighting Code.

Based on the feedback received from councils we are satisfied that we have been communicating with our customers in a manner that meets their requirements and that our service performance is commensurate with our pricing offerings. We propose to continue the existing arrangements to the extent possible where they satisfy our customers' needs.

Strategic objectives of public lighting

Every cost or investment decision in public lighting can be linked back to our strategic objectives. These are what we use to ensure our investment is in the best interest of our customers. The strategic objectives have been developed through consultation with our customers and using the Public Lighting Code.

Minimise total lifetime cost to our customers

The provision of public lighting includes both capital and maintenance charges as well street lighting use of system (SLUOS) charges. In order to provide the best value for money service to the customer, we need to consider all three charges over the lifetime of assets when choosing technologies and service delivery strategies.

Furthermore, ensuring that Endeavour Energy operates prudently and efficiently is fundamental to providing the required service at the lowest cost. This includes improving labour productivity, considering market-delivered solutions and reducing our overheads.

The proposed expenditure for the 2014-19 regulatory period is provided in Attachment 8.02. Expenditure increases for the 2014-19 regulatory period are due to:

- real increases in input costs, such as direct labour
- an increase in the scale of public lighting activities such as increases in the replacement of steel columns and luminaries.

Endeavour Energy's focus on managing cost inputs and undertaking efficiency initiatives is expected to limit the impact of external market forces on the overall costs of our public lighting services.

Maintaining network performance as described in the Public Lighting Code

The most significant public lighting service obligations imposed on Endeavour Energy that materially impact public lighting expenditure include:

- the NSW Public Lighting Code
- Australian Standard (AS/NZS1158) Lighting for Roads and Public Spaces and the nominated design requirements of individual customers.

The Public Lighting Code is the principal source of obligations for customer service performance for public lighting. It is a voluntary code that was introduced to help clarify the relationship between public lighting service providers and customers and sets out benchmarks to assist local councils. The existing Endeavour Energy public lighting systems and processes are designed to satisfy the Public Lighting Code.

Endeavour Energy proposes to comply with the Public Lighting Code for the 2014-19 period. We are not proposing to alter the public lighting service standard performance from the current levels. Service level performance for the 2014-19 period is forecast to remain at the current levels provided we are allowed revenues sufficient to meet the described expenditure requirements.

Maintaining customer performance as described in the Public Lighting Code

Endeavour Energy has implemented a public lighting compliance framework to satisfy the service standards described in the Code. Elements of the framework include:

- operating a 24 hour call centre to receive fault reports from customers
- establishing a management plan and reporting system for the design and construction of public lighting assets

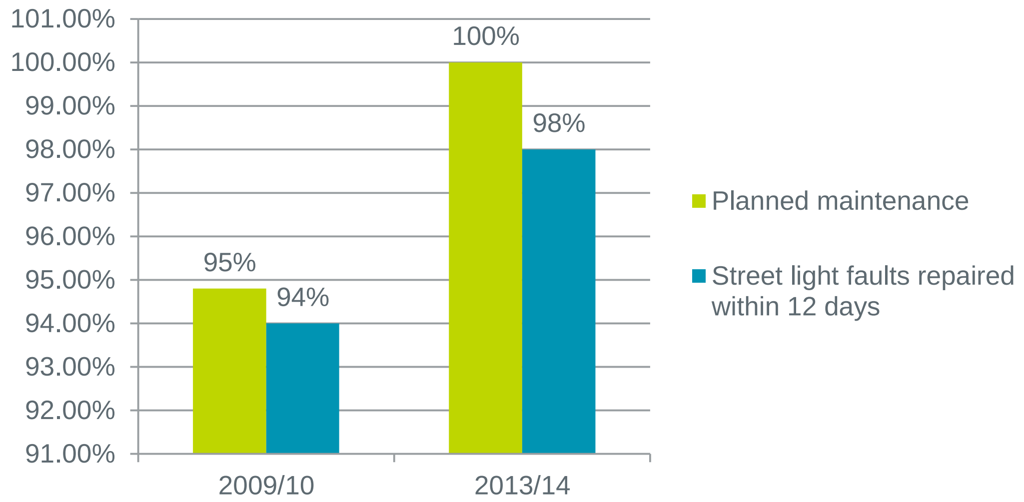
- managing and monitoring the bulk lamp replacement program to ensure efficient and safe operation of the system to achieve agreed maintenance standards and to maintain the designed lighting technical parameters of the luminaire;
- cleaning, inspecting and repairing luminaires during re-lamping
- ensuring that repairs of public lighting assets are undertaken within an average of eight working days per customer per year from receipt of the reported fault
- endeavouring to provide repairs more quickly in high priority cases
- supplying reports to all major customers.

Endeavour Energy has a 24 hour call centre to receive calls from customers about faults and emergencies including public lighting calls. We also have an online form to allow customers to notify of public lighting problems via the internet.

Our bulk lamp replacement program is designed to ensure efficient and safe operation of the public lighting system to achieve agreed maintenance standards and to maintain the designed lighting technical parameters of the luminaire. This program includes cleaning, inspecting and repairing luminaires during re lamping.

Substantial improvements have been made during the current regulatory period through centralised street light maintenance and a dedicated resource provided for the purpose. It has been possible to achieve the program targets as indicated in Figure 24 below:

Figure 24: Maintenance and fault repair activities



At present Endeavour Energy submits five types of reports to its customers as listed below:

Type of report	Frequency of report
Progress on design and construction projects	Quarterly
Bulk lamp change	Quarterly
Maintenance performance	Annually
GIS and public lighting inventory	Six monthly
Customer service guarantee payments	Annually

8 ALTERNATIVE CONTROL SERVICES

Endeavour Energy's public lighting repair time at present is 3.8 working days average as against the Code requirement of eight working days. Endeavour Energy expects to maintain this current level of service performance for the next regulatory period.

Method of developing public lighting prices

Endeavour Energy proposes to continue applying the current tariff structures and component based pricing over the next regulatory period, based on supportive feedback provided by councils in our network area on the current structures. The tariff classes are broken down into two key subgroups, tariffs for assets installed before 1 July 2009 and those after this date.

The differentiation of investments around this date is critical due to the need to preserve the price and value outcomes of the previous regulator IPART, whilst allowing the AER to seek to introduce price and service reforms for new assets moving forward. Failure to apply this transitional approach would likely have led to significant value, pricing equity and bill shock issues for our customers.

Broadly speaking Endeavour Energy currently has six tariff classes, being:

1. **Tariff class 1** is an aggregate capital recovery and maintenance tariff. This applies where the asset was initially funded by Endeavour Energy and was included as part of the RAB determined by IPART prior to 1 July 2009. Capital cost recovery built into this tariff class will trend in line with the residual RAB value reducing over time and historical price escalation constraints. However, it is also worth noting that the values used to set the prices in 2009 were necessarily averaged and were unlikely to reflect the nature of each specific lighting installation for each individual customer.

   It is expected that as the original RAB value depreciates down to zero that all capital charges in this tariff class will cease over time making this tariff class ultimately redundant. Assets priced under tariff class 1 may sometimes also be referred to as legacy assets.

2. **Tariff class 2** is a maintenance cost recovery only tariff. This applies to assets where Endeavour Energy did not fund the initial construction which occurred prior to 1 July 2009. As Endeavour Energy did not fund the construction it is not entitled to any capital recovery charges for these assets. Similarly with tariff class 1 above, as assets in this category are replaced over time this tariff class will eventually become redundant. Assets priced under tariff class 2 may sometimes also be referred to as legacy assets. Historical pricing constraints may also apply.

3. **Tariff class 3** is an aggregate capital recovery and maintenance tariff similar to tariff class 1, however this tariff class is priced using an annuity approach and only applies to assets installed after 1 July 2009. Unlike tariff class 1 there is no RAB value driving variable prices over time and is specific to the asset installed.

4. **Tariff class 4** is a two part tariff, the first element is a maintenance cost recovery only charge similar to tariff class 2. This applies to assets where Endeavour Energy did not fund their initial construction which occurred after 1 July 2009. As Endeavour Energy did not fund the construction it is not entitled to any capital recovery charges for these assets. Endeavour Energy however, is required to pay income tax on assets gifted to us in this manner.

   Therefore the second element of tariff class 4 is a tax cost recovery charge that is paid through an annual amount over the life of an asset that is gifted to Endeavour Energy by our customers after 1 July 2009.

   When an asset is gifted to Endeavour Energy it is required to pay income tax on the fair value of the asset. This income tax payment is irrespective of the fact that Endeavour Energy is not permitted to recover revenues related to capital expenditure on assets that it did not incur.

   Consistent with the residual maintenance objectives inherent in the AER's PTRM Endeavour Energy has established tariffs for current assets that may be installed that seeks to recover the NPV difference between the income tax paid in the year the asset is gifted to Endeavor Energy and the depreciation income tax deductions that it can claim over the life of the asset when in service.

5. **Tariff class 5** is a pure capital recovery tariff that is paid in a lump sum at the time of agreeing to replace an asset before the end of its useful life. This tariff class does not have specified prices but rather a specified formula for calculating the residual unrecovered capital and tax costs when a customer requests an early replacement of assets paid for by Endeavour Energy.

   The asset specific charge is calculated by the DNSP at the time of agreeing to replace the asset early using cost recovery method. The residual asset value charge calculated for an early replaced asset is based on the remaining life determined through an assessment of the assets condition and/or type or the AER default value.

6. In addition to the five tariff classes detailed above, the unregulated tariff class will apply where customers request limited maintenance only services to non-standard public lighting assets that they own and are responsible for. The rates are cost reflective for luminaire only requirements.

The provision of public lighting services faces a number of future challenges that will have a profound effect on public lighting products and services. New technologies such as LED lighting solutions, improved designs, and improved consultation and information sharing with customers are all expected to deliver improved outcomes to public lighting customers and the public in general.

Costs

There are four main costs in providing public lighting services: capital, operating costs, process improvement costs and corporate overheads. These costs are set out in detail in Attachment 8.02.

- Capital costs. These refer to costs relating to the installation of public lighting assets either for brand new connections or replacing assets due to poor performance or being made obsolete due to new technology. Capital costs include the purchase of the physical items being installed and the capitalisation of labour costs required to undertake the installation.
- Operational costs. These refer to the ongoing costs to maintain/repair the installed assets as well as the replacement of lamps for each installation at appropriate intervals.
- Process improvements. These involve investing in systems which improve the way the public lighting business is operated, resulting in lower costs for all or improved service. These have the effect of improving maintenance charges and/or service outcomes for our customers.
- Overheads. These relate to the operational and strategic support costs such as IT systems to support asset and billing information, safety management, procurement activities etc.

Compliance with control mechanism

The Rules require that a regulatory proposal include:

- the proposed control mechanism
- a demonstration of the application of the proposed control mechanism
- the necessary supporting information for alternative control services.

In compliance with the Rules, Endeavour Energy proposes the following forms of control for public lighting services over the 2014-19 regulatory period consistent with the AER's F&A decision:

- a schedule of fixed prices for public lighting services for the first year of the regulatory period
- a price path for the remaining years of the regulatory control period, based on the CPI-X methodology contained in the submitted public lighting model.

8 ALTERNATIVE CONTROL SERVICES

Metering services

In this section we outline our proposed pricing for metering services. We identify what meters and related services are subject to pricing regulation by the AER, how we developed prices, and the charge our customers would expect to pay depending on the metering service received.

About our metering services

Metering services are a new class of service developed by the AER in response to policy changes designed to expand competition into previously monopoly activities. Metering services encompass a range of activities currently provided by NSW distribution businesses. The AER has divided metering services into three categories:

- Metering Installation Types 1, 2, 3 and 4 which are currently unregulated
- Metering Installation Types 5 and 6 which are currently regulated and are included as part of the distribution charges
- Metering Installation Type 7 (no meter) which are currently regulated and are included as part of the distribution charges.[150]

From 1 July 2014, the AER proposes to separately regulate and price the metering services associated with type 5 and 6 metering installations provided by NSW distribution businesses and are the focus of this section.

Type 5 metering installations or interval type metering record energy in 30-minute intervals, without the requirement to remotely acquire the data. Typically, these meters are read every three months, sometimes monthly.[151] Often the term MRIM (manually read interval meter) is used interchangeably for a type 5 meter. A type 5 metering installation however, is not the same as a Smart Meter[152] installation.

A type 6 metering installation is defined as a 'general purpose' meter that records accumulated energy data only.[153] The term 'basic meter', accumulation meter and type 6 meter can be used interchangeably.

Endeavour Energy's existing meters are predominantly basic accumulation (type 6) meters, so the issue of significant cross-subsidisation among customers due to technology choice is not significant. Few customers have type 5 meters. These are not smart meters but they do capture more detail about usage than type 6.

During the F&A process we raised some concerns about whether unbundling might lead to customer confusion, but we have nonetheless undertaken a process to separate metering services from standard control services, and develop cost reflective prices.

Our new arrangements will promote greater cost visibility by introducing a separate charge or charges for ongoing capital and operating costs. As the pricing of metering services is simply a reclassification of services and costs, Endeavour Energy will not gain any additiional revenue than would be allowed by the AER if these services had remained bundled in the distribution charges.

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[150] A Type 7 metering installation applies to the condition where it has been determined by AEMO that the metering installation does not require a meter. Examples may include, street, traffic, park, and community lighting, traffic parking meters. Metering data services associated with Type 7 metering will remain part of standard control services

[151] The time between meter reads is normally a function of the network tariff applicable to a customer's premises.

[152] The National Electricity Law defines *smart metering infrastructure* as "infrastructure (and associated systems) associated with the installation and operation of remotely read electricity metering and communications, including interval meters designed to transmit data to, and receive data from, a remote locality.

[153] Processes used to convert the *accumulated metering data* into *trading interval metering data* for settlements purposes are included in the *metrology procedure.*

8 ALTERNATIVE CONTROL SERVICES

We wish to give effect to the AER's change in classification to ensure our charges are based on the actual services customers receive. A detailed description of our proposed pricing methodology and how we have sought to facilitate the AER policy intent behind these changes appears in Attachment 8.10.

Strategic objectives of metering services

Endeavour Energy's overall objective of ensuring investment is prudent and efficient for the required outcome has led to the following business objectives governing the provision of type 5 and 6 metering services:

- metering is safe and accurate
- metering equipment supports network pricing strategies
- able to support network pricing strategy
- able to support the network load control strategy
- able to support any related market or customer objectives identified as within the network business scope.

Method to develop pricing for metering services

The AER has specified that the control mechanism which applies to these services is a cap on prices. In giving effect to this requirement we have sought to develop prices that meet the following principles:

- Facilitates customer choice. This means providing realistic prices to customers at the time of purchase. As far as practical we will seek to avoid the need for exit charges to facilitate competition.
- Cost reflective. To ensure that customers make informed decisions we have developed prices that truly reflect our costs. We have established the prices by reference to our historical expenditure and expert judgment where necessary.
- Equitable. Our approach seeks to eliminate the possibility of cross subsidisation. We are proposing arrangements that provide price signals to those customers that make active decisions regarding their metering services. This will protect customers from inappropriate pricing arrangements where their metering installation is inherited from previous decisions. Our approach seeks to eliminate the existing residual regulatory asset base value and provide information for customer decision making from this point forward.
- Administratively simple. Our approach has been developed within the constraints of a start date of 1 July 2015 and our existing IT and billing capabilities. We have sought to avoid an approach requiring significant implementation costs or an approach requiring significant and costly ongoing reporting and reconciliation requirements. Our approach should provide customers with simple, transparent information.

To develop a cost-reflective price, we have examined our historical costs to determine what drives our metering costs. A full explanation of our methodology and supporting material can be found in Attachments 0.17, 8.09 and 8.10.

To summarise, as a large proportion of our costs are fixed and National Metering Identifier (NMI)-based, we have split services between primary and secondary categories. The latter are metering services that are in addition to the basic network service most customers receive, such as off-peak hot water or solar PV meter services. These additional services result in only marginally higher overall costs and therefore attract a lower incremental charge.

This means that a customer will pay a greater amount for their first metering service as this creates the majority of costs we incur as their meter provider. This approach also ensures that customers who have more metering services than a basic accumulation service will pay more to reflect the additional services being provided. We have tried to develop an approach that balances the need for cost reflectivity while providing a fair and appropriate price for the service a customer is receiving.

Proposed prices for the 2014-19 period

Our approach involves the following:

- Existing meters. We will seek to recover the existing capital costs for type 5 and 6 meters during the course of the 2014-19 period. The average charge will be $4.33 p.a. for each customer
- New meters. The capital costs for a meter upgrade, additional meter at an existing site or a new meter at a new customer site (new meters) will be added to the installation cost that customers currently pay upfront to their Accredited Service Provider (ASP). This is our existing practice for non-standard meters and will be extended to standard meters
- Operating and replacement expenditure. Ongoing costs such as maintenance, meter reading, meter testing, data service and meter replacement costs will be recovered via a cents per day charge.

The collection of existing meter costs will be on a per-customer basis to avoid penalising customers for past decisions and is broadly consistent with the current arrangements. We plan to do this over the remainder of the period (from 2015-16) so as to minimise and smooth the pricing impact on customers. Our approach seeks to eliminate the existing residual value within the 2014-19 period in order to facilitate a movement towards competition.

The prices for ongoing operating and replacement expenditure have been developed on a per-service basis. This means that each unique data stream will attract a price. For example, a basic metering charge and an off-peak metering charge equates to two data streams and two services. We have used this approach to develop prices which reflect the service and benefit customers are receiving from their perspective. Our prices are therefore as follows:

8 ALTERNATIVE CONTROL SERVICES

Table 39: Ongoing metering prices

$p.a; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19
Residential anytime	$25.16	$26.20	$27.12	$27.15	$29.15
Residential TOU – type 6 meter	$46.85	$48.54	$50.68	$51.17	$54.09
Residential TOU – type 5 meter	$175.72	$180.27	$188.93	$191.31	$198.82
Small business anytime	$34.55	$35.94	$37.45	$37.74	$40.20
Small business TOU – type 6 meter	$75.02	$77.78	$81.67	$82.92	$87.24
Small business TOU – type 5 meter	$203.89	$209.51	$219.92	$223.06	$231.98
Controlled load	$11.35	$12.09	$12.33	$12.16	$13.68
Solar	$11.35	$12.09	$12.33	$12.16	$13.68

Table 40: New meter prices

$m; Nominal	Price
A single phase accumulation meter	$41.85
A single phase accumulation combination meter	$180.74
A three phase accumulation meter	$114.20
A single phase interval (TOU capable) meter	$335.80
A three phase interval (TOU capable) combination meter	$381.47
A three phase interval (TOU capable) meter	$459.00

Additionally, the Standing Council on Energy and Resources (SCER) metering rule change request is currently under consultation. This rule change seeks to increase competition in metering and related services. In the event of competition we will incur administrative costs and stranded asset costs. In light of this, we propose exit fees the 2014-19 period as per the table below. This is to ensure our customers do not cross subsidise the costs of competition.

Table 41: Proposed exit fee

$m; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19
Opening RAB recovery	$16.89	$13.98	$10.95	$7.69	$4.08
Administration cost	$50.49	$51.76	$53.05	$54.38	$55.74
Proposed exit fee	**$67.39**	**$65.74**	**$64.00**	**$62.06**	**$59.81**

Please see Attachments 0.17 and 8.10 for a detailed description of our pricing methodology and price list. Also, see Attachment 8.09, a report from Energeia, which examined the reasonableness of our pricing approach and outcomes. We have developed these prices with the goal of ensuring our CPI price path promise to customers is satisfied.

8 ALTERNATIVE CONTROL SERVICES

Ancillary network services

In this section we explain what ancillary network services are and the methodology we have used to set prices for these services. Attachment 8.12 provides further information on the activities undertaken to provide each ancillary network service and their costs.

About our ancillary network services

The AER has proposed to create a group of services called ancillary network services to capture non-routine services provided to customers on an as-needed basis. Examples of such services include providing customer design related information, special meter readings and after-hours service provision.

This class of service was grouped as 'miscellaneous and monopoly' services during the 2009-14 regulatory period. It will also include incidental services and, potentially, new distribution services which Endeavour Energy has identified as being necessary to satisfy the National Energy Customer Framework's requirements.

As the nature of service involves work on or in relation to parts of Endeavour Energy's distribution network, the AER proposes to classify ancillary network services as direct control services. The AER has proposed that these should be further classified as alternative control services, as the costs of such services can be directly attributed to an individual or small group of customers.

Method used to develop prices

As with metering services, the AER wishes for a cost-reflective price to be developed that ensures standard control customers do not subsidise these activities specific to a small sub-set of customers. We have therefore developed our rates based on the our historical hours and costs. For new services we have developed an estimate of hours and costs based on a bottom-up forecasting process.

It should be noted that the prices for many of these services were originally set by IPART in our 1999 determination. Since that time, costs have been indexed to inflation every five years and not reviewed in detail. As such, many of these services have been historically under-costed and subsidised by our standard control services. The change in classification recognises this issue and our goal has been to fully cost and separate these non-standard services.

To calculate the unit rates for each of the ancillary network services, one of the following methodologies were used:

1. Historical averages

For a large portion of ancillary network services we have established accounting systems to capture direct operating costs associated with each category. For those services we extracted three years of historical data to identify the types of employees who were involved in each of the ancillary network services.

For each of the three years, the total operating costs (predominantly labour) were divided by labour hours to derive an average hourly rate. Each of these hourly rates was converted into 2012-13 dollars and an average for the three years was developed. This hourly rate was then combined with the standard hours for each activity to achieve the individual unit rates within each category.

2. Bottom-up approach

For services where we were unable to reliably extract cost and activity data, a bottom up approach was used. This was particularly the case for new ancillary network services for which we do not currently have a price. In these instances, the type of employee who carried out the service was identified, an average hourly rate was determined and an estimate provided for the average time it took to carry out that service. These direct unit rates were then applied to the applicable ancillary network service.

3. Operating costs divided by volumes

In some instances we were able to determine the estimated total operating costs associated with a particular service. To determine the unit rates for these services the total direct operating costs were divided by the appropriate volume driver.

The remaining network operating costs that could not be allocated directly are network overheads and these were allocated to service categories based on a non-causal allocator. Once the overhead percentage for ancillary network services was determined according to our Cost Allocation Methodology (CAM), this was added to our direct unit rates.

Please refer to Attachment 8.09 for a more detailed view of our pricing methodology and forecasts. We also engaged KPMG to review our pricing models for accuracy, see Attachment 8.08 for their report.

Proposed prices for the 2014-19 period

For a full schedule of our ancillary network service rates, please refer to Attachment 0.18.

9 PRICING ARRANGEMENTS AND NEGOTIATED FRAMEWORK

Summary

This chapter is to identify our approach on tariff design for the 2014-19 period, and the reporting arrangements for our annual pricing proposal. We also identify our negotiating framework.

Our network tariffs account for approximately 40 to 50% of a typical customer's electricity bill. While the focus is on recovering our allowed revenue, we also collect revenue to make payments to other parties. For the 2014-19 proposal, our network tariffs will incorporate the following types of charges:

- Distribution charges. This will enable recovery of the revenue we are permitted to collect for the standard control services provided by our distribution assets.
- Specific charges for metering. This will allow us to recover our efficient costs for the provision, maintenance, reading and data services of type 5 and 6 meters, noting that the price a customer pays will depend on the meter installed.
- Designated pricing proposal charges. These primarily relate to payments we make to TransGrid for the use of its transmission network in NSW.[154]
- Jurisdictional scheme charges. These relate to the recovery of revenue to accommodate pass through of jurisdictional scheme amounts for approved jurisdictional schemes. Currently, this relates to payments we make to the Climate Change Fund.[155]

How we design our network tariffs

The integrated nature of electricity means that we cannot establish a unique 'cost reflective' price for each individual customer for our standard control services. As a result, we develop network tariffs for segments of customers that reflect a fair share of the costs of servicing a customer in that segment.

Our tariffs are designed around different types of customers, for instance residential, small business, and large businesses. Our tariff structures also vary depending on the type of meter installed at the customer's premises. For instance, interval meters (type 5) enable us to charge customers a price depending on the time they use electricity (time of use pricing).

Our annual pricing proposal sets out the proposed tariffs to apply for each regulatory year. When we develop our charges (tariffs) for each customer, we seek to meet the following principles:

- Equity. This means that customers pay prices that reflect their proportionate use of the network.
- Efficient use of our network that benefits all customers. This means designing tariffs to ensure that the network is used to its efficient capacity. For example, customers with interval meters are subject to different prices depending on whether energy is used at peak or off-peak times. This has the benefit of providing pricing signals that reflect usage and potentially avoid the need to undertake inefficient capacity investment.

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[154] In addition to these charges, our network tariffs need to recover payments for avoided customer TUOS payments; and payments we make to other DNSPs for the use of their network.

[155] The Climate Change Fund established under the Energy and Utilities Administration Act 1987 (NSW).

9 PRICING ARRANGEMENTS AND NEGOTIATED FRAMEWORK

Assigning customers to tariff classes

In developing our network tariffs for the annual pricing proposal, we are required to consider a number of factors on how we assign customers to a tariff class. This is to ensure that customers are grouped together in a way that is economically efficient, while minimising unnecessary transaction costs.

To assist the AER in making its decision, Attachment 9.02 sets out our proposed procedures for assigning customers to tariff classes, or reassigning customers from one tariff class to another. Our proposed procedure is consistent with the principles outlined in clause 6.18.4 of the NER and is determined as follows:

- customer type, taking into account supply voltage and annual consumption;
- whether the connection is existing or new; and
- the type of meter installed at the connection point.

New tariff designs for 2014-19 period

For the 2014-19 period, we will be making some changes to our tariff design for customers to better meet our principles of efficiency and equity. Our vision is to move towards prices that better reflect the underlying costs of supplying network services and capacity, while constraining price increases on average.

In re-designing our tariffs, we have been particularly careful that our customers do not experience unreasonable bill outcomes from any changes, and that prices are equitable and stable over the period. Our tariff strategy is based around recovering a lesser proportion of revenue through volatile energy-based tariffs components.

This reflects that the majority of our efficient costs, such as the ongoing financing costs for previous investment, are fixed. Further, given the trend of volatile and declining volume consumption, continued reliance on inclining block tariffs for residential and small business customers is likely to lead to pricing volatility throughout the regulatory period as we are obligated to set prices to recover allowed revenues under the revenue cap.

Reporting arrangements for pricing proposals

The AER has a role in monitoring whether we comply with the controls it applies to our regulated services. For this reason the AER is required to make a number of upfront decisions in its regulatory determination on how a DNSP is to approach pricing, and how it reports on compliance during the course of the 2014-19 period.

For the most part, these decisions relate to the preparation of our network tariffs as part of our annual pricing proposal. In the sections below we describe why the AER has to make each of its decisions, and our proposed method or approach.

Compliance with control mechanism

The AER is required to make a decision on how compliance with a relevant control mechanism is to be demonstrated. Our proposed approach on demonstrating compliance for each control mechanism is as follows:

- for alternative control services, we consider that our published price lists be the vehicle to demonstrate compliance with the price cap formulae in the control mechanism

- for each type of standard control service, we consider that the pricing proposal would need to show that the forecast revenue to be collected for these services should be equal to the maximum allowed revenue in the control mechanism.

The AER's F&A Stage 1 paper sets out the following formula for control of standard control services revenue.

Maximum Allowed Revenue $_t$ = Annual Smoothed Revenue$_t$ + I_t + T_t + B_t

The maximum allowed revenue for standard control services includes additional revenue increments relating to incentive schemes ("I" adjustment), adjustments for the transitional regulatory year ("T" adjustment), and adjustments from under-over recovery in previous years (contained in the "B" revenue adjustment). The latter issue arises when actual energy consumption is different to forecast volumes, leading to over or under recovery. We note that the issue of under and over recovery will only arise for the standard control services provided by our distribution network.[156]

The AER's final rate of return guideline incorporates an approach to setting of the cost of debt that includes an annual update to the cost of debt. We agree with the annual update to the cost of debt and propose that for each regulatory year, the cost of debt allowance be updated in accordance with the 10 year trailing average approach. Our compliance model applies the formula specified in the AER's Stage 1 F&A paper. If the AER considers an additional factor or amendment to the formula or PTRM is required to give effect to the annual cost of debt update we will review this as part of our revised regulatory proposal.

We propose that the AER's mechanisms for under recovery or over recovery should be the same as that which applied for our transmission charges in the 2009-14 period. Additionally, we consider that it is in the best interests of our customers that we are allowed to set our distribution use of system tariffs to achieve a non-zero closing balance of the overs and unders accounts in period t. It is important that we have this flexibility under the revenue cap for standard control services to ensure that we can minimise volatility in prices between years and over the period.

Endeavour Energy provides an annual pricing compliance model as Attachment 9.01 and further information on proposed compliance at Attachment 9.03. These attachment provide more information on our proposed arrangements to demonstrate compliance with control mechanisms, including the under-over recovery mechanism.[157]

It is proposed that this model be used by Endeavour Energy to demonstrate annual compliance with the revenue cap control mechanism when submitting an annual pricing proposal to the AER. This model includes an under-over recovery mechanism for distribution prices, charges for the recovery of jurisdictional scheme amounts and designated pricing proposal charges and applies the formula for control of standard control services revenue as set out in the AER's F&A Stage 1 paper.

Reporting on recovery of designated pricing proposal charges and jurisdictional scheme amounts

Designated Pricing Proposal Charges include the transmission-related charges payable to TransGrid, avoided Transmission Use of System (TUOS) charges payable to certain generators, and inter-distributor payments. Jurisdictional scheme amounts are amounts which Endeavour Energy is required to pay under jurisdictional requirements. They have been recognised as amounts which may be recovered under the Rules as part of

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[156] As explained in the section on transmission pricing (see below), the arrangements for recovering our MAR for transmission standard control services are complex. The arrangements require us to collect revenue for all transmission services in NSW as part of designated pricing proposal charges, and pass this through to TransGrid. TransGrid will then provide a payment equivalent to our MAR, meaning there is no under or over recovery of this amount.

[157] NER clause S6.1.3(6)

9 PRICING ARRANGEMENTS AND NEGOTIATED FRAMEWORK

Endeavour Energy's pricing proposal. There are currently two jurisdictional schemes relevant to Endeavour Energy recognised in the NER. The first is the NSW Solar Bonus Scheme,[158] the second is the CCF.

Endeavour Energy proposes that the AER should use the same overs and unders account mechanism to report the recovery of designated pricing proposal charges and jurisdictional scheme amounts as has been used to report TUOS charges and the CCF payments during the 2009-14 regulatory period.

The proposed overs and unders account mechanism ensures that these charges and scheme amounts are passed through to customers in a manner that ensures that they pay no more or less than required.

The mechanism also includes an adjustment on outstanding balances that is consistent with the allowed rate of return. The over or under recovery calculated by this mechanism is passed through to customers via an adjustment in annual prices. It will be reported in the pricing compliance model submitted to the AER as part of the annual pricing proposal.

The proposed mechanism is included in Attachment 9.02 to this substantive regulatory proposal.

Negotiating Framework

As noted in Chapter 3 of our proposal, none of the services we currently provide are classified as negotiated distribution services. If required to provide such services in the course of the 2014-19 period, we will apply our proposed negotiating framework set out at Attachment 0.15. The negotiating framework has been prepared to comply with the requirements of Part D of Chapter 6 of the NER.

[158] During the 2009-2014 period all payments made under the NSW Solar Bonus Scheme have been recovered by NSW DNSPs through payments to and from NSW Climate Change Fund.

Endeavour Energy

ATTACHMENTS

Item No	Description
0.01	Customer overview: plain English summary - Affordable, safe and reliable electricity
0.02	Delivering efficiencies for our customers
0.03	Addressing the capex and opex objectives, criteria and factors
0.04	Escalation factors affecting expenditure forecasts (CEG)
0.05	Labour cost escalators for NSW, the ACT and Tasmania (Independent Economics)
0.06	Board certified key assumptions
0.07	Cost Allocation Methodology
0.08	Expenditure Forecasting Methodology
0.09	ICT Investment Plan
0.10	Proposed Connection Policy
0.11	Endeavour Energy Distribution Business Benchmarking Study (Huegin)
0.12	Addressing the benchmarking factor for capex and opex
0.13	Economic interpretation of Clauses 6.5.6 and 6.5.7 of the NER (NERA report)
0.14	Endeavour Energy STPIS Proposal
0.15	Endeavour Energy Negotiating Framework - Negotiated Distribution Services
0.16	Public Lighting Price List
0.17	Metering Model and prices
0.18	Ancillary Network Services Proposed Fees
0.19	Confidentiality Claim
0.20	Reference table for Rules Compliance
2.01	Customer Engagement Plan
2.02	Customer Engagement Study Qualitative and Quantitative Full Report - August 2013
2.03	Customer Engagement Survey Qualitative Summary Report - May 2013
2.04	Customer Engagement Survey Quantitative Summary Report - July 2013
2.05	Customer Priorities Data Review (IPSOS)
2.06	Consumer Engagement Report - April 2014
2.07	Networks NSW Social Media Campaign - YourPowerYourSay
2.08	Peak Consumer Group Forum Report (with appendices)
2.09	Local Council Engagement Report
2.10	Retailers' Forum Engagement Report and Presentation

ATTACHMENTS

Item No	Description
2.11	Stakeholder Correspondence Summary Report
3.01	Endeavour Energy classification proposal
4.01	RFM
4.02	PTRM – Substantive Proposal
4.03	EBSS model for 2010-2014
4.04	Forecast Customer Numbers, Energy Consumption and Billed Demand
4.05	Energy Forecasting Methodology Flowchart
4.06	Review of post modelling adjustments to the NSW DNSPs long term energy forecasts
4.07	Frontier Economics recommendations report on forecasting (including cover letter)
4.08	NIEIR Macroeconomic Projections December 2013
4.09	NIEIR Price & Elasticity Projections December 2013
4.10	Endeavour Energy Pass Through Event Proposal
5.01	Network Supply Strategy 2014-19
5.02	Network Management Plan
5.03	SAMP
5.04	SAMP Delivery Plan
5.05	TNPR
5.06	SARP
5.07	Augex model summary
5.08	Repex model review report
5.09	Annual Licence Compliance Reports (4)
5.10	Procurement strategy
5.11	Risk Management Plan
5.12	Company Procedure GFC 0056 - Investment Evaluations Manual
5.13	Company Policy 9.2.1 - Network Planning
5.14	Company Procedure GAM0035 - Major Projects Formulation and Approval
5.15	Company Policy GAM0013 - SAMP Project Management Capital Project Change Control
5.16	Distribution Annual Planning Report - 2013
5.17	Capital expenditure for previous, current and forecast period
5.18	Branch Procedure NFB0010 - Network Demand Forecasting – Summer and Winter Peak Demand Forecast Process

ATTACHMENTS

Item No	Description
5.19	Review of Endeavour Energy's method for peak demand forecasts (Spatial Peak)
5.20	Escalation Factors Endeavour Energy
5.21	Growth Servicing Strategy
5.22	Sample Business Case - Marsden Park Industrial Area
5.23	North West Sector Area Plan
5.24	South West Sector Area Plan
5.25	Greenfield Zone Substation Business Cases\
5.26	Distribution Works Program (including DSR)
5.27	Reliability Works Program
5.28	Reliability Plan
5.29	Quarterly Licence Compliance reports (19)
5.30	Reliability and Performance Licence Conditions for Electricity Distributors effective 1 July 2014
5.31	KPMG Prudency and efficiency review for Endeavour Energy's 2014-19 ICT Submission
5.32	Network Technology Strategy
5.33	FSC Strategy
5.34	Demand Management Strategy 2014-19
6.01	Network Reform Savings Register
6.02	Challenge and Compete Savings Register
6.03	Company Policy 6.11 - Capital Expenditure Measurement and Control
6.04	Company Procedure GFC0005 - Capital Expenditure
6.05	Company Policy 6.9 - Capital Expenditure - Overhead Calculation
6.06	Company Procedure GFC0034 - Budgeting and Forecasting
6.07	Company Policy 6.31 - Budgeting and Forecasting
6.08	Capitalised Overhead models (2014-15 to 2018-19)
6.09	Maintenance unit rate model
6.10	Allocation process (Methodology document on giving effect to the CAM)
6.11	Network Maintenance Implementation Plan
6.12	AER decision-Application for a retail project event nominated cost pass through
6.13	NSW DNSPs Review of regulatory treatment of risk (EY)
6.14	Operating expenditure for previous, current and forecast period
6.15	Operating expenditure – fixed vs. variable

ATTACHMENTS

Item No	Description
7.01	CEG - WACC estimates, a report for NSW DNSPs
7.02	CEG - Debt transition consistent with the NER and NEL
7.03	CEG - Efficiency of staggered debt issuance
7.04	CEG - Transition to a trailing average approach
7.05	UBS Advice to Networks NSW - October 2013
7.06	Kanangra - Credit Ratings for NSPs - 28 June 2013
7.07	Incenta - Debt raising costs - Endeavour
7.08	Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, UNDERSTANDING ASSET PRICES
7.09	NERA - The Fama-French Three-Factor Model - Oct 2013
7.10	SFG - Alternative versions of the dividend discount model and the implied cost of equity
7.11	SFG - Dividend discount model estimates of the cost of equity - 19 June 2013
7.12	NERA - The market size and value premiums - June 2013
7.13	NERA - The Market Risk Premium, Analysis in response to the AER's draft guideline - 11 Oct 2013
7.14	CEG - Estimating the return on the market - 28 June
7.15	CEG - Estimating the E[Rm] in the context of recent regulatory debate
7.16	SFG - Cost of equity in the Black Capital Asset Pricing Model - May 2014
7.17	NERA - Estimates of the zero beta premium - 27 June 2014
7.18	SFG - Equity beta - May 2014
7.19	SFG - Regression-based estimates of risk parameters for the benchmark firm
7.20	CEG - Information on equity beta from US companies
7.21	CEG - Equity beta issues paper International comparators
7.22	Comparison of OLS and LAD regression techniques for estimating beta - 26 June 2013
7.23	The Vasicek adjustment to beta estimates in the Capital Asset Pricing Model
7.24	Assessing the reliability of regression-based estimates of risk
7.25	SFG letter - Water utility beta estimation - 28 October 2013
7.26	Endeavour Energy Gamma Proposal
7.27	SFG - An appropriate regulatory estimate of gamma
7.28	NERA - Imputation Credits and Equity Prices and Returns
7.29	SFG - Updated dividend drop-off estimate of theta - 7 June 2013
7.30	NERA - The Payout Ratio - June 2013

ATTACHMENTS

Item No	Description
7.31	Hathaway - Imputation credit redemption data from the ATO 1988-2011
7.32	NSW DNSP Submission on the Rate of Return consultation paper - June 2013
7.33	NSW DNSP Submission to AER on the draft Rate of Return Guideline 11 Oct 2013
7.34	NNSW response to AER letter on cost of debt averaging periods 27 Feb 2014
8.01	Public lighting code - NSW 2006 Public Lighting Code
8.02	Public lighting proposal
8.03	Public lighting management plan
8.04	Public lighting modelling methodology
8.05	Public lighting model
8.06	Review of Endeavour Energy's Proposed Metering Tariff Arrangements for 2014-19 (Energeia)
8.07	Endeavour Energy's Approach to Pricing Types 5 & 6 Metering Services
8.08	KPMG report on Endeavour Energy ANS approach
8.09	ANS Fee Methodologies
8.10	Alternative Control Services true up mechanism
9.01	Compliance Model
9.02	Assigning customers to tariff classes
9.03	Compliance with Control Mechanisms

GLOSSARY

Term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
Augex	Augmentation expenditure model
CAM	Cost allocation method
CAPEX	Capital Expenditure
CAPM	Capital asset pricing model
CCF	Climate Change Fund
CESS	Capital Expenditure Incentive Sharing Scheme
CPI	Consumer Price Index
CRNP	Cost Reflective Network Price
Current regulatory period	Regulatory control period of 1 July 2009 to 30 June 2014
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution network service provider
DRP	Distribution Reliability and Performance
DUOS	Distribution Use of System
EBSS	Efficiency benefit sharing scheme
EGWWS	Electricity, Gas, Water and Waste Services
EWON	Energy & Water Ombudsman NSW
F&A	Framework and approach
GFC	Global financial crisis
GWh	Gigawatt Hour
IPART	Independent Pricing and Regulatory Tribunal of NSW
MRIM	Manually read interval meter
MRP	Market Risk Premium
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
NMI	National Metering Identifier
NPV	Net present value
NUOS	Network Use of System
OPEX	Operating Expenditure
Pass through event	Per the Transitional Rules

Endeavour Energy

GLOSSARY

Term	Definition
PTRM	Post tax revenue model
RAB	Regulatory asset base
2015 regulatory control period	The regulatory period 1 July 2015 to 30 June 2019
Regulatory Proposal	Endeavour Energy's proposal for the next regulatory period submitted under clause 6.8 of the Rules
Repex	Replacement expenditure model
RIN	Regulatory Information Notice
RoR	Rate of return
Rules	National Electricity Rules
SAMP	Strategic Asset Management Plan
SCS	Standard Control Services
STPIS	Service Target Performance Incentive Scheme
Transitional Rules	Division 2 of Chapter 11 transitional provisions for NSW/ACT distribution network service providers for the economic regulation of NSW distribution services for the transitional regulatory control period 1 July 2014 to 30 June 2015
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital
X factor	(%) change in real revenues between regulatory years