REGULATORY PROPOSAL

> 1 July 2014 to 30 June 2019

> Submission date: 31 May 2014

CONTENTS

EXECUTIVE SUMMARY

This regulatory proposal outlines how Essential Energy plans to operate and maintain its electricity network in an efficient manner and to keep it safe, reliable and affordable for customers. The regulatory proposal also discusses the funding needed to deliver these objectives.

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. Every five years, electricity distributors must submit regulatory proposals to the AER that explain their proposed capital and operating plans, and the revenue they need to fund those plans.

New South Wales (NSW) and Australian Capital Territory (ACT) electricity distribution businesses are now due to submit their regulatory proposals covering the 2014-19 regulatory control period.

In 2012, the Australian Energy Market Commission (AEMC) consulted the industry 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 regulatory proposals under the new rules. During the consultation period the AEMC decided that a one year transitional regulatory 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 regulatory proposal would cover the period 1 July 2014 to 30 June 2015. It is described as a “placeholder” proposal.

The full regulatory proposal, covering the entire five-year period from 1 July 2014 to 30 June 2019, was to be submitted some months after the transitional regulatory proposal, and would provide detail about forecast capital and operating plans, and revenue requirements.

Essential Energy presented its transitional regulatory proposal on 31 January 2014. The AER made a determination on Essential Energy’s transitional regulatory proposal on 16 April 2014. The document presented here is Essential Energy’s regulatory proposal.

Explaining our role

Essential Energy builds, maintains and operates the electricity distribution network in regional NSW.
We pass our electricity charges on to electricity retailers.

Our distribution charges, combined with TransGrid’s transmission charges, typically represent about half of a customer’s electricity bill. Essential Energy’s average distribution charge is higher than other network areas across Australia. That’s because, relative to the territory our network covers, there are fewer customers in our network. We service 95 per cent of the NSW landmass, but only 24 per cent of NSW customers.

This equates to an average of four customers per kilometre of Essential Energy’s electricity distribution network. On average, customers’ total electricity charges break down into the components shown in Figure E-1.

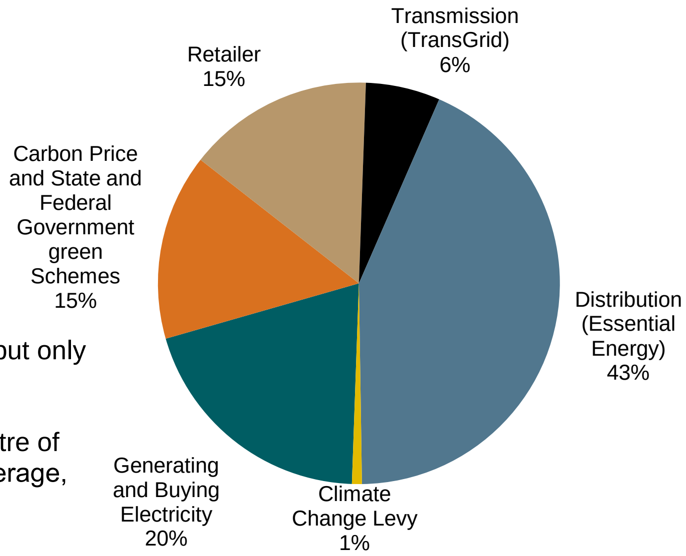

Figure E-1: Components of your electricity bill

NSW Government network reform program

In March 2012 the NSW Government announced a restructure of the three NSW electricity distribution organisations namely Ausgrid, Essential Energy and Endeavour Energy. That 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 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. The network reform program is projected to deliver total business savings of $5.4 billion over the five-year period commencing July 2011.

The benefits of the network reform program are included in this regulatory proposal and will result in lower distribution network charges for customers than otherwise would have been the case in the absence of the network reform program. More detail about the results of the network reform program initiatives in reducing business costs and increasing operational efficiencies can be found in Attachment E.1.

Highlights of our regulatory proposal

Essential Energy is proposing an average network charge reduction of 0.20 per cent below the rate of inflation for a typical residential customer in each year of the 2014-19 regulatory control period. The typical bill impact for residential and small business customers is contained in Table E-1.

Table E-1: Change in average distribution charges for typical residential and small business customers (including metering, % nominal)

Typical annual bill	2014-15	2015-16	2016-17	2017-18	2018-19
Household (7MWh)	2.30%	2.30%	2.30%	2.30%	2.30%
Small business (23MWh)	2.30%	2.30%	2.30%	2.30%	2.30%

Table E-2: Revenue requirement (excluding metering, $ million, nominal)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Annual revenue requirement (smoothed)	1,353	1,352	1,348	1,347	1,357	6,757

This relatively flat forecast revenue requirement for the 2014-19 regulatory control period is driven by significantly lower capital requirements and operational efficiencies pursued by Essential Energy as a result of network reform program initiatives.

Our lower funding need is also a result of lower borrowing costs which were impacted by the Global Financial Crisis in the 2009-14 regulatory control period. As a result, Essential Energy is proposing a weighted average cost of capital of 8.83 per cent be applied to the 2014-19 regulatory control period.

Table E-3: Proposed forecast expenditure[1] ($ million)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Capital expenditure (nominal)	555	537	558	557	564	2,771
Capital expenditure (real $13-14)	542	511	518	505	499	2,574
Operating expenditure (nominal)	475	489	497	516	540	2,516
Operating expenditure (real $13-14)	464	465	461	467	477	2,334

The five year capital program will reduce from $4.2 billion (nominal) approved by the AER for the 2009-14 regulatory control period to a proposed $2.8 billion (nominal) for the 2014-19 regulatory control period – a reduction of 33 per cent, which is 41 per cent below the forecast rate of inflation over the five year period[2].

The five year operating program will increase from $2.3 billion (nominal) approved by the AER for the 2009-14 regulatory control period to a proposed $2.8 billion (nominal) for the 2014-19 regulatory control period – an increase of 25 per cent which is 11 per cent above the forecast rate of inflation over the five year period[3].

We expect, on average, our customers will continue to reduce their use of electricity by an average of 0.4 per cent per annum over the five years commencing 1 July 2014. This expectation is a consequence of the continued take-up of domestic solar panels, the high Australian dollar's impact on Australian manufacturing and the impact of electricity charge increases from July 2009 to July 2012 on customers' energy usage.

We expect that based on the proposed capital and operating program, current network reliability levels will be maintained for the 2014-19 regulatory control period.

Engaging with our customers

Essential Energy has a long history of engaging with customers and stakeholders through a range of channels in order to understand their concerns about network issues. The AER has established a Consumer Engagement Guideline for electricity network operators. The guideline sets out how the regulator expects us to deliver, evaluate and give feedback about our engagement activities.

Therefore, Essential Energy has formalised its approach to customer and stakeholder engagement though the development of our Stakeholder Engagement Framework (Attachment E.2). This is a best practice approach to working with our customers and other stakeholders and engaging in a two-way conversation to understand their issues and concerns with regards to the efficient operation of the distribution network.

More information about the Stakeholder Engagement Framework, research and engagement findings can be found in Chapter 2. To ensure transparency, Essential Energy has also provided a dedicated area online for the storage of relevant regulatory documents and research results. This can be found at essentialenergy.com.au/ourplans.

[1] Capital expenditure includes equity raising costs and operating expenditure includes debt raising costs and the demand management innovation allowance

[2] For comparative purposes, 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

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ABOUT THIS REGULATORY PROPOSAL

This document is Essential Energy’s regulatory proposal for the period 1 July 2014 to 30 June 2019. It sets out the revenue required to manage the network in a safe, reliable and efficient manner for our customers.

It should be read in conjunction with Essential Energy’s transitional regulatory proposal, which covers a single year from July 2014 to June 2015 and the AER’s 16 April 2014 decision on the transitional regulatory proposal. In addition, the attached Customer Overview Paper (Attachment A.1) provides a clear summary of this proposal in a plain English format. This document aims to be accessible to customers and other stakeholders who may not be used to the complex area of electricity regulation and compliance.

Our approach is consistent with the requirements 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 more opportunities to communicate with us, we hope that we can learn more about their views and continue to align our operations to their long-term interests.

Regulatory proposal layout

This regulatory proposal contains the following Chapters:

- Executive summary
- About this regulatory proposal
- Chapter 1 – About Essential Energy
- Chapter 2 – Our Customers
- Chapter 3 – Framework and approach
- Chapter 4 – Building block proposal
- Chapter 5 – Forecast capital expenditure
- Chapter 6 – Forecast operating expenditure
- Chapter 7 – Allowed rate of return
- Chapter 8 – Alternative control services
- Chapter 9 – Pricing arrangements

Regulatory proposal information

We have also included a range of supporting information that provides substantiation of our regulatory proposal, and addresses the compliance obligations within the regulatory proposal. This incorporates the following:

- This regulatory proposal;
- A customer overview of this document in plain English;
- All supporting Attachments submitted to substantiate our regulatory proposal, organised by Chapter and/or section of our regulatory proposal;
- Our response to the Regulatory Information Notice (RIN) issued by the AER on 7 March 2014[4];
- Additional information related to the expenditure forecast assessment guideline that have not been presented in our suite of supporting documents or the RIN;
- Completion of the AER’s pro-forma confidentiality template, as required under its Guidelines; and
- A suite of detailed and largely technical supporting documents.

In addition, Appendix A contains a compliance checklist which demonstrates how we have met all information requirements in the NER.

[4] With subsequent amendments from the AER on 21 March 2014

Feedback on this regulatory proposal

Essential Energy's customer and stakeholders can provide feedback on this regulatory proposal and its supporting documents through the channels shown below:

Channel	Details
Email	ourplans@essentialenergy.com.au
Post	Chief Operating Officer Essential Energy PO Box 5730 Port Macquarie NSW 2444
Phone	13 20 80
Online	essentialenergy.com.au/contactus

Customers can also provide feedback and comments on Essential Energy's regulatory proposal on the AER's website at aer.gov.au.

Essential Energy, Endeavour Energy and Ausgrid jointly manage a Facebook page called Your Power Your Say. We invite you to use it to share your views about our performance as network operators or feedback on this regulatory proposal.
Facebook.com/yourpoweryoursay

1. ABOUT ESSENTIAL ENERGY

Our network

Essential Energy is responsible for building, operating and maintaining Australia's largest electricity network. Our distribution network serves approximately 815,000 customers. Geographically, our footprint covers 95 per cent of NSW, (as shown in Figure 1-1 below), from humid coastal environments in the north coast region, through semi-arid desert in the far west, alpine peaks in the south and a grain belt that crosses central NSW from north to south.

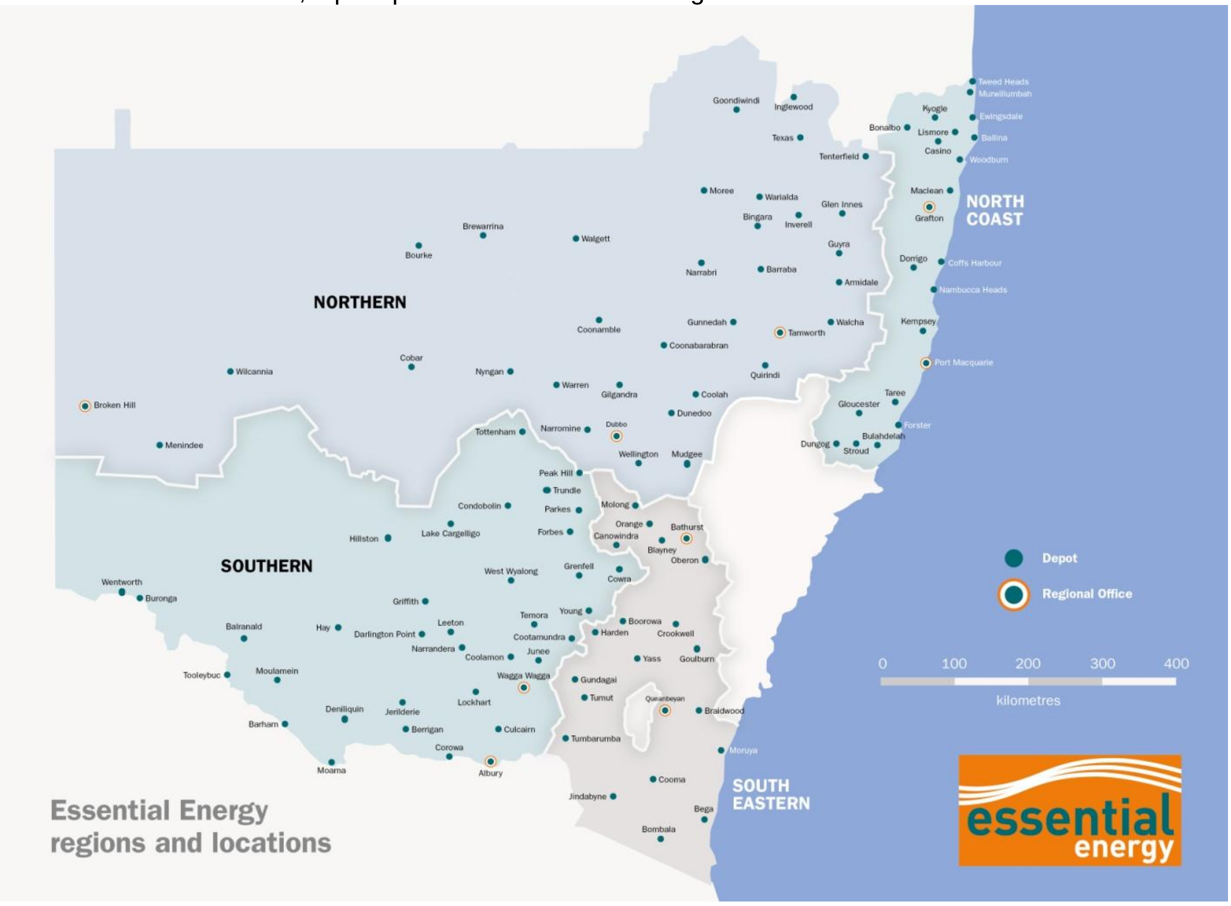

Figure 1-1: Essential Energy's Distribution Network

A vast network spread across a range of environments presents unique and ongoing challenges. Essential Energy's core focus is on ensuring the safe, affordable and reliable delivery of essential services to homes and businesses across rural and regional NSW. We are committed to delivering better value for our customers by reducing our costs without compromising safety or services.

Essential Energy's infrastructure includes approximately:

> 200,000 kilometres of powerlines and cables
> 1.4 million power poles
> 150,000 streetlights
> 135,000 substations
> 400 zone substations.

How our network transports electricity

It is important that customers and other stakeholders understand the electricity supply chain. We believe this will help them provide informed feedback on Essential Energy's plans and priorities. The NSW electricity supply sector involves generation, transmission, distribution and, finally, the retailers who send customers their final bill. Figure 1-2 outlines the electricity supply chain and highlights the physical assets that make up our distribution network.

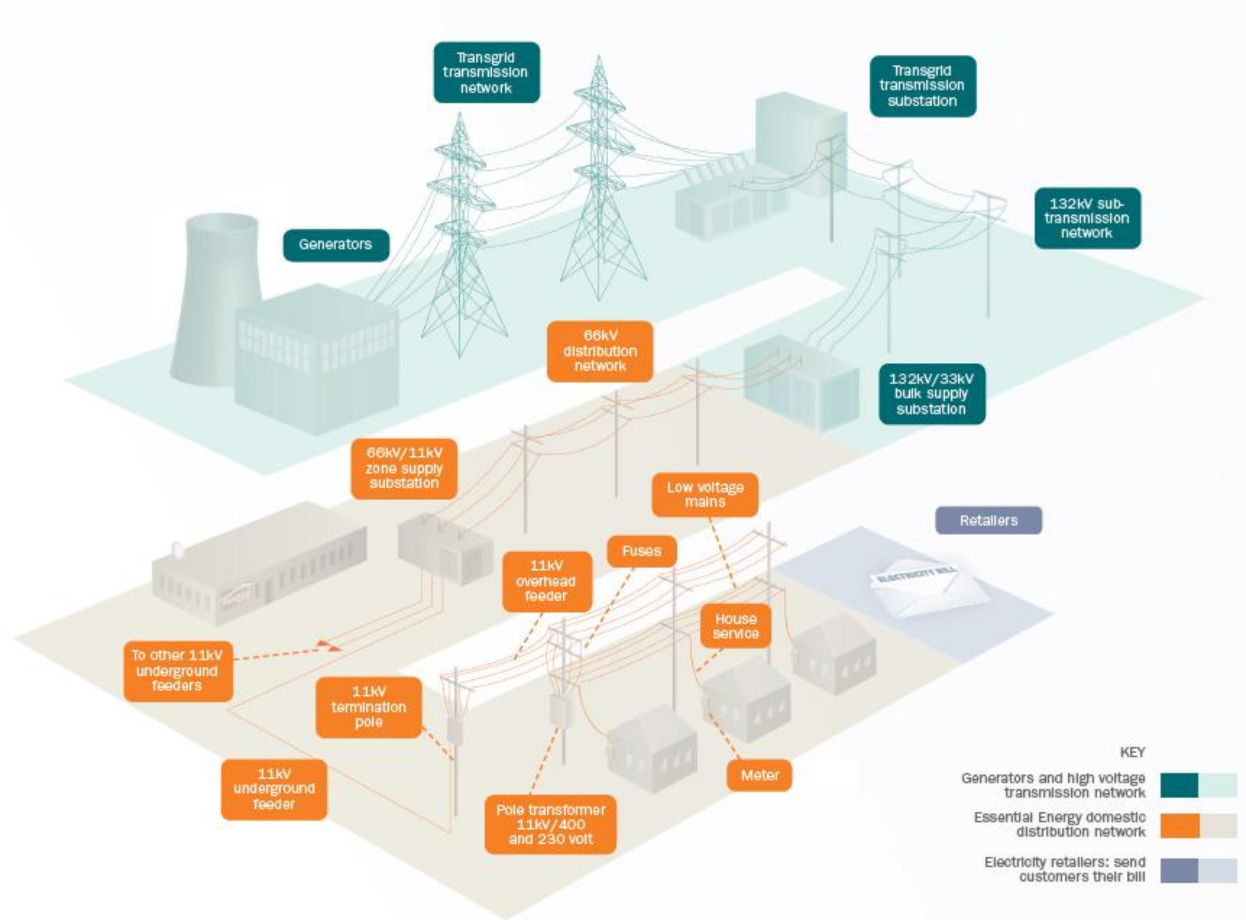

Figure 1-2: Electricity supply chain

Our vision

Our vision is to be of service to our communities by efficiently distributing electricity to our customers in a way that is safe, reliable and affordable. Our objectives include:

> **Safety:** continuous improvement in safety performance for employees, contractors and the community
> **Reliability:** ensuring the reliability, security and the sustainability of Essential Energy's electricity network
> **Affordability:** striving to contain average increases in our share of customers' electricity bills to at or below Consumer Price Index (CPI).

Improving our safety performance for employees, contractors and the public will continue to be our top priority. Safety is measured through a range of indicators to help us strive for improvements across our operations. While safety performance at Essential Energy has been improving, we are planning further policy and operational changes to make the network as safe as possible and to ensure that all our people are free from harm in the workplace and return home in good health.

Network reliability has improved significantly, in line with the licence conditions that applied in the 2009-14 regulatory control period. Compared with 2003, customers today experience approximately 60 minutes less interruption time per year. The frequency of interruptions has also decreased by 26 per cent, to approximately two outages per year. Our asset plan now aims to maximise past investments and focus our future investments so that our network performance can be maintained at those levels. We expect to achieve this while reducing capital expenditure by 42 per cent ($2013-14) from the level allowed by the AER in the 2009-14 regulatory control period.

The variations in charges outlined in this regulatory proposal deliver our third goal of containing average network tariff increases to CPI for our customers. Average network charges were reduced by 2.3 per cent for Essential Energy's residential customers for the 2013-14 financial year. By June 2019 our customers will have benefited from six successive years of changes in network charges at or below the rate of inflation.

Our values

Essential Energy requires employees[5] to understand and support our corporate values. These five values and their associated behaviours are the basis for everything we do.

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 customer 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

5 Employees are defined as permanent employees (full time or part time) and any other person undertaking work for Essential Energy, including contractors and their agents or employees.

2. OUR CUSTOMERS

Our approach to engagement

Essential Energy has a solid history of using traditional and non-traditional channels to engage with customers, communities and other stakeholders. Consistently positive customer satisfaction scores indicate that our business is geared towards a customer-centric operating model that supports the delivery of the network asset management plan.

Engaging with customers and other stakeholders during the formation of Essential Energy's regulatory proposals has helped us understand their concerns. Because we are a state owned corporation, it's particularly important that we align our delivery of a safe, affordable and reliable service with the needs and concerns of customers.

During the preparation of our plans for capital and operating expenditure, we increased the depth and range of stakeholder engagement. To formalise our approach to customer engagement, we have developed a Stakeholder Engagement Framework (Attachment E.2). The framework describes the type of engagement activities customers and stakeholders can expect from the business. It also identifies what we cannot do and why.

The framework aims to meet the following objectives:

- Identify our customers and collate baseline data on demographics and social preferences via segmentation and data analysis.
- Deliver structured research programs to understand the key concerns, and our customers' and stakeholders' priorities for investment.
- Establish and maintain relationships with key stakeholder groups that represent the concerns of customers.
- Identify key gaps in customer education related to the electricity supply chain and programs of work to establish relevant educational tools for customers and stakeholders.
- Provide relevant, effective and two way communication channels that allow customers and stakeholders to provide feedback and receive information in a timely and easy manner.
- Report back to customers and stakeholders regarding outcomes and the reasons for those outcomes.

The engagement activity and research we conducted for our regulatory proposal gave us key insights into the concerns of customers. These insights have helped shape our business objectives to ensure we consistently make decisions that are not only in the best interests of safety, are economically viable, technically feasible and compatible with the environment, but also match our customers' needs.

The framework and our engagement activities will be reviewed and refined on an ongoing basis to ensure a relevant and timely approach to two way communication and education activities. Alongside this, the framework also supports Essential Energy's customer value strategy. This strategy is designed to ensure the business is focused on delivering value to customers through the provision of affordable services, efficient and quality customer service and customer engagement.

Participation spectrum

The spectrum in Table 2-1, as provided in the Stakeholder Engagement Framework, provides an overview of the levels of engagement as well as explaining the goals and delivery mechanisms of each aspect within the spectrum.

Table 2-1: Participation Spectrum

	INFORM	CONSULT	INVOLVE	COLLABORATE	EMPOWER
Definition	Provide the public with balanced and objective information to assist them in understanding the problems, alternatives, opportunities and solutions available.	Obtain feedback from customers and stakeholder groups regarding alternatives and decision making.	Work directly with the public through a process that is designed to ensure concerns and objectives are understood and considered.	Partner with the public throughout the decision making process to develop alternatives and deliver the preferred solution.	Place final decision-making in the hands of the public.
What to expect	We will provide you with information that is relevant and timely around the operational aspects of the network.	We will listen to your feedback and ask structured questions to understand issues and gaps in our planning process.	We will work with you to reflect your concerns and sentiments in our plans as well as how they have influenced the outcomes.	We will work directly with customer and stakeholder groups to understand problems, potential solutions and the risks and benefits of the alternatives to customers with regards to the preferred solution.	Empowering customers in a highly regulated environment such as electricity distribution is not possible for most facets of network management due to the lack of information they have available, the skills and expertise required, and the legislative-requirements around safety and licence conditions.
Who we will engage	All customers and stakeholders.	A representative portion of customers and stakeholders.	• Lobby Groups • Community and Welfare Organisations • Accredited Service Providers • Councils.	Customer Council Rural Advisory Group.	Not applicable.
How we will deliver	We will provide information through social media, on our website and traditional media channels.	We will conduct research programs to gather feedback from a variety of stakeholder groups through a	We will hold forums and workshops as well as meet with stakeholder groups to understand	We will meet with our dedicated advisory groups on a regular basis to listen, understand and act on concerns.	We will operate an electricity distribution network that is safe, reliable and affordable for our customers.

	INFORM	CONSULT	INVOLVE	COLLABORATE	EMPOWER
		number of mediums including social media to enhance feedback options.	concerns to address in our plans.		

Our customers and stakeholders

Essential Energy has approximately 815,000 customers spread across 95 per cent of NSW. In contrast to the other NSW distribution network service providers (DNSPs), Essential Energy has one of Australia's lowest average customer densities of four customers per kilometre of powerline. Understanding the types of customers and stakeholders within the footprint area is important in further targeting activities designed to better understand the needs and concerns of customers. In addition, this understanding is also critical to informing communication and education strategies for business as usual programs.

Customers can also be considered in terms of their connection classification. Recognising this is also important when discussing concerns with customers and stakeholders to ensure relevance and appropriate choice of communication channel.

In broad terms, the following connection classifications apply to Essential Energy's customer base:

- Residential
- Small to medium businesses
- Large low voltage
- High voltage

Residential and small to medium businesses account for the majority of customers. These groups have different network needs than those of large low voltage and high voltage customers. Essential Energy's vast network area spans considerable geographic diversity. It covers regional cities, rural farmland and remote rural locations that are home to customers and stakeholders with varying concerns and requirements. With this in mind, Essential Energy customers can be classified into the following groups:

- Local councils
- Farming groups, councils and associations
- Community welfare organisations
- State Government departments
- Regulators
- Community advisory panels
- Business chambers
- Large energy users
- Retailers
- Accredited service providers
- Community associations

Understanding the concerns of our customers and stakeholders

Understanding the concerns of our customers and stakeholders is the core reason for conducting engagement activities, that then allow the business to act and respond both on a business as usual basis and as part of the regulatory proposal process.

In June 2012, Essential Energy conducted a major research program to explore customer's knowledge, attitudes and behaviours around electricity consumption and investment decisions.

This qualitative research was complemented by a survey with a sample size of over 1000 Essential Energy network customers. Research findings identified six clear customer values. These values are the essence of what is important to our customers and the ways in which they would like Essential Energy to manage these issues as a network distribution business. The full research report is available in Attachment 2.1.

Utilising the values obtained from our research has already informed a number of network programs. Such insights are also useful when making investment and business decisions, because they ensure the concerns of the customer are considered when planning capital and operating expenditure. Figure 2-1 outlines the customer values, what they mean and what we are doing to address them.

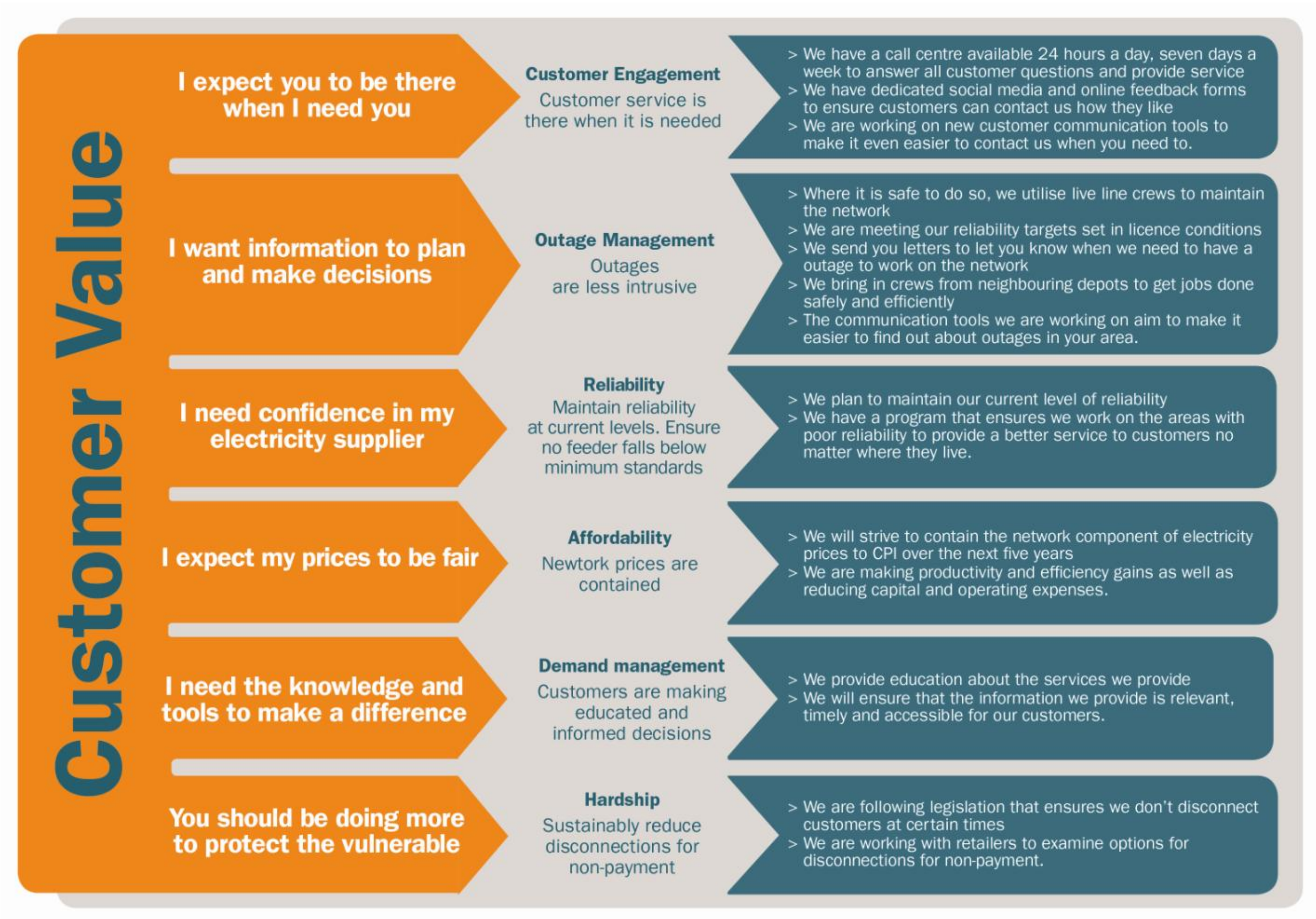

Figure 2-1: Customer values

Customer engagement

Customers want information exchange between themselves and Essential Energy to be simple. This means communicating via channels that make information available when and where they need it. Mobile technology is a growing part of customers' lives, and they want future communications to reflect this.

System Investment Case: Customer Outage Communications Management provides information on proposed programs of work to support this customer value.

Outage management

The provision of clear information about the timing and duration of interruptions makes them more acceptable as it enables better planning. It also gives customers more control over their electricity usage and enables changes in patterns of use.

System Investment Case: Customer Outage Communications Management provides information on proposed communications tools to deliver real-time information.

Reliability

Customers expect a constant supply of electricity, but generally view current levels of reliability as acceptable. For most, a reduction in charges would not compensate for reduced reliability. Power interruptions are an inconvenience for most household customers, but for small businesses and some rural customers interruptions can have financial impacts.

Operational Procedure: Reliability Strategy 2012 - 2019 details our plans for reliability as well as our worst performing feeders program.

Affordability

Customers do not fully understand why charges are rising, but accept it as inevitable and out of their control. However, they expect increases in charges to be a genuine result of investment in infrastructure, rather than an attempt to generate profit. Most customers are trying to reduce their electricity bills, and would like more information to help them do so.

Attachment E.1: Delivering efficiencies for our customers outlines our approach to cost saving and ensuring an affordable network service.

Demand management

Customers place a very high value on being able to control when and how they use electricity. Very few are willing to sacrifice this control, but many are willing to make changes to their appliances and usage patterns in order to manage the affordability of their electricity. A lack of understanding and being overwhelmed with technical information prevents some customers from making informed choices.

See CEOP1121: Demand Management Strategy for proposed demand management programs.

Hardship

Customers see the need to ensure that vulnerable households have access to a reliable electricity supply. However, there is a concern that programs designed to help vulnerable customers may be exploited by those who are not in need.

See the Customer Operations Business Plan for details on the customer value strategy and managing relationships with retailers.

Engagement activities

Essential Energy has a rich history of customer and stakeholder engagement through both formal and informal activities such as safety education programs, social media campaigns, customer communications about what we are doing on the network, as well as asking dedicated customer groups what they think about our plans.

During the preparation of this regulatory proposal, the business increased engagement activities to capture feedback from a broad range of customer and stakeholder groups. Beyond the core research program we also engaged or communicated directly with the following groups/channels:

- Rural Advisory Group
- Customer Council
- Stakeholder forums
- Social media polling and media analysis
- Irrigators NSW
- Cotton Australia
- Local councils

A full list of engagement activities is provided in Attachment 2.2. Specific outcomes and insights are provided within relevant documents to show how our ongoing engagement program supports capital and operating work programs.

Supporting business objectives

The findings from stakeholder engagement activities and research support the objectives of the business in terms of providing a safe, reliable and affordable electricity supply to our customers. Customers and stakeholders made it clear they expect the reliability they currently experience to be maintained, however they are not willing to pay more for this. With this in mind, Essential Energy's regulatory proposal is based on a prudent, safe and efficient approach to network asset management.

Consumer Challenge Panel

The Consumer Challenge Panel (CCP) was established by the AER to assist it in making better regulatory determination's by providing inputs on issues of importance to customers. Essential Energy has had opportunities to meet with the CCP to discuss and provide clarification on our transitional regulatory proposal. This process has provided us with insights into issues of concern to the CCP including:

- remote customer issues – this is addressed in Attachment 2.3
- level of spend in the 2009-14 regulatory control period compared with forecasts for the 2014-19 regulatory control period – this is addressed in Chapters 5 and 6
- significant vegetation management operating expenditure – this is addressed in Chapter 6.

Ongoing customer and stakeholder engagement

Essential Energy's customer and stakeholder engagement activities will continue to be part of our business as usual operations, and will be reviewed to ensure they remain relevant and timely for customers, communities and other stakeholders. The results of our engagement activities will be incorporated into Essential Energy's decision making processes on an ongoing basis as well as informing our customer relationships in future.

Essential Energy's senior management team will present the highlights of this regulatory proposal at a series of stakeholder briefing sessions. These presentations, combined with the ready availability of the Customer Overview Paper (Attachment A.1), will enable timely feedback from a broad range of stakeholders. This feedback will be considered and addressed in our revised regulatory proposal, which is due for submission to the AER in January 2015.

These initiatives will help ensure that customer views are embedded in Essential Energy's long term decision making processes and that our operations continue to be aligned with the long term interests of electricity customers.

The benefits and potential risks to customers

The following summary of benefits and potential risks to customers is in relation to the plans outlined in this regulatory proposal.

Benefits to our customers

- Stable charges - we propose to keep average increases in charges to our share of customers' electricity bills at or below CPI for the next five years.
- A reliable network – we propose to maintain reliability at current levels.
- A safe and sustainable network - our proposal helps ensure the ongoing safety and sustainability of our electricity network and our customers.
- A clearer picture of costs - customers will have a better understanding of the charge they pay for metering services.
- Connections for new growth areas – electricity infrastructure for new growth centres will foster economic development of these areas.
- Removing some cross subsidies - customers who do not use specific services (such as special meter tests or readings) will no longer subsidise those who do.

Potential risks to customers

- Volatility in charges - if energy use is lower than forecast, a revenue cap may result in customers paying more than we propose.
- Reduced reliability - if the AER does not approve our capital program, we may need to postpone projects which may make the electricity supply less reliable in some areas.
- Future charges - if our forecasts for economic growth, asset condition and customer connections are not accurate, we may need to spend more than our AER allowance to address issues we have not identified. This could add to customer charges in the 2019-24 regulatory control period.
- New rules - customers who request a special service such as a meter test may now pay considerably more for that service. The AER requires us to set 'cost reflective' charges so that the user pays the full cost of providing that service. Previously the regulator set charges below the cost of the services, and they were subsidised by the wider customer base.

3. FRAMEWORK AND APPROACH

Context and content of regulatory proposal

In our role as a DNSP, we provide a range of distribution services to our customers. This includes our core network services, connecting new customers, providing metering services, public lighting and other non-routine services such as special meter tests.

As a regulated business, Essential Energy is subject to economic regulation by the AER under the NER. Under this process we are required to submit a regulatory proposal to the AER for what is usually a five year period. The regulatory proposal covers a range of matters including revenue and charges for regulated services.

The 2009-14 regulatory control period ends on 30 June 2014. Due to material changes to the rules in 2012, the AEMC considered that a one year transitional regulatory proposal would address implementation issues from transitioning to the amended rules. The purpose was to establish a placeholder revenue determination to set charges for the regulatory year 1 July 2014 to 30 June 2015. Accordingly on 31 January 2014, Essential Energy submitted its transitional regulatory proposal to the AER for the year 1 July 2014 to 30 June 2015, and the AER released its determination on 16 April 2014.

The rules require Essential Energy to submit a regulatory proposal and the AER to make a further determination in respect of the regulatory control period subsequent to the transitional regulatory year (the regulatory proposal). The subsequent regulatory control period is to be for a term of four years, commencing on 1 July 2015 and ending on 30 June 2019 (the 2015-19 regulatory control period).[6]

However, the rules have been designed in a way that allows the AER to 'look back' in detail at its transitional determination, and make necessary adjustments if required. For this reason, the rule require Essential Energy to treat the transitional regulatory year (2014-15) as if it were the first year of the 2015-19 regulatory control period, and as if this 2015-19 regulatory control period includes the transitional year. Therefore, this regulatory proposal includes all the necessary information to support our proposed expenditures for a five year period, from 1 July 2014 to 30 June 2019 (the 2014-19 regulatory control period).

Essential Energy's regulatory proposal

Essential Energy's regulatory proposal addresses all matters required to be addressed by the rules in relation to a regulatory proposal.[7] Our regulatory proposal comprises this document, Attachments and all supporting documents. It contains our:

> classification proposal, showing how our distribution services should be classified
> building block proposal for standard control services, including indicative charges
> demonstration of the application of the control mechanism for alternative control services, including indicative charges
> proposed connection policy
> proposed procedures for assigning and reassigning customers to tariffs.

[6] Clause S6.1.3(13) requires Essential Energy to specify the commencement and length of the regulatory control period. See also clause 6.3.2(4) of the rules.

[7] See clause 6.8.2(c) of the rules which specifies the elements of a regulatory proposal. Essential Energy's regulatory proposal has been prepared based on Chapter 6 and Division 2 of part ZW of Chapter 11 of version 60 of the NER.

It is also accompanied by:

- an overview paper which explains Essential Energy's regulatory proposal in reasonably plain language and is referred to as the Customer Overview Paper (Attachment A.1)
- information required by the RIN issued by the AER on 7 March 2014[8]
- Checklists which document how Essential Energy has met all the information required by the rules and the RIN.

Clause 6.8.2(c2) of the NER requires Essential Energy's regulatory proposal to be accompanied by information required by the expenditure forecast assessment guideline as set out in the AER's framework and approach paper. The guideline was published by the AER in November 2013 in which the AER stated that:

> *The regulatory information notice (RIN) issued 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 capital expenditure and operating expenditure.*[9]

This approach is confirmed by the AER in its Stage 2 Framework and Approach paper (the stage 2 F&A) in which the AER stated that the guideline was developed to apply broadly to all electricity transmission and distribution businesses. The AER stated some customisation of the data requirements contained in the guideline may be required, and that these customisation issues would be addressed through the RIN that the AER issues to NSW DNSPs for the 2014-19 regulatory control period.[10]

As noted above, the AER issued Essential Energy with a RIN that requires the provision of a suite of information on our forecast capital and operating expenditure. Essential 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 expenditure forecast assessment guideline are addressed by the RIN requirements which have been customised to reflect Essential Energy's business. Accordingly, Essential Energy's RIN response meets the requirements of the expenditure forecast assessment guideline as required by the stage 2 F&A.

Essential Energy has sought to have redacted from publication certain parts of the regulatory proposal on the grounds of confidentiality, predominately encompassing commercially sensitive and security issues. We have completed a confidentiality template in relation to this information as required by the AER's Confidentiality Guideline. This template is submitted together with Essential Energy's regulatory proposal.

Our proposals in response to Stage 1 of the AER's Framework and Approach

In its Stage 1 Framework and Approach paper (the stage 1 F&A), the AER has already made a number of decisions and set out its proposed approach on a number of matters affecting our regulatory determination. Our regulatory proposal sets out where we agree with the AER's decision or approach, or where we propose an alternative.

The key points in this Chapter are:

- our proposal adopts the AER's decisions in the stage 1 and 2 F&A papers. This includes the AER's decisions on classification and control mechanisms, subject to seeking minor clarifications on definitions
- we have suggested minor amendments and clarifications to the way incentive schemes should be applied as part of the building block determination.

[8] With subsequent amendments from the AER on 21 March 2014

[9] AER, *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p25

[10] AER, *Stage 2 Framework and Approach, Ausgrid, Endeavour Energy and Essential Energy, Transitional Regulatory Control Period 1 July 2014 to 30 June 2015 and Subsequent Regulatory Control Period 1 July 2015 to 30 June 2019*, January 2014, p36

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

Proposal on classification of services

Classification of distribution services is important as it determines the extent of regulation that applies to our services. The classification of Essential Energy's distribution services in the 2009-14 regulatory control period was deemed by the rules as part of the AER's final determination.

The stage 1 F&A was the first opportunity for the AER to consider its proposed grouping of Essential Energy's distribution services and how these service groups should be classified for the 2014-19 regulatory control period. The AER proposed to group Essential Energy's distribution services as follows:

> network services
> connection services
> metering services
> ancillary network services
> public lighting services.

For the above service groups, the AER's proposed classification for the 2014-19 regulatory control period is largely the same as that which applied in the 2009-14 regulatory control period except for the following two changes:

> Type 5 and 6[11] metering services and ancillary network services were reclassified from standard control to alternative control services
> Emergency recoverable works will not be classified by the AER from 1 July 2014, meaning this service will not be regulated. They are currently deemed to be standard control services.

The AER's proposed classification of Essential Energy's distribution services is shown in Figure 3-1.

NSW Distribution Services			
Direct control		Negotiated	Unregulated
Standard control	Alternative control		
> Transmission network services > Distribution network services > Augmentations > Metering (Type 7)	> Metering (Type 5 – 6) ○ Compliance driven installation ○ Provision ○ Maintenance ○ Meter reading ○ Data management > Ancillary network services > Public lighting	> Essential Energy does not currently have any services classified as negotiated distribution services.	> Premises-network connections > Network extensions > Metering (Type 1 – 4) > Metering (Type 5 – 6) ○ New and modified installations > Emergency recoverable works

Figure 3-1: Classification of NSW Distribution Services

The NER require that our regulatory proposal shows how the distribution services we provide should, in our opinion, be classified for the next regulatory control period. If our proposed classification differs from the classification suggested in the stage 1 F&A, we are required to identify our reasons for the difference.[12] In relation to this rules requirement, our classification proposal adopts the AER's classification of services decision in the stage 1 F&A.

[11] Type 5 meters record energy use in 30 minutes intervals, while Type 6 meters record accumulated energy use only.
[12] Clauses 6.8.2(c)(1)(i) and (ii) of the NER require Essential Energy to include a classification proposal in its regulatory proposal.

The AER also set out the various components of each of the services above, and further descriptions of each component[13]. While we propose no departure from the AER's decision on the classification of distribution services, we note that there are three areas where we consider the AER's determination could provide more clarity on service descriptions. These are:

> Specification of network augmentations as part of network services - 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 on it from existing users[14], improving security of the network where the consequences of supply loss are high, restoring capacity lost due to de-rating of existing assets, and to address voltage or faults. We request that the AER's draft determination make clear that augmentations may also relate to these issues;
> Seeking clarity from the AER on the classification of emergency recoverable works, particularly in cases where we are not able to identify the parties liable for the damage or are not able to recover from identified parties the costs of repairing the damages; and
> Minor clarifications in relation to the description of certain ancillary network services.

We set out our classification proposal, including our proposed amendments or clarifications on service descriptions in Attachment 3.1.

Further, we agree with the AER that none of the services provided by Essential Energy are suited to being classified as negotiated distribution services. We do not anticipate any negotiated distribution services to arise during the 2014-19 regulatory control period.

Control mechanisms

Control mechanisms provide the basis for how the AER is to regulate standard control and alternative control services. In the stage 1 F&A, 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.
> It would confirm a basis of control for alternative control services in making its determination, that the form of control would be caps on the charges of individual services. The AER also set out its proposed approach to the formulae that give effect to the control[15].

The NER require the AER's decision in its distribution determination on the form of the control mechanisms to be as set out in the relevant framework and approach paper[16]. However, the AER is able to amend the formulae that gives effect to the control mechanisms only if they consider that unforeseen circumstances justify departing from the formulae. We have adopted the AER's decisions on control mechanism as stated in the stage 1 F&A[17]. Further, we have also adopted the formulae that give effect to the control mechanism with a minor clarification to include in the 'B' factor of this formula to include adjustments needed to account for the annual update to the cost of debt. This is further explained in Chapter 9.

Attachment 9.2 sets out Essential Energy's consideration on the control mechanisms for standard control services and alternative control services respectively.

[13] See Appendix D of the stage 1 F&A.
[14] Or combined growth related to existing and new users.
[15] The AER clarified in the stage 2 F& A that it will derive the charges of quoted services from their relevant input costs (e.g. labour rate, materials cost).
[16] See clause 6.12.3(c) of the NER.
[17] Essential Energy's position on control mechanisms is therefore consistent and compliant with the stage 1 F&A. See paragraph 3.2(a) of the RIN issued by the AER on 7 March 2014.

Charging of dual function assets

In the stage 1 F&A, the AER decided that Essential Energy does not own, operate or control dual function assets. The AER's determination in the stage 1 F&A is binding, and therefore there is no opportunity for a DNSP to propose an amendment.

Our proposals in response to Stage 2 of the AER's Framework and Approach

In this section, we set out the decisions the AER made in the stage 2 F&A. The stage 2 F&A was published on 31 January 2014 and set out the AER's proposed approach to the application of incentive schemes, depreciation to be applied when rolling forward the regulatory asset base (RAB), and guidance on the approach for the true-up of alternative control services revenue earned during the transitional year.

Incentives to apply to standard control services

The regulatory framework contains a number of schemes that incentivise businesses to be efficient in their spending, in service standards, and in managing network demand. These are known as incentive schemes and they form part of a building block determination. The AER has published a number of incentive scheme guidelines and is required to set out in its framework and approach paper how it intends to apply these schemes to Essential Energy in the 2014-19 regulatory control period.

The NER require Essential Energy to set out in its building block proposal a description, including relevant explanatory material, of how we propose the incentive schemes that have been specified in the stage 2 F&A should apply in the forthcoming distribution determination[18]. In the sections below we set out our proposals in relation to the application of incentive schemes.

Efficiency benefit sharing scheme

The Efficiency Benefit Sharing Scheme (EBSS) provides a continuous incentive for DNSP's to achieve efficiency gains in operating expenditure. The EBSS that applied to Essential Energy for the 2009-14 regulatory control period was recently revised by the AER (November 2013 version or version 2)[19].

For the transitional year, the AER has decided that the EBSS applicable to the 2009-14 regulatory control period, as modified to align to version 2, will apply to Essential Energy for the transitional year and apply as if the transitional year was the first year of the 2015-19 regulatory control period[20]. For the 2015-19 regulatory control period, the AER specified that version 2 will apply to Essential Energy[21].

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

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

To ensure comparability between the actual outturn operating expenditure and the forecast operating expenditure, and therefore that the efficiency gain or loss are accurately calculated, Essential Energy considers that, in applying version 2 for the transitional regulatory control period and the 2015-19 regulatory control period, actual outturn

[18] See clauses S6.1.3(3),(3A),(4),(5) and (5A) of the NER.

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

[20] AER, *Essential Energy Placeholder Determination for the Transitional Regulatory Control Period 2014-15*, April 2014, p2

[21] AER, *Stage 2 Framework and Approach: Ausgrid, Endeavour Energy and Essential Energy*, January 2014, p20

operating expenditure should also be adjusted for actual outturn actuarial assessments for long service leave obligations. In this way, the performance of the DNSP against the efficient operating expenditure benchmark accepted or substituted by the AER is not distorted.

Capital expenditure sharing scheme and proposed approach to depreciation

The Capital Expenditure Sharing Scheme (CESS) was recently introduced into the regulatory framework as a result of the AEMC's rule changes. The CESS provides rewards or penalties for efficiency gains or losses with respect to capital expenditure. The AER published its capital expenditure incentive guideline in November 2013, detailing the CESS.[22]

In its distribution determination for the transitional year, the AER specified that no CESS applies[23]. This is consistent with the requirements of the NER.[24]

The AER proposes to apply its CESS in the 2015-19 regulatory control period in accordance with its published guidelines. Our proposal is to apply the CESS in the 2015-19 regulatory control period, consistent with the AER's proposed approach to its application to Essential Energy set out in the stage 2 F&A.

We propose that the mechanism for calculating the penalty or reward under the scheme would be calculated in accordance with the AER's guideline. At the end of the 2015-19 regulatory control period, the AER would calculate the cumulative underspend or overspend in net present value terms, using an estimate in the last year of the 2015-19 regulatory control period. The AER would apply a 30 per cent sharing ratio to the cumulative underspend or overspend, but then adjust the final CESS payment to incorporate any financing benefit or cost incurred during the 2015-19 regulatory control period. As required by the AER, further adjustments to the CESS payment may be made to the final CESS payment where there has been a material amount of capital expenditure deferred between regulatory control periods. The CESS payment relating to the underspend or overspend would be added to, or subtracted from, Essential Energy's regulated revenue in the 2019-24 regulatory control period as a separate building block.

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 to actual capital expenditure at the end of a regulatory control period. In establishing the value of the RAB as at the beginning of the regulatory control period following the 2014-19 regulatory control period, the AER can decide to either calculate the depreciation on actual capital expenditure or use the depreciation on forecast capital expenditure. 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 regulatory control period from 1 July 2019 for NSW DNSPs. The AER considers that this approach, in combination with the CESS, will provide sufficient incentive for the distributors to achieve capital expenditure efficiency gains over the 2014-19 regulatory control period.

Our proposal is to apply the AER's approach set out in the stage 2 F&A.

Service Target Performance Incentive Scheme

The AER proposed not to apply its national Service Target Performance Incentive Scheme (STPIS) to NSW DNSPs in the transitional year. It noted that under its approach the current performance reporting obligations will continue to apply, with no revenue at risk[25]. Our proposal is to accept the AER's approach not to apply the STPIS in the transitional year.

22 AER, *Better Regulation, Capital Expenditure Incentive Guideline for Electricity Network Service Providers*, November 2013.
23 AER, *Essential Energy Placeholder Determination for the Transitional Regulatory Control Period 2014-15*, April 2014, p3
24 Clause 11.56.3(a)(3) of the NER.
25 AER, *Essential Energy Placeholder Determination for the Transitional Regulatory Control Period 2014-15*, April 2014, p3

The AER has proposed that the scheme will apply for the 2015-19 regulatory control period, and has identified its proposed arrangements in the stage 2 F&A. Among other things, the AER proposed to set the revenue at risk to be within the range of ±5 per cent. 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.*[26]

With respect to the application of the STPIS, Essential Energy proposes a revenue at risk of ±2.5 per cent. 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[27]. At the time, we noted that applying the maximum revenue at risk of ±5 per cent 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 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. Essential Energy's customer research has shown that the majority of customers are satisfied with their existing level of reliability suggesting a reluctance to pay for further improvements.

Our complete proposal on how the STPIS will apply is set out in Attachment 3.2. 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 per cent. 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 per cent.

Demand Management Incentive Scheme

The Demand Management Incentive Scheme (DMIS) that applied to Essential Energy in the 2009-14 regulatory control period comprised two components:

- a Demand Management Innovation Allowance (DMIA) which consists of parts A and B; and
- a D-Factor component.

From the transitional year onwards, the AER propose to continue applying Part A of the DMIA at the same rate as currently applied to NSW DNSPs, but to discontinue Part B of the scheme as it relates 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 cap form of control.

The AER also propose to discontinue the non-compensatory incentive component of the D-Factor scheme for NSW DNSPs from the transitional year onwards. Our proposal is to apply the AER's approach. However, as the D-factor operates on a two-year lag basis, Essential Energy will be able to recover any associated lagged payments made under the scheme in the 2012-13 and 2013-14 year in the first two years of the 2014-19 regulatory control period[28].

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[26] AER, *Stage 2 Framework and Approach: Ausgrid, Endeavour Energy and Essential Energy*, January 2014, p16

[27] NSW Distributors, *Response to AER Preliminary F&A*, August 2012, p65

[28] AER, *Stage 1 Framework and Approach paper*, March 2013 p32

The AER has noted that the Standing Council on Energy and Resources (SCER) (now known as the Council of Australian Governments Energy Council) 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 intend to develop and implement a new DMIS for the 2015-19 regulatory control period, depending on the progress of the rule change process.

We believe that the AER should apply the incentive scheme if a rule change is implemented in time for our final determination, subject to consultation with Essential Energy. However, for the purposes of the regulatory proposal, we have adopted Part A of the current DMIA by including an amount of $0.6 million per annum in the regulatory proposal, less an adjustment in 2015-16 for any DMIA underspend in the 2009-14 regulatory control period. No lagged D-factor amounts have been included in the regulatory proposal.

Small-scale incentive schemes

Recent changes allow the AER to develop incentive schemes outside those already provided in the NER. These are small-scale pilot or test incentive schemes that allow for regulatory innovation (small scale incentive schemes). Given that the AER has not developed such a scheme, and consequently has not stated a proposed approach for applying one to Essential Energy for the 2014-19 regulatory control period, our proposal is not to implement such a scheme during the course of the 2014-19 regulatory control period.

True-up for alternative control services

The NSW DNSPs requested that the AER specify in the stage 2 F&A how a true-up of charges will be made for alternative control services. This is to account for the fact that alternative control charges were set by escalating the charges of the previous year by CPI. We set out preliminary views on how a true-up mechanism could potentially work as part of our request.

In the stage 2 F&A, the AER noted that, given it was yet to see how Essential Energy intended to treat alternative control services charges in their transitional regulatory proposals, it preferred not to prejudice whether, and if so how, alternative control services charges are to be trued-up. For this reason, it did not specify the exact manner in which alternative control services charges may be adjusted in the stage 2 F&A.

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

4. BUILDING BLOCK PROPOSAL

We propose total unsmoothed annual revenue requirements of $6,824 million ($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.

Essential Energy provides a range of distribution services that are classified by the AER as standard control services. These are services 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 2014-19 regulatory control period.

The key points of this Chapter are:

- Essential Energy is striving to contain average increases in our share of customers' electricity bills at or below CPI over the 2014-19 regulatory control period
- we have sought to minimise our revenue by reducing our costs
- we have smoothed our revenues over the 2014-19 regulatory control period to reduce variations in charges between years. In smoothing our revenues, we have investigated how forecast volumes will impact the charges customers pay over the 2014-19 regulatory control period.

Proposed building blocks

This section provides a summary of our proposed annual revenue requirements based on building block components. The building blocks refer to the efficient costs that we reasonably expect to incur in the 2014-19 regulatory control period. We have used the building block approach prescribed in the NER for the calculation of revenue requirements relating to standard control services.[29] These main elements are inputs into the annual revenue requirement using the AER's Post Tax Revenue Model (PTRM). The completed PTRM is provided at Attachment 4.1[30].

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[31], consistent with the NER requirement. The building blocks relate to the following types of costs:

- **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 including the projected value of the opening RAB as at 1 July 2014 and the remaining lives of assets, and is calculated on a straight line basis. The AER offsets changes in indexation of the RAB through its depreciation calculation and refers to this as regulatory depreciation[32].
- **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 equity respectively to fund current and future investments. The calculation of the return on capital is based on key inputs including the projected value of the opening RAB as at 1 July 2014, the allowed rate of return and forecast capital expenditure.
- **Operating and tax costs** – We receive a revenue allowance to fund our operating activities, and to meet our income tax liabilities.

[29] Our proposed building blocks and annual revenue requirement for each year of the 2014-19 regulatory control period relate to standard control services only. That is, our building block proposal does not include amounts relating to alternative control services or unclassified services.
[30] As required by clause S6.1.3(10) of the NER
[31] We note that whilst this proposal relates to the 2015-19 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 of the NER
[32] See clauses 6.4.3(a)(1) and (3) of the NER

- **Other revenue increments or decrements** – We receive a revenue increase or decrease based on penalties or rewards from incentive schemes that applied in the 2009-14 regulatory control period. The NER 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 unsmoothed annual revenue requirements for the 2014-19 regulatory control period are outlined in Table 4-1.

Table 4-1: Unsmoothed annual revenue requirements ($ million, nominal)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Return on and return of capital						
Return on capital	598	640	678	718	756	3,390
Return of capital	98	116	132	136	130	612
Operating and tax costs						
Operating expenditure[33]	475	488	496	515	539	2,513
Income tax	69	68	81	82	82	383
Other revenue increments or decrements						
EBSS revenue	(15)	(53)	(48)	39	0	(77)
DMIS revenue[34]	1	0	1	1	1	3
Shared asset revenue	0	0	0	0	0	0
Annual revenue requirement (unsmoothed)	1,226	1,260	1,340	1,490	1,508	6,824

Note: Totals may not add due to rounding

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 2014-19 regulatory control 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. This is discussed in detail in Chapter 7.

We receive a return of capital (or regulatory depreciation) based on the age profile of the assets within the RAB and the method of calculating depreciation. The key inputs used in developing our estimate of the return on and return of capital are set out below.

Opening value of the regulatory asset base

The estimate of the value of our RAB (for standard control services) as at 1 July 2014 is $6,770 million as shown in Table 4-2. We have calculated these amounts based on clause 6.5.1 and schedule 6.2 of the NER using the AER's roll forward model (RFM). The RFM is provided at Attachment 4.2.

The RAB value reflects the roll forward of actual capital expenditure for the years 2008-09 to 2012-13, and estimated capital expenditure for the 2013-14 year. These capital expenditure amounts contain the actual and estimated capital expenditure relating to Type 5 and 6 metering services and ancillary network services.[35]

However, as the AER has changed the classification of some services currently deemed to be standard control services in the 2009-14 regulatory control period to alternative control services from 1 July 2014, adjustments to the value of the RAB as at 1 July 2014 are necessary to exclude the value of assets used to provide services that

[33] Inclusive of debt raising costs for all years
[34] Inclusive of a DMIA adjustment of $0.4 million in 2015-16
[35] These services are classified as standard control services prior to 1 July 2014

are no longer classified as standard control services. This is to ensure accurate calculation of the annual revenue requirements for standard control services.

We have excluded an amount of $118 million from the RAB as at 1 July 2014, in order to reflect the value of existing assets used to provide Type 5 and 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. Chapter 8 and Attachments 8.4 and 8.5 provide details of the method we used to calculate the values of Type 5 and 6 metering services assets to be removed from the RAB. Table 4-2 shows the roll forward of Essential Energy's RAB from 1 July 2009 to 30 June 2014.

Table 4-2: Opening RAB value for standard control services as at 1 July 2014 ($ million, nominal)

	2009-10	2010-11	2011-12	2012-13	2013-14
Opening RAB	4,319	4,821	5,384	6,066	6,518
Add: Actual and estimated capital expenditure	688	724	771	655	585
Less: Regulatory depreciation	187	160	89	202	171
Less: Adjustment to reflect actual vs. allowed capital expenditure in 2008-09					45
Less: Indicative metering services assets to be removed					118
Closing RAB	4,821	5,384	6,066	6,518	6,770

Note: Numbers may not add due to rounding

Forecast capital expenditure

Table 4-3 shows the forecast capital expenditure relating to the provision of standard control services. Details of our expenditure plans are provided in Chapter 5.

Table 4-3: Forecast capital expenditure relating to the provision of standard control services[36] ($ million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Capital expenditure	542	511	518	505	499	2,574

Note: Numbers may not add due to rounding

Allowed rate of return

We propose a conservative estimate of the rate of return of 8.83 per cent using a trailing average approach to the cost of debt (using a ten year trailing average commencing January 2004), and a long term average approach to the cost of equity informed by a range of relevant available evidence on the efficient cost of equity for energy networks.[37]

We propose a cost of debt of 7.98 per cent and a cost of equity of 10.11 per cent. Table 4-4 shows the proposed rate of return we used to calculate the return on capital building block component shown in Table 4-1. Chapter 7 of this proposal, along with corresponding Attachments and supporting documents, provide further information on the proposed rate of return.

[36] Includes equity raising costs

[37] 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.

Table 4-4: Proposed rate of return

Rate of return parameters	Proposed %	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 credits	25%	25%

Regulatory depreciation

Regulatory depreciation is the depreciation on the value of the RAB offset by the indexation on the RAB. The regulatory depreciation amount for each year of the 2014-19 regulatory control period is shown in Table 4-1.

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 respective remaining asset lives, and new assets added during the 2014-19 regulatory control period by their standard asset lives.

Essential Energy has adopted the AER's preferred approach to the calculation of remaining asset lives as at 1 July 2014, as set out in the RFM at Attachment 4.2. This approach calculates the remaining lives as at 1 July 2014 by weighting the remaining lives of assets existing at 1 July 2009 and the remaining lives of assets added to the RAB during the 2009-14 regulatory control period. The weighting used is the depreciated regulatory value of assets as at 30 June 2014.

While we have adopted this approach, it is important to note that it over estimates and extends the remaining asset lives for each class of assets as more weighting is given to the new assets added during the 2009-14 regulatory control period. 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, Essential Energy has a weighted average remaining life of 33.3 years according to the AER's approach, but an actual weighted average remaining life for accounting purposes of 21.9 years.

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

Within the AER's PTRM, depreciation is calculated as straight line depreciation less the indexation of the RAB for inflation[38]. We have used a forecast inflation rate of 2.50 per cent as a placeholder for the regulatory 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 Reserve Bank of Australia's (RBA) forecast of inflation for the first two years and the mid-point of the RBA's target range for inflation (2.5o per cent) for another eight years to provide a ten 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 Essential Energy 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 Essential Energy's depreciation expenses. It will be a difficult task to find a solution but we will be conducting further analysis on this issue and will provide any findings to the AER at the earliest of when they become available or as part of our revised regulatory proposal in January 2015.

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

Our nominated depreciation schedules and relevant details required by the NER can be found in the PTRM at Attachment 4.1.

Operating and tax costs

Forecast operating expenditure

Table 4-5 shows the forecast operating expenditure relating to the provision of standard control services. Details of our operating expenditure plans are provided in Chapter 6 of the regulatory proposal.

Table 4-5: Forecast operating expenditure relating to the provision of standard control services[39] ($ million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Operating expenditure	464	465	461	467	477	2,334

Note: Totals may not add due to rounding

Estimated cost of corporate tax

The estimates of the cost of corporate tax for each year of the 2014-19 regulatory control period are shown in Table 4-1, and have been calculated using the PTRM which can found at Attachment 4.1.

To estimate the cost of corporate tax we have used the current corporate tax rate of 30 per cent and 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 per cent[40] and the latest estimate of the market value of distributed imputation credits from consultant Strategic Finance Group (SFG)[41] of 0.35[42]. The proposed imputation credit of 0.25 is further discussed in Chapter 7.

Other proposed revenue adjustments

The NER require that the AER allows Essential Energy to include revenue increments or decrements that relate to the operation of incentives during the 2009-14 regulatory control period. The NER also require a DNSP to reduce its revenue to account for the use of shared assets.

Proposed EBSS revenue increment

Essential Energy has applied the EBSS scheme outlined by the AER in its final determination for the 2009-14 regulatory control period. This provides estimated carryover amounts for the 2014-19 regulatory control period as set out in Table 4-1. We have provided the calculation of the EBSS carryover amounts in Attachment 4.3.

The EBSS was developed and has been designed by the AER to incentivise DNSPs to be efficient, and for customers to share in the efficiency gains and losses made by DNSPs. We note that we have calculated the EBSS revenue adjustment consistent with the scheme that was applied to us for the 2009-14 regulatory control period[43].

Proposed DMIS revenue increment

The AER applied the DMIS to Essential Energy in the 2009-14 regulatory control period. The DMIS provides incentives for DNSPs to manage demand on their networks and is made up of two components:

- the D-factor scheme implemented by IPART for the 2004-09 regulatory control period. This D-factor scheme was adopted by the AER to apply to Essential Energy in the 2009-14 regulatory control period
- a DMIA which provides for the pursuit of innovative broad based demand management.

[39] Includes debt raising costs and DMIA

[40] NERA, *The payout ratio,* June 2013, page 13.

[41] SFG was engaged by the Energy Networks Association (ENA), of which Essential Energy is a member, to advise on the AER rate of return guideline consultation process.

[42] SFG, *Updated dividend drop-off estimate of theta*, June 2013, p31

[43] AER, *Final decision – New South Wales Distribution Determination 2009-10 to 2013-14*, p.245

The rules permit the recovery of revenue increments (or return of revenue decrements) in the 2014-19 regulatory control period relating to incentive schemes that apply in the 2009-14 regulatory control period[44].

The D-factor scheme developed by IPART provided incentives for DNSPs to undertake projects to manage demand on their networks, thereby reducing the need for expenditure. The D-factor that applied as part of the DMIS for the 2009-14 regulatory control period was subject to a lag of two years between performance in a regulatory year and incorporation of the incentive payment in charges. As such, any revenue increment related to our performance under the D-factor for 2012-13 and 2013-14 is not included in the revenue we have collected from customers in the 2009-14 regulatory control period. Accordingly, Essential Energy is able to include in its revenues for the first two years of the 2014-19 regulatory control period any actual and expected incentive payments relating to 2012-13 and 2013-14 respectively. However, Essential Energy does not expect to have any lagged D-factor payments and therefore has not included any increments in its revenues for 2014-15 and 2015-16.

Essential Energy was also provided with an annual allowance of $0.6 million ($2008-09) in the 2009-14 regulatory control period for DMIA. Any of this cumulative annual allowance that is not spent and approved by the AER will be returned to customers in 2015-16 when the results of all actual DMIA expenditure for the 2009-14 regulatory control period are known[45].

At the time of submitting the regulatory proposal, Essential Energy forecasts an underspend of approximately $0.4 million for the 2009-14 regulatory control period. We have included this forecast revenue decrement in the annual revenue requirement under the DMIA in the 2015-16 year. Refer to Attachment 4.4 for the calculation of this DMIA underspend.

It must be noted that this amount is a placeholder only, as the actual expenditure for 2013-14 is not yet known and therefore the AER's assessment of Essential Energy's DMIA expenditure for the full 2009-14 regulatory control period has not yet been undertaken. We expect this outcome will be known at the time of the AER's final decision for the 2014-19 regulatory control period and any necessary adjustments will be made accordingly.

Proposed shared asset revenue decrement

Shared assets are those that are used to provide both regulated and unregulated services. The AER may reduce Essential Energy's annual revenue requirement for a regulatory year to reflect the costs of using shared assets that are being recovered from unregulated revenues. 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 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 one per cent of its total smoothed revenue requirement for a particular regulatory year.[46] If this material threshold is not met, no shared asset cost reduction applies.[47]

We have applied the AER's shared asset guideline 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 regulatory control period is shown in Table 4-6.

[44] Clause 6.4.36(a)(5) of the NER

[45] AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme*, November 2008, page 3.

[46] AER, *Better Regulation, Shared Asset Guideline*, November 2013, p8

[47] AER, *Better Regulation, Shared Asset Guideline*, November 2013, p6

Table 4-6: Materiality of shared asset use ($ million, nominal)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Forecast unregulated revenue from shared asset	1	2	2	2	2	9
Smoothed revenue (prior to shared asset reduction)	1,353	1,352	1,348	1,347	1,357	6,757
Materiality percentage	0.10%	0.11%	0.13%	0.15%	0.17%	0.13%

Consequently, no shared asset cost reduction to the proposed annual revenue requirement for any regulatory year of the 2014-19 regulatory control period is necessary.

Proposed revenue requirements

Annual revenue requirements

In the previous section we set out our proposed building blocks. The addition of the building blocks is used to derive Essential Energy's total proposed annual revenue requirement (ARR), as set out in Table 4-7 below.

Table 4-7: Proposed annual revenue requirement ($ million, nominal)

	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Actual/estimated revenue	1,509	1,367						
Proposed ARR (unsmoothed)			1,226	1,260	1,340	1,490	1,508	6,824

Note: Numbers may not add due to rounding

This revenue will be 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 that network and comply with our regulatory obligations. They also provide a reasonable return on our investment in the network.

As explained in Chapter 3, the AER has made a placeholder determination on Essential Energy's ARR for 2014-15. The rules require the AER essentially to re-make this decision in its final determination on this regulatory proposal[48] and to account for differences in the amounts it approved under the transitional determination and the determination on this regulatory proposal, in the ARR of the 2015-19 regulatory control period. We address this 'true-up' of the ARR for the transitional year below.

Adjustment to total revenue requirement for the transitional year

Essential Energy's total revenue requirement for the 2014-19 regulatory control period must be fully adjusted for the difference in the ARR approved for the transitional determination, and the ARR determined revenue for 2014-15 as part of the AER's final determination for the 2014-19 regulatory control period, provided that the adjustment is neutral in net present value terms[49].

In our transitional regulatory proposal we outlined the amount we proposed for the ARR for standard control services for the transitional year and the inputs used in this calculation. This was separate to the bundled revenue we had proposed in addition to the ARR for services that had been reclassified from standard control services.[50]

48 Clauses 11.56.4(b) & (c) of the NER.

49 Clause 11.56.4(h) of the NER

50 In accordance with the approach preferred by the AER in relation to the setting of indicative charges for the transitional year, we had also aggregated the costs of providing standard control services, certain alternative control services such as metering services (but not public lighting) and unclassified services to calculate a total bundled revenue for the purpose of setting DUOS charges for the transitional year. We nominated the 'bundled revenue' to be the amount that will be recovered via DUOS charges for the 2014-15 year.

For this proposal, we have only proposed building block elements and ARR that are for the provision of standard control services. That is, any amounts in relation to alternative control or unclassified services have been excluded from our building block proposal and proposed ARR for each year of the 2014-19 regulatory control period.

As noted in our transitional regulatory proposal, whilst the AER's approach to setting charges for alternative control services for 2014-15 was via general network charges[51], we consider that the demarcation between standard control services and alternative control services is essential to the AER's decision in relation to calculating the under or over recovery of standard control services revenue for the transitional year (as per clauses 11.56.4(h)-(j) of the rules). In Appendix 1 of our transitional regulatory proposal, we noted that the bundled revenue should not be used in adjusting the ARR for standard control services in the 2015-19 regulatory control period.

Accordingly, we understand the AER's transitional determination of the ARR for Essential Energy is $1,221 million (nominal). This is the smoothed revenue that relates to standard control services only (as per the AER's classification of services in the stage 1 F&A)[52]. Consequently, when making the adjustment as required under clauses 11.56.4(h)-(j) of the rules, the AER needs to use the $1,221 million smoothed revenue it determined for the transitional year in its transitional determination, and the amount it will determine for the transitional year in its final determination on this regulatory proposal (that is, its decision on the $1,353 million ARR we have proposed for 2014-15 in Table 4.8).

The recovery of revenue needed to cover the costs of providing reclassified alternative control services in distribution use of system (DUOS) charges was for the transitional year only. Separate alternative control charges will be established for the 2015-19 regulatory control period. Furthermore, we consider adjustments to alternative control services charges in the 2015-19 regulatory control period should be made to account for the under or over recovery of alternative control services revenue earned in the transitional year. This is discussed further in Chapter 8.

Proposed smoothed revenue and X-factors

To minimise variations in charges over time we need to take into account fluctuations in the ARR over the course of the 2014-19 regulatory control period.

As discussed in the sections below, in deciding on the proposed smoothed revenues and the resulting X-factors we have considered:

- the desire of our customers' for stable charges over the 2014-19 regulatory control period
- the complexities that arise from the inclusion of the transitional year
- forecast changes in energy consumption over time
- though not a formal requirement, the NER requirement[53] to minimise differences between ARR and smoothed revenue in the last year of the 2014-19 regulatory control period.

The smoothed revenue profile in Table 4-8 has been calculated using the AER's PTRM and ensures that our proposed smoothed revenues are equal to required revenues in net present value terms. The PTRM is provided at Attachment 4.1.

Table 4-8: Proposed smoothed annual revenue requirements ($ million, nominal)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Smoothed annual revenue requirement	1,353	1,352	1,348	1,347	1,357	6,757

Note: Numbers may not add due to rounding

[51] By bundling standard control services and alternative control services revenues

[52] This amount is calculated as the difference between the total smoothed revenue of $1,292 million and the metering, ancillary network services and emergency recoverable works revenue of $71 million. These revenues have been excluded as they are classified as alternative control services. See AER, *Ausgrid, Endeavour Energy, Essential Energy, ActewAGL, Transitional Distribution Decision, April 2014*, tables 4.4 and 4.5, pp 23-24

[53] That would otherwise apply but for rules introduced as part of the AEMC's 2012 rule changes. See clause 11.56.4(c) of the NER

As discussed further in Chapter 7, we propose a cost of debt that will be updated annually during the 2014-19 regulatory control period. This means that for each year of the 2014-19 regulatory control period, the allowed rate of return will be different depending on the update to the annual cost of debt. As further explained in Chapter 7 and associated Attachments and supporting documents, we propose to account for the revenue adjustment needed to reflect the updated annual cost of debt through the control mechanism formula.

As demonstrated in Figure 4-1, we have smoothed revenues so that they do not fluctuate greatly between regulatory years.

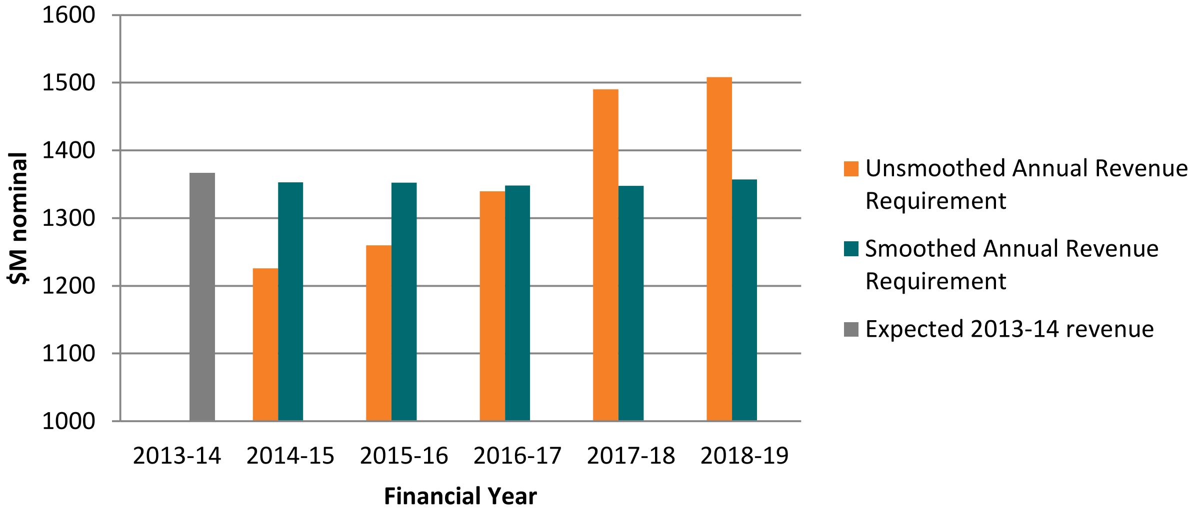

Figure 4-1: Proposed smoothed annual revenue requirement vs. unsmoothed annual revenue requirement

The X-factors represent the real percentage change in the smoothed revenue for each year of the 2014-19 regulatory control period and are shown in Table 4-9. The X-factor is important in ensuring that we comply with the control mechanism.

Table 4-9: Proposed X-factors (%, real)

	2014-15	2015-16	2016-17	2017-18	2018-19
X-factors	3.44%	2.47%	2.74%	2.48%	1.76%

Our proposed smoothed revenue and resultant X-factors have been influenced by energy consumption forecasts.

Energy consumption

Changes in energy consumption impact the charges customers pay for electricity. For example, if the required level of revenue drops in one year, but then rises again in subsequent years[54], and we do not attempt to smooth revenue recovery over the 2014-19 regulatory control period, customers could face a movement downwards in charges followed by a movement upwards.[55] Similarly, if energy consumption falls and required revenue remains at the same level, then average charges would need to increase.

Figure 4-2 depicts actual energy consumption against the AER approved energy consumption forecasts for each year of the 2009-14 regulatory control period. It also shows energy forecasts for each year of the 2014-2019 regulatory control period. This forecast is based on information available as at the end of November 2013 and has been used to calculate indicative charges for each year of the 2014-19 regulatory control period.

[54] Rise and fall in revenue may reflect the lumpiness of the expenditure profile
[55] Assuming energy consumption remains constant.

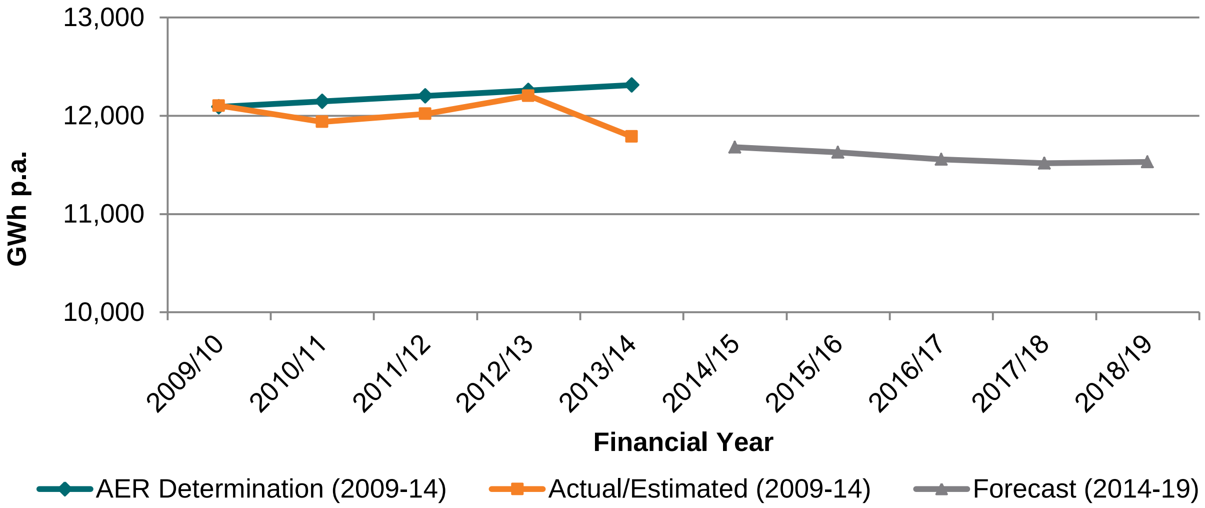

Figure 4-2: Energy Volumes 2009-10 to 2018-19

The National Institute of Economic and Industry Research (NIEIR) forecasts that on average, our customers will continue to reduce their use of electricity by 0.4 per cent per annum over the five years commencing 1 July 2014 in Essential Energy's network. The forecast reduction in consumption is a consequence of the continuing take-up of domestic solar photo voltaic technology, the wind-up of the NSW Solar Bonus Scheme, the impact of the high Australian dollar on Australian manufacturing, the uptake of energy efficient appliances, improved building standards, and the continuing impact of double-digit electricity charge increases from July 2009 to July 2012. The NIEIR report can be found at Attachment 4.5.

Indicative charges and bill impact

Essential Energy is striving to contain average increases in our share of customers' electricity bills at or below CPI over the 2014-19 regulatory control period. We have examined our strategies, processes and procedures to identify scope for savings. This reflects our commitment to alleviate pressure on charges for customers, and our ongoing effort to be effective and efficient in everything we do, without compromising on 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 charges for each year of the 2014-19 regulatory control period.

Movement in average distribution charges

A useful indication of how average charges could move over the 2014-19 regulatory control period is demonstrated in Table 4-10.

Table 4-10: Change in average distribution charges based on latest energy forecasts (% change in real charges)

	2014-15	2015-16	2016-17	2017-18	2018-19
Average change in distribution charges (real)	-1.76%	-1.76%	-1.76%	-1.76%	-1.76%

This average change in charges is based on our latest forecast of energy consumption for the 2014-19 regulatory control period. However, energy consumption is difficult to forecast and in recent years has not followed expectations. While every effort has been made to forecast accurately for the 2014-19 regulatory control period:

- if energy consumption falls below our forecast, average charges will need to increase above the level shown in Table 4-10
- if energy consumption rises above our forecast, average charges would decline below the level shown in Table 4-10

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 2014-19 regulatory control period. This may change based on energy consumption and charging decisions each year.

Indicative charges

Under Clause 6.8.2(c)(4) of the NER we are required to provide indicative charges for direct control services for each year of the 2014-19 regulatory control period. Table 4-11 shows the indicative DUOS charges that recover the ARR associated with standard control services.

Table 4-11: Indicative DUOS charges for published tariffs[56] for 1 July 2013 to 30 June 2019 (average c/KWh, nominal)[57]

Tariff classes	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	Average % change p.a.
Low Voltage	14.85	14.96	15.07	15.18	15.30	15.41	0.74%
High Voltage	7.49	7.55	7.60	7.66	7.71	7.77	0.74%
Sub-transmission	2.84	2.86	2.88	2.91	2.93	2.95	0.74%
Unmetered	8.94	9.01	9.07	9.14	9.21	9.28	0.74%

While these charges provide an early indication of our commitment to customers for the 2014-19 regulatory control period, they are indicative only at this stage. They are based on Essential Energy's proposed annual revenue requirements for the 2014-19 regulatory control period, and do not reflect the placeholder revenue determined by the AER for the 2014-15 year which will be subject to a true-up in the AER's final determination for the 2014-19 regulatory control period. The actual charges that customers will receive in each year of the 2014-19 regulatory control period are dependent on:

- the AER's final distribution determination for Essential Energy for the 2014-19 regulatory control period and any differences between the revenue determined for the 2014-15 year and the placeholder revenue for that year
- updated energy consumption forecasts and actual consumption outcomes over the 2014-19 regulatory control period
- any changes in the relative portion of revenues recovered from each tariff and tariff component.

Essential Energy also notes that the charges outlined above are only a portion of the total network use of system (NUOS) charge to customers. NUOS charges also include the cost of services provided by NSW transmission network service providers (notably TransGrid), as well as the recovery of amounts to satisfy obligations under the NSW Climate Change Fund and Queensland solar rebate. These components are outside of our control.

Pass through events

The pass through mechanism in the NER recognises that a DNSP can be exposed to risk or loss beyond its control, and these risks or losses may have a material impact on its costs. A cost pass through enables a business to seek

[56] These do not include cost reflective network charges which are customer specific tariffs calculated for very large customers.
[57] These prices calculated by reference to the forecast revenue to be recovered from each tariff class and forecast consumption within those classes.

the AER's approval to recover (or pass through) the costs of defined unpredictable, high cost events for which the distribution determination does not provide a regulatory allowance.

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 clause 6.6.1(a)(1) of the NER.

Essential Energy has undertaken a thorough risk assessment of its operations using the bow-tie risk analysis methodology[58]. We have cross-checked the results of this analysis against our historical risk register and engaged Ernst & Young to review our key risks and advise on:

> the appropriateness and prudency of Essential Energy's risk management approach (including insurance arrangements) in light of the key risks that we face
> the appropriate regulatory treatment of each risk based on Essential Energy's current and/or proposed risk management approach.

Based on Ernst & Young's report and our own 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 Essential 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.

We propose the following events be approved as part of our regulatory determination, and they will then 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
> aviation hazards event.

In proposing these events, we have had regard to the considerations in Chapter 10 of the NER and consider that each event meets the necessary requirements to be approved as a nominated cost pass through event. Essential Energy's proposed definitions for these events and detailed assessment of how these events meet the pass through event considerations is provided in Attachment 4.6. Ernst & Young's report is provided at Attachment 4.7.

Essential Energy considers that the pass through provisions of the NER also apply to alternative control services, as all direct control services are subject to the distribution determination. Therefore, any nominated pass through events accepted by the AER should apply to all direct control services, including public lighting services, Type 5 and 6 metering services, and ancillary network services.

[58] 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.

5. CAPITAL EXPENDITURE

Summary

Our proposed capital program of $2.6 billion ($2013-14) will ensure that we continue to comply with our reliability and safety obligations, while striving to contain average increases in our share of customers' electricity bills at or below CPI. Our carefully prioritised program of work will also enable us to maintain the long term sustainability and health of the network.

Our forecast capital expenditure for the 2014-19 regulatory control period is 26 per cent lower than actual capital expenditure we expect to incur during the 2009-14 regulatory control period, as illustrated in Figure 5-1.

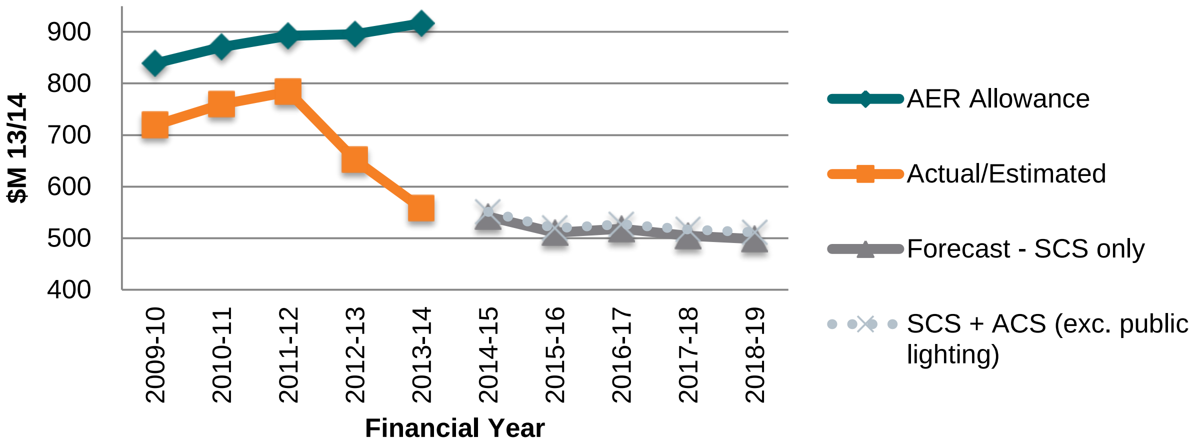

Figure 5-1: Capital expenditure 2009-10 to 2018-19 ($ million, 2013-14)

This lower forecast capital expenditure reflects the achievement of considerable improvements in the security of the network in the 2009-14 regulatory control period under new licence conditions, and a return to a more steady state level of investment in the 2014-19 regulatory control period. The lower proposed amount also reflects the efficiencies achieved under the network reform program, with primary focus on affordability through striving to contain average increases in our share of customers' electricity bills at or below CPI. For a more detailed explanation of the network reform program and the savings delivered across NSW DNSPs please refer to Attachment E.1.

Investment during the 2009-14 regulatory control period was driven by the need to meet licence conditions and refurbish ageing assets. Essential Energy's investment approach for the 2014-2019 regulatory control period will continue to focus on meeting the needs of our customers. Due to actual capital expenditure being below the AER approved allowance in the 2009-14 regulatory control period, the opening RAB at 1 July 2014 is below expectations, with customers sharing the benefits of this underspend through lower charges in the 2014-19 regulatory control period.

In this Chapter, we demonstrate our achievements in the 2009-14 regulatory control period including reasons for variations to allowances. We then set out the underlying drivers and network strategy for the 2014-19 regulatory control period. We provide a brief summary of our forecasting method, and describe each of our investment plans and resulting capital expenditure forecasts for the 2014-19 regulatory control period. Finally, we refer to evidence which the AER can use to assess how we have met the capital expenditure objectives, criteria and factors in the NER.

Focus of the 2009-14 regulatory control period

Capital expenditure in the 2009-14 regulatory control period was largely focussed on improving network security and reliability as reflected in the NSW Design, Reliability and Planning Licence Conditions (the licence conditions). Having achieved substantial progress towards compliance, these issues will no longer be a focus for the 2014-19 regulatory control period.

The projects that we undertake on the network at any given point in time are a direct outcome of the issues and challenges facing the business at that time and in the future. Our network strategy at the commencement of the 2009-14 regulatory control 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 licence conditions
> ensuring that our 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.

Outcomes from the 2009-14 regulatory control period

The 2009-14 regulatory control period saw us embark on the largest investment program in our history, driven largely by the need to meet these challenges. 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 utilising our full expenditure allowance. This underspend will be passed through to customers in the 2014-19 regulatory control period in the form of lower network charges. Detailed information on the actual spend versus regulatory allowance for the 2009-14 regulatory control period can be found in Attachment 5.1.

Table 5-1 sets out our actual and forecast capital expenditure from 1 July 2004 to 30 June 2019[59].

	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Growth	80	107	212	227	236	280	253	279	254	212	189	159	140	135	129
Refurbishment	65	87	115	123	111	170	233	226	197	186	217	233	255	253	257
Reliability	64	107	75	98	140	111	128	127	128	67	31	33	33	34	34
Compliance	21	27	13	7	10	13	19	20	8	9	27	36	39	39	40
Non System	112	105	117	121	149	145	127	132	65	85	77	51	52	44	38
Total capex	342	434	532	576	646	719	759	784	652	558	542	511	518	505	499

Table 5-1: Capital expenditure 2004-05 to 2018-19[60] ($million, 2013-14)

Table 5-1 confirms a return to to a more steady state level of investment, so much so that forecast capital expenditure in the last four years of the 2014-19 regulatory control period will fall below a level that was last experienced in 2006-07. Table 5-1 clearly illustrates the shift in focus from growth and reliability capital expenditure in the 2004-09 and 2009-14 regulatory control periods to refurbishment and replacement capital expenditure in the 2014-19 regulatory control period.

Licence conditions

The requirements of the licence conditions set out the design planning criteria to be used by Essential Energy in planning, developing, managing and operating its electricity network to ensure that it provided an adequate supply with an appropriate level of security. In particular, the design planning criteria set out:

> input standards to be used by Essential Energy in planning its network
> requirements for contingency planning methodologies intended to achieve operational outcomes.

59 As per clause S6.1.1(6) of the NER
60 2014-15 non system capital expenditure includes equity raising costs

More specifically, the licence conditions required Essential Energy to maintain the security level at subtransmission substations, major zone substations and subtransmission feeders that supply a load in excess of 15 MVA so that supply is maintained in the event of the single failure of a major component of the network. These works mean that our network is able to supply electricity when critical assets fail.

Compliance with these conditions saw major refurbishment or construction carried out at 147 substations and on 1,501 kilometres of the subtransmission network. In addition over $133 million was spent in our major regional centres to ensure that our customers have an appropriate level of network security. The new security standards have greatly reduced the probability of large scale outages, and allowed for improved operability of our network.

Reliability performance has significantly improved in accordance with the licence conditions that applied in the 2009-14 regulatory control period. Figure 5-2 below shows that an average customer experienced almost 60 minutes more interruption time in 2003, compared to average performance over the last three years.

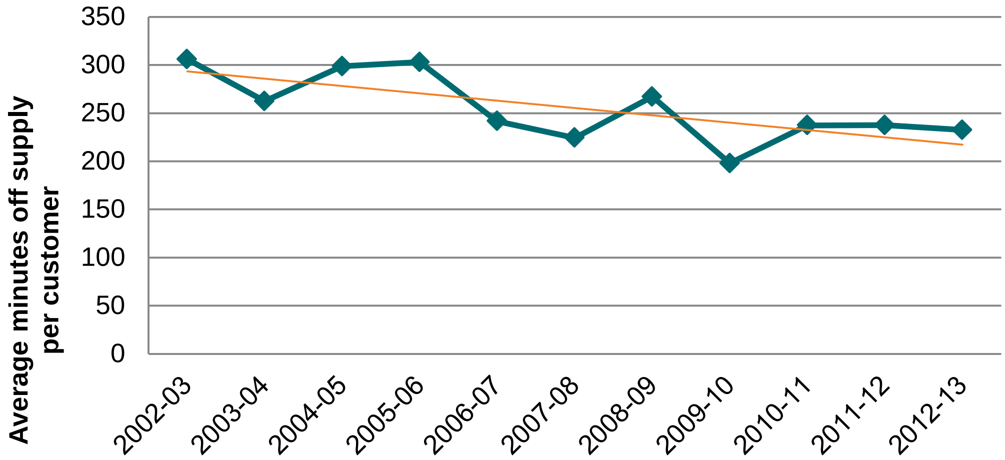

Figure 5-2: SAIDI Performance 2002-03 to 2012-13

The frequency of interruptions has also declined by 26 per cent over this time, from approximately 2.7 outages a year to just under two outages per year. This is illustrated in Figure 5-3.

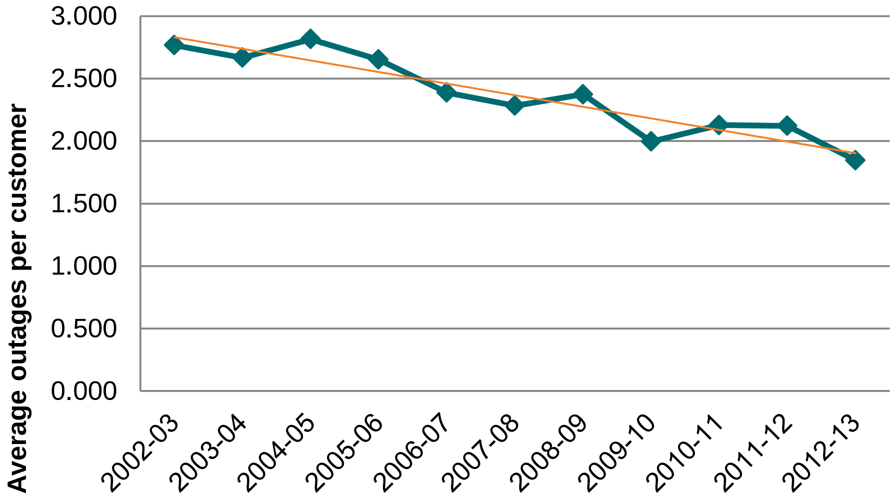

Figure 5-3: SAIFI Performance 2002-03 to 2012-13

During the course of our customer engagement, customers recognised an improved level of reliability and security in our network over the 2009-14 regulatory control period. Customers generally viewed current levels of reliability as acceptable, and for most, a reduction in charges would not compensate for reduced reliability. It also became clear that consumers did not believe that future improvements in reliability were required, particularly not at the expense of higher charges. Moving forward, our expenditure plans will focus on maintaining reliability rather than making improvements in this area.

Reasons for variation to forecast capital expenditure

Essential Energy spent a total of $3.5 billion ($2013-14) in the 2009-14 regulatory control period, approximately 21 per cent lower than the capital expenditure allowed by the AER for the 2009-14 determination. Figure 5-4 below shows that we spent less than the capital expenditure allowance in each year of the 2009-14 regulatory control period, with significant underspends in the last two years. Under the incentive framework, our customers will share in the benefits of this underspend. This is because customers pay lower charges when less capital expenditure is rolled into the RAB.

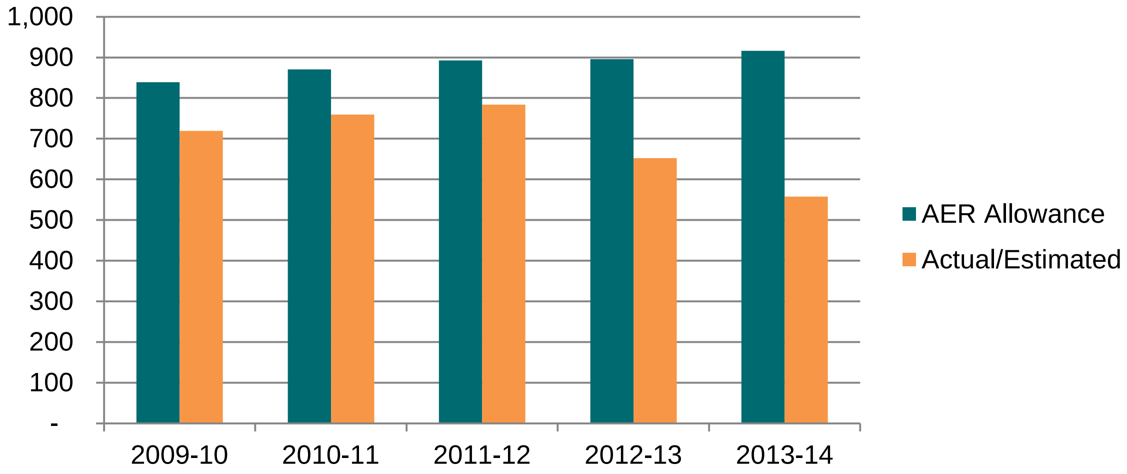

Figure 5-4: Variation to forecast capital expenditure 2009-10 to 2013-14

A relevant consideration for the AER is whether variations to forecast expenditure in the 2009-14 regulatory control period have been explained and addressed in developing forecast capital expenditure for the 2014-19 regulatory control period. This is to provide assurance to the AER and our customers that there are no systematic forecasting errors underlying our proposed capital expenditure programs. In the sections below we identify the key reasons for variations and how these have been addressed in our forecast method for the 2014-19 regulatory control period. A more detailed discussion can be found in Attachment 5.1.

While lower demand growth compared to forecast can explain some of the variations, we note that there have been a number of relevant factors that explain the variations. In particular, we note that the reductions in capital expenditure are substantial in the last two years of the 2009-14 regulatory control period, and this has been fundamentally driven by changes to our capital program as a result of the network reform program. We also note that delivery issues played a part in the lower capital expenditure profile compared to allowances in the early years of the 2009-14 regulatory control period, and that this was related to the significant increase in resourcing required to deliver the program.

Demand growth

Customer activity and demand growth were lower than forecast in the 2009-14 regulatory control period. A consequence was that we spent less capital expenditure to meet increased demand from new and existing customers. The key reasons demand was lower than expected were:

- lower than expected economic growth as a result of the global financial crisis (GFC). At the time of our revised regulatory proposal in 2009, we had not fully estimated the impacts of the GFC on economic growth in NSW
- greater sensitivity to charges than forecast, as a result of changes in network and retail charges
- response to Government policies directed at energy efficiency.

Figure 5-5 illustrates the difference between forecast electricity peak demand and actual and estimated electricity peak demand during the 2009-14 regulatory control period.

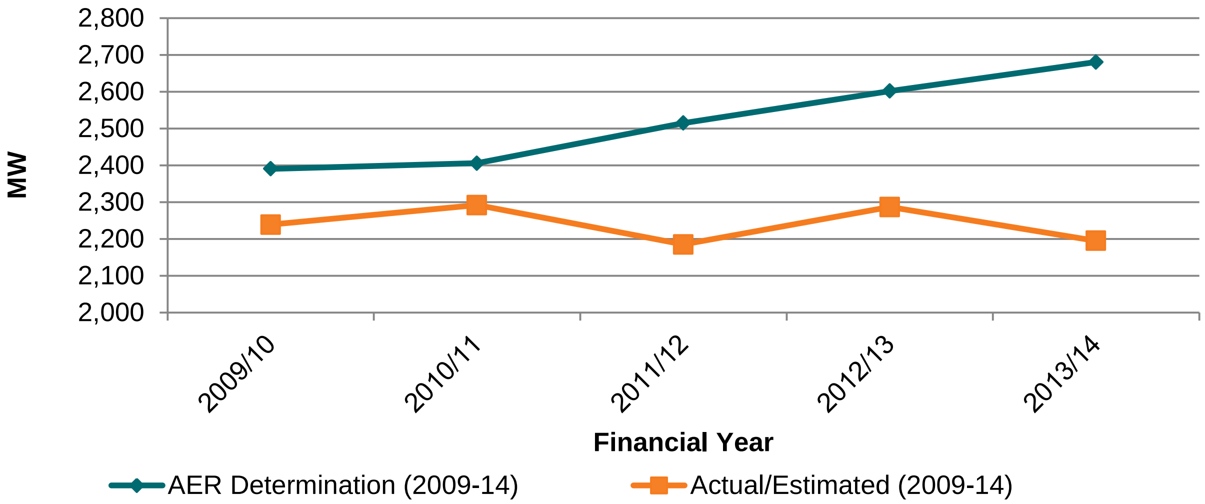

Figure 5-5: Peak demand (MW) 2009-10 to 2013-14

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 Attachment 5.13.

Delivery and prioritisation

The substantial investment program in the 2009-14 regulatory control period placed delivery pressures on Essential Energy in the early years of the period. We responded to these programs through various delivery models, but in some cases our ability to plan and deliver the program fell behind schedule. We consider these delivery issues will not arise in the 2014-19 regulatory control period due to developing better processes, and the reduced workload from a smaller capital expenditure program.

In addition to delivery issues, Essential Energy re-prioritised its program to respond to actual conditions experienced during the 2009-14 regulatory control period, resulting in significant underspends in the final two years of the period. Our forecast capital expenditure for the 2014-19 regulatory control period has incorporated the improvements we have made over the 2009-14 regulatory control period.

Efficiency from network reform program

We recognise that the investment program in the 2009-14 regulatory control period resulted in material variations in charges for our customers. In the last two years of the period, we focused on efficiencies and deferrals to reduce the pressure on charges faced by customers when transitioning to the 2014-19 regulatory control period. A key catalyst was the network reform program of the electricity distribution industry, which has focused on ways of reducing the burden of charges on customers. A more detailed discussion can be found in Attachment E.1.

Network strategy

The purpose of this section is to identify the network strategy that underpinned the development of our capital expenditure forecasts for the 2014-19 regulatory control period.

The overarching purpose of our business is to be of service to our communities by efficiently distributing electricity to our customers in a way that is safe, reliable, sustainable and affordable. Affordability has been a key driver of developing our capital expenditure forecasts, with our primary objective to contain average increases in our share of customers' electricity bills at or below CPI. In doing so, we have responded to concerns raised by customers on the impact of rising network costs on household electricity bills.

Safety is the top priority of Essential Energy. While affordability has been a key focus, we will also be striving to provide a safe and reliable network for our customers. In the sections below we identify the key drivers influencing the development of our capital expenditure program, and the underlying strategies that will address the drivers.

Circumstances influencing investment in the 2014-19 regulatory control period

In developing our network strategy, we have been considered changes in our external and internal environment relative to the 2009-14 regulatory control period. Our forecasts for the 2014-19 regulatory control period have been shaped by the following circumstances:

> We are proactively responding to the concerns of customers regarding electricity charges by identifying opportunities to defer capital expenditure and implement efficiencies. This continues the network reform program introduced in the last two years of the 2009-14 regulatory control period. The efficiency reforms explain a significant decrease in the capital expenditure for the 2014-19 regulatory control period compared to the early years of the 2009-14 regulatory control period. This has impacted all elements of our capital expenditure plans including capacity, replacement and non-system capital expenditure.

> The need for network augmentation has lessened significantly due to a lower overall system peak demand than approved by the AER for the 2009-14 regulatory control period. It is also lower because we have incorporated an expected reduction in the stringency of our licence conditions in planning standards.

> The overall investment portfolio has been refined using an investment prioritisation model that produces an assessed risk ranking for all proposed capital expenditure projects and programs. This has been used in parallel with our planning processes to produce the final capital works program for the 2014-19 regulatory control period based on an acceptable level of risk.

> While we have sought to minimise expenditure, we still need to incur capital expenditure to maintain the reliability and safety of the network. The majority of our proposed investment is to replace existing network assets that are reaching the end of life and exhibiting increasing risk of failure. In the 2009-14 regulatory control period, we have made significant inroads into addressing condition issues. Despite this, the average age of our distribution network has continued to increase, and an ongoing investment program is needed to limit maintenance and breakdown costs, and manage safety (including public safety), environmental and other risks.

> We are investing a modest amount to meet pockets of high demand on our network, including augmentations of the network to meet the needs of new customers. While forecast growth in overall system peak demand is lower than in the past, there is significant diversity between local network areas. This means that the majority of our capacity investment is in specific areas of growing demand or to meet the needs of new customers. Despite the relatively lower level of investment in capacity, we have considered demand management options to defer capital expenditure in a prudent manner wherever possible, and included this in our investment plans.

> We are evolving the process of developing our network strategy to ensure that the priorities and preferences of our customers play a greater role in shaping our network strategy, consistent with the increased emphasis that the NER now place on empowering consumers in their energy choices.

Rising electricity charges

Customers connected to Essential Energy's network are under pressure from the rising cost of living, including their electricity bills which have risen substantially since 2009. While increasing charges are a product of both retail and network factors, we are acutely aware of the fact that our customers expect us to do everything we can to control future increases in network charges. Two years ago, we made a promise to our customers that we would do all that we could to keep our network charges at or below the rate of inflation without compromising safety or the reliability and sustainability of our network.

Our focus is to keep this downward pressure on charges by controlling costs and to keep increases in average distribution network charges at or below CPI for the next five years. Identified cost efficiencies in how we deliver our projects have been incorporated into our forecast capital expenditures. For example, the network reform program has focused on reducing the costs of delivering our capital expenditure programs through improvements in procurement, logistics and the cost of support activities including fleet and IT.

Age and condition of network infrastructure

As outlined earlier in this Chapter, we have undertaken a substantial replacement program throughout the 2009-14 regulatory control period. Despite this, elements of our asset base continue to age, particularly in respect of our distribution assets. If the average age of the network assets is allowed to increase excessively, a significant volume of network assets will be operating beyond their useful lives, with a resultant decline in network security and reliability performance.

Our aim is to ensure that the average age of the network is maintained within an acceptable range that is consistent with reliability and safety obligations. 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. Expenditure programs have been developed to achieve this outcome.

Our approach to asset renewal planning is becoming increasingly strategic and sophisticated as more assets need to be replaced. 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. Network assets will generally be renewed before the point where they fail or are unable to fulfil their performance requirements. 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.

Pockets of demand growth

Essential Energy has experienced a decline in aggregate demand growth rates across its network, which is consistent with most other networks in the NEM. Whilst 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. Our network strategy is focused on ensuring that there is sufficient capacity to meet the demands of new and existing customers in these areas of our network.

We expect only a moderate increase in customer activity and demand in the 2014-19 regulatory control period. However, in such a large and diverse network, global growth figures can often mask the need for local augmentation of the network. Figure 5-6 illustrates this variation in average growth forecast across Essential Energy's operational regions over the 2014-2019 regulatory control period.

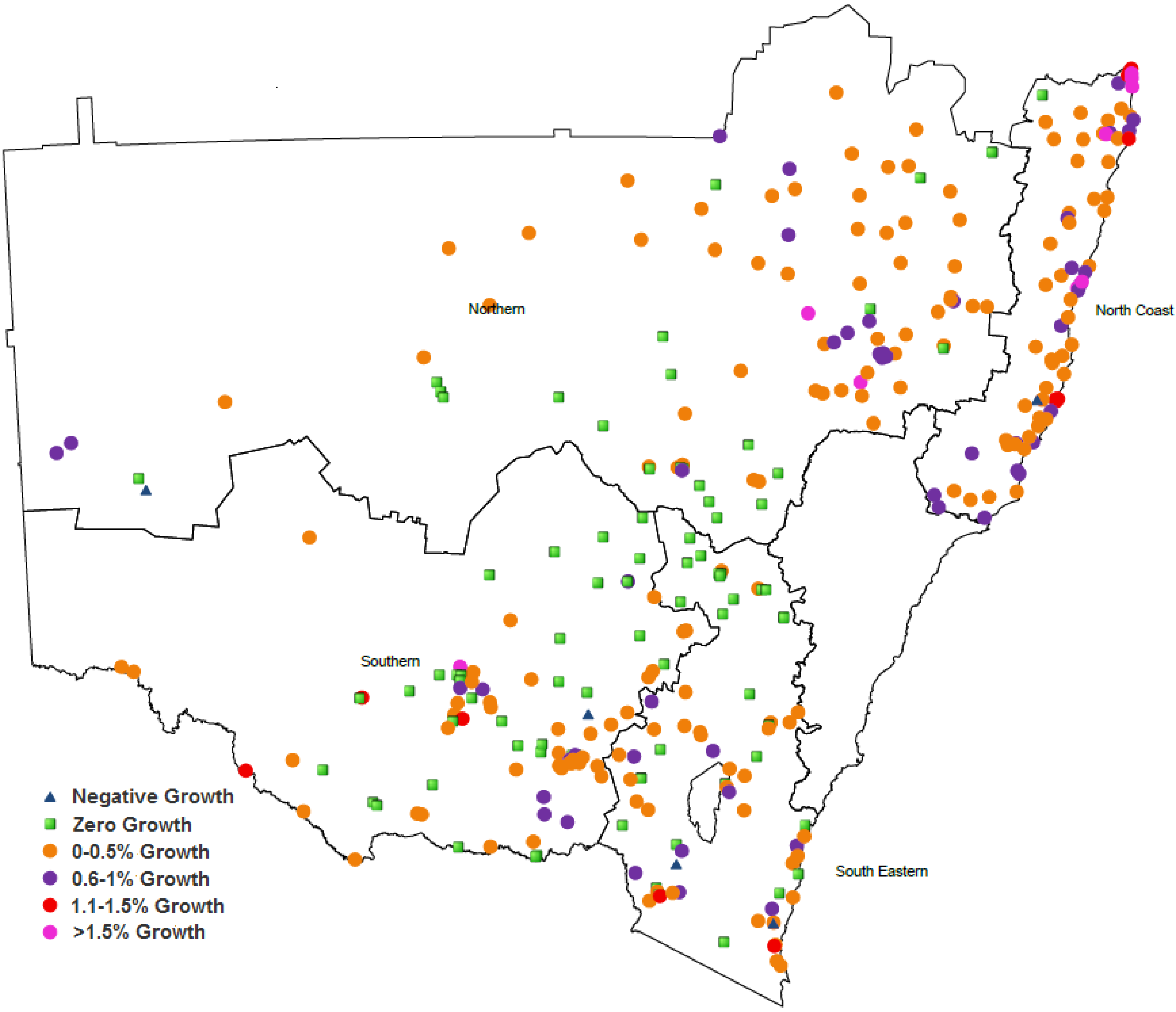

Figure 5-6: Zone Substation Growth (Size) Indicators

The notion of deviations from global demand forecasts is further reinforced by drilling beneath the zone substation level into the distribution feeders. Figure 5-7 below displays summer and winter demand growth rates to 2012 of 1,396 Essential Energy distribution feeders. This chart demonstrates the increased spread of percentage growth rate ranges at the distribution feeder level.

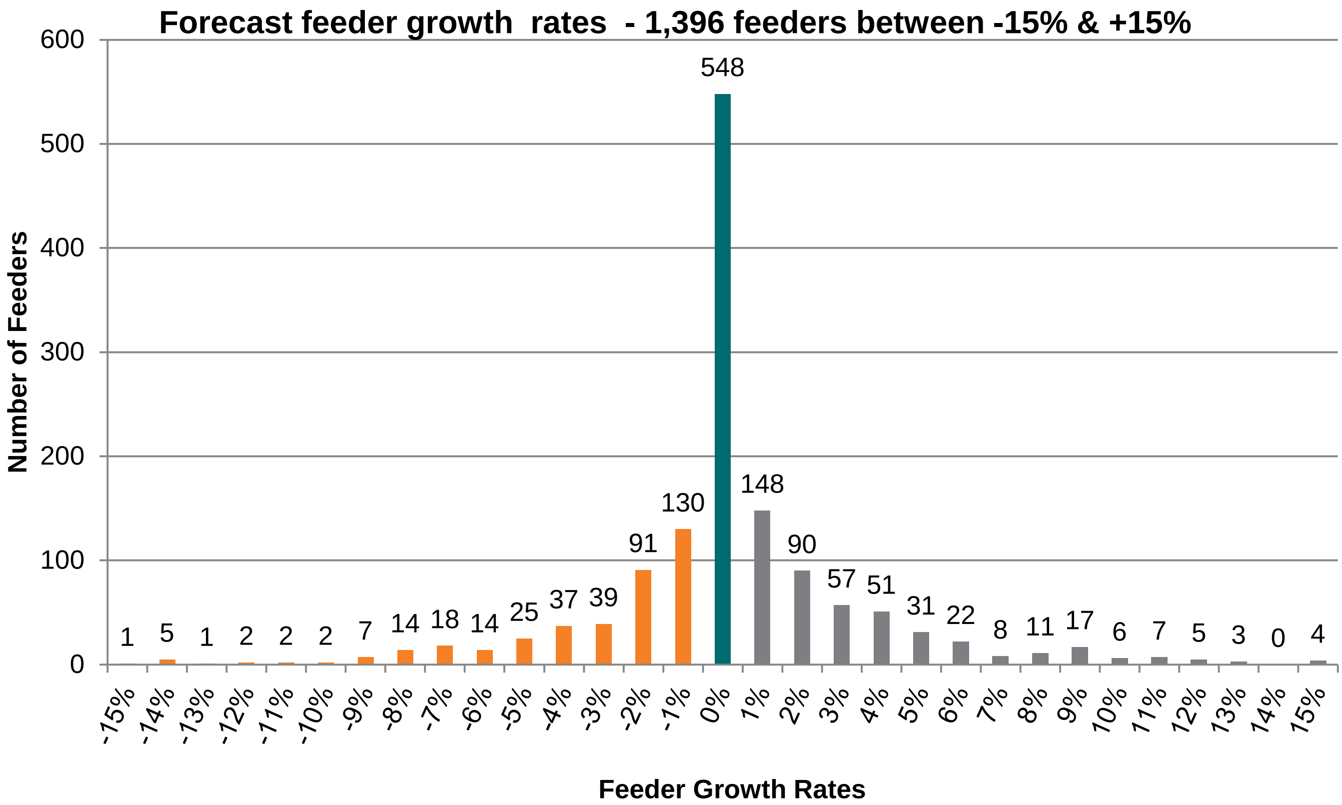

Figure 5-7: Distribution Feeder Growth Rate histogram

At a local distribution feeder level, there is often little apparent correlation to global load or demand forecasts. Although Essential Energy is forecasting a significant reduction in expenditure on subtransmission assets there is still forecast expenditure on distribution assets to ensure we can connect new customers and loads at a local level.

Network strategy enablers

Our network strategy responds to the underlying drivers in the 2014-19 regulatory control period to ensure that our proposed capital expenditure program is efficient and prudent in our circumstances. We have developed a number of underlying strategies to support our network objectives including customer value and engagement, asset management, demand management, and resource planning. Each of these strategies are discussed below.

Customer value and engagement

Through the network reform program, we have developed a common strategy for engaging with our customers. The ultimate goal is to ensure that customers receive an efficient energy distribution service that provides value for every dollar we spend.

A strategic and consistent approach to customer engagement over time will give us greater understanding of our customers' perspectives, and enable us to consider and accommodate their concerns in our planning and decision making processes where appropriate. In particular, we have responded to customers' concerns relating to high charges, and have developed our program in a way that maximises opportunities to defer investment, and leverage efficiencies.

Our plan to engage our customers involves four phases as shown in Table 5-2.

Table 5-2: Summary of Essential Energy's customer engagement plan

Phase 1: Research	Phase 2: Consultation	Phase 3: Delivery	Phase 4: Educate, inform and consult
August 2012	August 2012 – May 2014	May 2014	Ongoing
Customer and stakeholder surveys Customer focus groups Understanding the priorities of customers with regards to network investment	Direct consultation and feedback session with stakeholder and lobby groups Social media channels established and actively moderated to gather customer feedback Customer Council and Rural Advisory Group consultation sessions	Feedback integrated into regulatory proposal and associated documents to support customer priorities in the planning process Deliver customer friendly proposal based on feedback received from stakeholder groups Publication of proposal on website with direct feedback option	Targeted education programs based on customer needs and knowledge gaps Capital project consultation Ongoing and timely customer research Effective customer communications and notifications Online feedback and engagement channels Stakeholder and customer group consultation.

Asset Management Strategy

The asset management framework adopted by Essential Energy recognises that efficient and prudent planning requires a lifecycle view of assets from needs identification, acquisition, and the use, maintenance and disposal of the asset. The asset management framework used by Essential Energy is shown in Figure 5-8.

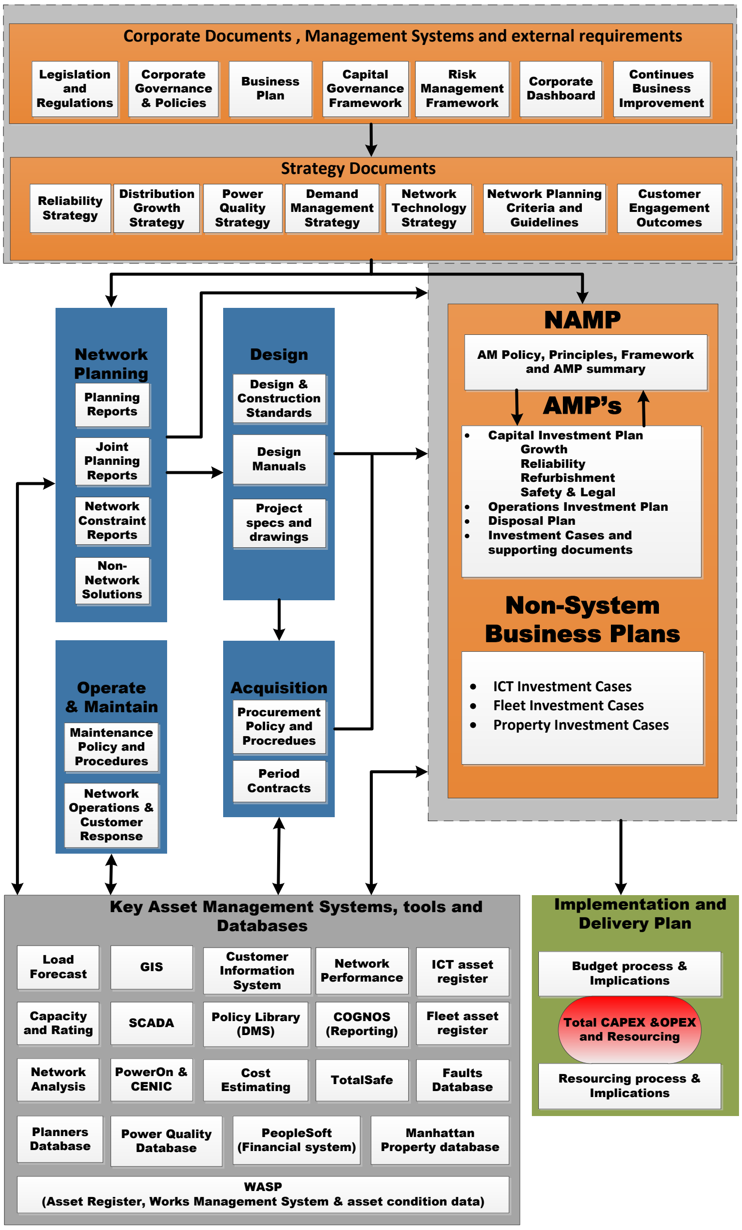

Figure 5-8: Essential Energy's asset management framework

Our asset management is broader than simply maintaining an existing asset. It extends to the identification of needs and the design and acquisition of assets. Design standards are regularly reviewed and challenged as part of our engineering approach. Our delivery methods will continue to utilise a mix of internal and external resources with a view to achieving the most efficient outcome, provide benchmarking data and provide optimisation feedback into our standards and designs. This blend of internal and competitive external sourcing will be progressively enhanced across disciplines over the 2014-19 regulatory control period.

Further detail on our asset management strategy can be found in the suite of supporting documents to the regulatory proposal.

Demand management

Demand management provides opportunities to cost effectively defer investment and pass on these savings to customers in the form of lower charges. When analysing emerging network constraints, the use of non-network alternatives like demand management are an important aspect of optimising the available capacity in the network to meet forecast demand. Demand management techniques are an effective way to manage load factors and are 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.

The decision to apply demand management or to augment the network always remains an issue of economic efficiency, technical feasibility, timing, service preferences, application of sound industry commercial practice, and determining the optimum means of providing supply capacity to customers.

Additional information on our demand management strategy can be found in the suite of supporting documents to the regulatory proposal.

Resource planning

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 contain average increases in our share of customers' electricity bills at or below CPI over the 2014-19 regulatory control period.

A key feature of our delivery strategy for the 2014-19 regulatory control period focuses on optimising the mix of labour between internal and external resources. We will aim to utilise external resources in instances where they are able to safely deliver the desired outcomes more cost effectively than our own resources when required.

Forecast method

The NER require us to describe our method for developing the capital expenditure forecast for the 2014-19 regulatory control period. This provides a level of assurance to the AER and our customers that the forecast method is prudent and efficient.

System assets

System related capital investment covers all system assets comprising the network. Capital investment is undertaken where the asset strategy indicates a need for asset acquisition, construction, renewal, or capacity augmentation. In line with these requirements, capital expenditure can be broken down into a number of categories.

Essential Energy's capital investment program ensures:

- long-term sustainability of network condition, asset utilisation, supply security, and network performance
- adequate capacity for customer connections and peak demand growth, achieved through either capacity augmentation of existing assets or the construction of new assets
- timely replacement or refurbishment of ageing and obsolete assets that have become unserviceable, frequently fail in service, have deteriorated to an unsafe or risky condition, or where the present value cost of maintaining the asset exceeds the cost of replacement
- maintenance of reliability and quality of supply to meet our customer expectations
- environmental, safety, infrastructure security and legal responsibilities are met
- acquisitions of property and easements for future network development
- availability of a number of miscellaneous corporate and non-system items for the continued efficient management and support of the electricity distribution business, including information technology systems, motor vehicles, plant, and other non-system assets.

The capital investment program proposed by Essential Energy in the regulatory proposal is consistent with the delivery of the above outcomes.

Essential Energy's intended capital expenditure program for the 2014-19 regulatory control period and key network asset management strategies are contained in Essential Energy's Asset Management Plans (AMPs).

Asset Management Plans

The AMPs are strategic business plans, used to manage the network assets and deliver service levels to meet stakeholder requirements. Essential Energy has developed 15 AMPs which cover all of its network assets. Each AMP defines the life cycle of a specific group of assets and covers the major drivers of expenditure. The groupings have been chosen to ensure that synergies between assets can be maintained, and to allow the best mix between operating and capital expenditures.

Each AMP defines the service levels applicable to the asset group based on stakeholder requirements, and then compares asset capability and current performance to determine if there is a gap. Targets are defined based on the asset capability and service gap, and strategies are developed to achieve the targets.

These AMPs are supported by a set of strategic plans, planning reports and individual investment cases. The planning process produces a detailed annual capital expenditure program and sets priorities for capacity augmentation, and supply security, quality and reliability over the investment horizon to 2018-19.

Regional planning reports

Essential Energy's regional planning reports identify major subtransmission projects, which may include the augmentation of existing assets or the construction of new assets. The plans encompass forward projections of peak demand and customer growth, and identify the assets on the network that are projected to exceed their limits, and then the subtransmission and distribution network development projects required to address this. This aspect of planning also incorporates Essential Energy's demand-side management activities aimed at containing or reducing the customer load presented to the network, and involves specific developments to maintain security of supply. A bottom-up approach is adopted, with each constraint separately assessed and an individual project report developed.

Distribution network growth strategy

Distribution growth is not a simple extrapolation of global demand forecasting. The sheer scale of Essential Energy's network coverage results in a collection of extremes to be serviced - rural versus urban centres, a multiplicity of communities and industry, population migration to coastal areas, and climatic extremes from inland to coastal, snowfields to sub-tropical forests. This range of extremes turns global averages into statistics that are not always useful at a micro level of decision making.

Historical load growth resulting from factors including uptake in air conditioning and modern appliances, is complicated by the reduction in power quality tolerance, caused by the advent of electronics and integration of microprocessors in appliances. Most of the expansion in demand has imposed added burden on 40 to 50 year old assets that were designed and constructed in a period far removed from the standard of living and customer expectations today.

For further details of our demand forecasting method please refer to Attachment 5.13.

Demand management strategic plan

The decision to apply demand management or to augment the network remains an issue of:

> economic efficiency
> technical feasibility
> timing
> service preferences
> application of sound industry commercial practice
> determination of the optimum means of providing supply capacity to customers.

Performing analysis and consultation around all of these areas to ensure a balanced outcome to the business and our customers in terms of the provision of a safe, efficient and reliable electricity supply is a significant and ongoing process.

A distribution annual planning report (DAPR) is prepared and published by Essential Energy. This document provides historical and forecast peak load data and capacity information for all zone substations, and discloses where a network constraint is forecast to occur within five years. The information allows customers and energy service providers to consider whether they may be able to assist in addressing a network constraint through the implementation of demand management initiatives. This approach actively seeks to minimise barriers and disincentives to the adoption of demand management options.

Reliability strategic plan and the quality of supply strategic plan

The reliability and quality of supply strategic plans address the supply reliability, quality and security aspects of Essential Energy's electricity distribution network business. They detail the specific asset management strategies, commitments, actions, and the level of expenditure aimed at ensuring that supply reliability, quality and security is compatible with minimum standards, and to address identified customer requirements.

Network technology strategic plan

While Essential Energy has for many years used targeted automation schemes to improve network service performance, intelligent network concepts increasingly offer a greater capability to understand, meet and shape the changing needs of customers and the regional communities we serve. In response to our changing environment, Essential Energy is seeking to capture the benefits of intelligent network concepts through a whole-of-business/whole-of-network approach. This approach will promote efficient investment in, and the efficient operation and use of our network services for the long term interests of our customers across regional NSW.

The planning process produces a detailed annual capital expenditure program and sets priorities for capacity augmentation, and the security, quality and reliability of supply over the investment horizon to 2018-19.

Non-system assets

In addition to investing in the electricity network, Essential Energy is also required to invest in non-system assets that support our core activities. These supporting assets are fleet, property, information technology and furniture and fittings. In general, Essential Energy's investment in non-system assets is driven by:

- the condition of the asset
- a new compliance obligation
- alignment with, or enhancement of, Essential Energy's strategic priorities.

Essential Energy has produced a business plan describing the investment and operational plans over the 2014-19 regulatory control period for each of these non-system assets The business plans are supported by investment cases that explain the rationale for the forecast capital expenditure over the 2014-19 regulatory control period.

Categories underpinning capital plans

Our capital plans are an effective way of developing accurate forecasts of capital expenditure requirements for the 2014-19 regulatory control period. Capital expenditure is lumpy in nature, therefore previous expenditure levels cannot be used as a precise guide for forecasting, as is the case for operating expenditure. For this reason, each of the capital plans relies on a methodology which provides a zero base approach to deriving expenditure, which draws on historical data in addition to other factors driving capital expenditure.

Each of our capital plans are based on meeting one or more capital expenditure drivers. Essential Energy only invests in capital when an appropriate driver exists to enable us to meet our regulatory obligations to provide an efficient, safe and reliable network. Our capital expenditure plans have been based on deriving capital expenditure only related to standard control services as follows:

- We have applied our approved cost allocation method (CAM) to ensure our forecast capital expenditure is appropriately allocated to standard control services. The CAM can be found in Attachment 5.10.
- We have applied our proposed connection policy to identify the forecast capital expenditure that relates to standard control services, in contrast to capital expenditure that customers directly fund. Our proposed connection policy is set out in Attachment 5.8. We note that the connection policy approved by the AER as part of the final distribution determination for the 2014-19 regulatory control period will need to be revised each year to include charges for alternative control services that are approved by the AER as part of Essential Energy's annual pricing proposal.
- We have applied our capitalisation policy at Attachment 5.12 to identify the forecast expenditure that is related to capital expenditure, and which sets out the basis on which we capitalise our costs. In this respect, we note that the policy is based on appropriate accounting standards and ensures we do not capitalise operating expenditure[61].

The capital expenditure plans relate to a specific network element or support asset type, and a specific driver of investment for that asset. This is represented in Table 5-3.

Table 5-3: Capital Program Categories

Capital plans	Key forecasting methods			Key plan drivers			
	Sub-transmission	Distribution	Support	Growth	Asset condition and safety	Reliability compliance	Network support
Regional Planning Reports	×			×			
Asset management plans	×	×		×	×	×	×
Distribution network growth strategy		×		×			
Reliability and quality of supply strategic plans	×	×		×		×	
Network technology strategic plan	×	×	×	×	×		×[62]
Demand management strategic plan	×	×		×			
Non-system asset plans		×					×[63]

[61] This information relates to the requirements in Schedule 6.1.1 (8) of the Rules.
[62] The forecast includes a number of initiatives to support productivity savings in the network business.
[63] Fleet forecast capital expenditure includes the benefits from initiatives to reduce fleet cost. These initiatives involve extension of replacement cycle, fleet standardisation and improved buying power to realise maximum value.

Forecast methods for capital plans

This section provides a summary of the approaches used to derive Essential Energy's capital expenditure forecasts:

- a 'base year top down' cost approach for specific asset classes
- a 'bottom up' cost approach is used for individual projects
- removal of one-off costs
- a 'bottom up' forecasting model to identify quantity variations
- applying efficiency factors designed to mitigate the financial impact on our customers of unavoidable upward pressures on our future capital expenditure requirements.

Expenditure at the distribution network level is generally assessed using a 'top down' approach that considers the necessary aggregate investment requirement across broad network asset classes and for different drivers.

Essential Energy has applied a 'bottom up' approach to the analysis of major projects, typically at the subtransmission network and zone substation level, and for some areas, at a high voltage distribution feeder level. This approach uses the best available information, detailed planning and the application of risk management techniques.

These are then drawn together and any synergies identified where a particular investment might meet a number of identified needs.

As part of the network reform program, a new investment governance process has been implemented to review and rationalise our forecast program. A prioritisation model is being used for all network projects and programs. This model uses an algorithm based on an assessment of risks and provides a ranking outcome for the proposed capital expenditure projects. This prioritisation is used to finalise the capital works program for each year based on an acceptable level of risk. This process ensures that the capital expenditure program is efficient and prudent, and meets our objective of keeping charges as low as possible. It should be noted that the resultant expenditure level took into account the prudent risk level in Essential Energy's circumstances, and was not dependent or related to overall risk across all NSW DNSPs.

The capital expenditure forecasts will be reflective of network efficiency programs and reforms. These efficiency programs and reforms have identified improvements across a number of business processes in Essential Energy that result in one-off or ongoing savings, and deferred or avoided costs. The forecasts are also prepared on the basis that current technical standards and accepted sound industry practice will continue to apply during the 2014-19 regulatory control period.

Key assumptions

The NER require us to identify the key assumptions that underlie the capital expenditure forecast, including the method used for developing those forecasts. Summarised in Table 5-4 are the key assumptions that underlie our investment plans for the 2014-19 regulatory control period, with further information provided in Attachment 5.9.

Table 5-4: Key assumptions

Assumptions	Description
Key assumption 1	The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.
Key assumption 2	The capital expenditure 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.
Key assumption 3	Capital expenditure programs have been developed using a strategic management framework that prioritises expenditures for maintaining a safe, reliable and sustainable network.
Key assumption 4	Growth capital expenditure forecasts are derived from the spatial demand and customer connection forecasts included in the regulatory proposal.
Key assumption 5	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 expert independent consultant Independent Economics.
Key assumption 6	The 2012-13 year has been adopted as the efficient base year for deriving a forecast of recurrent operating expenditure.
Key assumption 7	Essential Energy has engaged with stakeholders in developing its regulatory proposal in accordance with the stakeholder engagement process outlined in the National Electricity Rules.

Proposed capital expenditure program

For the 2014-19 regulatory control period, the major component of the capital expenditure program is to replace aged and deteriorated assets on the network. We have also proposed capital expenditure to augment the network to connect new customers and meet localised demand. In addition, we have a small program of works related to reliability, compliance and non-system assets such as IT and corporate property.

Further information on each of our investment plans is contained in the suite of supporting documents to the regulatory proposal. For each plan, we have provided an overview of the investment plans outlining expenditure, drivers of investment, forecast method used, and summary of the program.

Table 5-5 summarises the capital expenditure forecasts required for our network for the 2014-19 regulatory control period. These forecasts align with the objectives of our network strategy and have been prepared in accordance with the key assumptions outlined above. Identification of proposed material projects including the location of the assets, the anticipated or known cost of the proposed assets, and the categories of distribution services which are to be provided by the assets are contained in RIN template 5.1. We note that the forecasts of costs only relate to standard control services[64].

In preparing our capital expenditure forecasts, we have exposed each forecast to internal 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.

[64] This information relates to the requirements of S6.1.1(iii) to (v) of the NER

Table 5-5: Forecast capital expenditure over the 2014-19 regulatory control period ($ million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Growth	189	159	140	135	129	751
Refurbishment	217	233	255	253	257	1,215
Reliability	31	33	33	34	34	165
Compliance	27	36	39	39	40	182
Non System	73	51	52	44	38	257
Total network capital expenditure[65]	537	511	518	505	499	2,570
Equity raising costs	4	0	0	0	0	4
Total capital expenditure	542	511	518	505	499	2,574

Note: Numbers may not add due to rounding

This forecast capital expenditure is expenditure that has been properly allocated to standard control services in accordance with the policies and principles set out in Essential Energy's CAM that was approved by the AER on 9 May 2014. That is:

> capital expenditure that is directly attributable to standard control services are allocated wholly to standard control services. This is the case for all system capital expenditure.
> non-system capital expenditure is allocated to standard control services, alternative control services and unregulated services based on the relevant allocators[66].

Capital expenditure drivers

Capital expenditure for the 2014-19 regulatory control period can be broken down into the drivers described below.

Growth

We augment the network to connect new customers and to address imbalances in supply and demand. We forecast capital expenditure of $751 million for the 2014-19 regulatory control period on growth. There are two drivers:

> New customer connections: This occurs when a new customer connection necessitates augmentation of the shared network. These new connection works make up a large component of the forecast capital expenditure in the 2014-19 regulatory control period.
> Reinforcement: This occurs when the aggregate demand from new and existing customers in an area necessitate augmentation of the shared network. Essential Energy has forecast expenditure designed to accommodate the growth of new and existing customers.

As a result of the significant program of work during the 2009-14 regulatory control period and the low forecast growth over the 2014-19 regulatory control period, growth expenditure is forecast to be lower. The forecast growth expenditure is $521 million, or 41 per cent, below our growth expenditure in the 2009-14 regulatory control period.

An overview of the development of the growth expenditure is provided in the Network Asset Management Plan which is included as Attachment 5.2 to this regulatory proposal. Additional details and supporting information relating to the growth plans are also provided in the suite of supporting documents to the regulatory proposal.

Refurbishment

We undertake renewal and replacement expenditure to ensure compliant infrastructure and to maintain current network reliability levels. Due to our large overhead distribution network, we expect to spend $1,215 million for the 2014-19 regulatory control period on refurbishment. The key driver of refurbishment is the degradation of the condition of assets in the network. One of Essential Energy's largest programs is the replacement of wooden poles. We estimate that over 40,000 poles will need to be replaced during the 2014-19 regulatory control period.

65 Capital expenditure is net of capital contributions and asset disposals
66 For a full list of allocators used, please refer to the CAM in Attachment 5.10

An overview of the development of the refurbishment expenditure is provided in the Network Asset Management Plan which is included as Attachment 5.2 to this regulatory proposal. Additional details and supporting information relating to the refurbishment plans are also provided in the suite of supporting documents to the regulatory proposal.

Reliability

We invest to ensure compliance with reliability performance targets as set out in the licence conditions. The key program requirement for the 2014-19 regulatory control period is work on poor performing feeders. Of the total forecast of $165 million in reliability expenditure, most will go towards strategies aimed at improving the performance of poor performing feeders that support our rural customers, whilst maintaining current reliability levels in areas that meet the licence conditions. Our reliability plans are aimed at maximising past investments and focussing future investments on maintaining the reliability of network performance at current levels.

An overview of the development of the reliability expenditure is provided in the Network Asset Management Plan which is included as Attachment 5.2 to the regulatory proposal. Additional details and supporting information relating to the reliability plans are also provided in the suite of supporting documents to the regulatory proposal.

Compliance

The regulatory obligations that drive our investment program include public safety, workplace safety, and environmental legislation. We expect to spend $182 million for the 2014-19 regulatory control period on compliance. This includes the river crossing project delivery and increased bushfire risk mitigation programs.

An overview of the development of the compliance expenditure is provided in the Network Asset Management Plan which is included as Attachment 5.2 to this regulatory proposal. Additional details and supporting information relating to the compliance plans are also provided in the suite of supporting documents to the regulatory proposal.

Non-System Assets

We plan to invest $257 million in supporting assets to meet network and corporate functions over the 2014-19 regulatory control period. The key drivers of this investment include but are not limited to:

- when the condition of an existing asset is inadequate to perform its function
- if a new compliance obligation necessitates investment in a supporting asset
- improved safety outcomes for our employees, contractors, suppliers and the public
- when a supporting asset will result in an efficiency benefit, resulting in long-term benefits to customers.

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). Our non-system capital expenditure relates primarily to land and buildings, vehicles, furniture and fittings and information communications and technology (ICT). Table 5-6 splits forecast non-system capital expenditure into categories. The total forecast of $257 million is a reduction of 54 per cent ($2013-14) compared to the actual and expected non- system capital expenditure in the 2009-14 regulatory control period.

Table 5-6: Forecast non-system capital expenditure over the 2014-19 regulatory control period ($million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
ICT	37	15	15	10	11	87
Fleet	17	20	23	20	15	94
Land and Buildings	14	10	9	9	7	49
Furniture, Fittings Plant and Equipment	5	5	5	5	5	27
Total Non-System Capital Expenditure	73	51	52	44	38	257

Note: Numbers may not add due to rounding

Information Communications and Technology

The primary role of the ICT function within Essential 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. In the absence of 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.

Essential Energy's regulatory proposal includes total forecast ICT capital expenditure of $87 million.

The proposed capital expenditure is required to achieve Essential Energy's non-system business plan. Each plan 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 major programs of Essential Energy's non-system business plan include the following key investment areas:

> maintenance of existing ICT systems
> improving data management and reporting capabilities
> cyber security management improvements
> necessary upgrade of the PeopleSoft Enterprise Reporting System
> upgrade of the Network Customer Information System.

The ICT business plan can be found in the suite of supporting documents attached to the regulatory proposal. As part of this business plan, we engaged KPMG to conduct an extensive review of our ICT plans and forecast capital expenditure. This included benchmarking our expenditure against other Australian network service providers. Further details of the KPMG review can be found in the ICT business plan provided in the suite of supporting documents to the regulatory proposal.

Fleet

Essential Energy's $94 million (net of disposals) motor vehicle capital expenditure program is directly related to the expected number of staff employed, particularly in field-based roles, who have the highest use of light commercial vehicles, trucks and plant. Essential Energy's forecast fleet expenditure over the 2014-19 regulatory control period primarily comprises replacement expenditure for existing fleet, which is driven by Essential Energy's documented vehicle replacement policies.

Essential Energy is making conscious effort to reduce investment in its fleet by increasing utilisation and better sharing of fleet assets, thus achieving a reduction in overall fleet numbers. Further details can be found in the fleet business plan provided in the suite of supporting documents to the regulatory proposal.

Land and buildings

Essential Energy's $49 million land and buildings capital expenditure program is a result of renewal and compliance based drivers. Essential Energy must accommodate the required number of personnel required to support the forecast program and the associated ongoing maintenance and operational requirements.

Essential 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:

> scheduled element replacement program
> various easement and land purchases
> condition assessment, rectification and compliance program.

Further details can be found in the property business plan provided in the suite of supporting documents to the regulatory proposal.

Furniture, fittings, plant and equipment

Essential Energy's $27 million furniture, fittings, plant and equipment capital program is primarily made up 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.

Further details can be found in the furniture and fittings business plan provided in the suite of supporting documents to the regulatory proposal.

Meeting the rules

Essential Energy has proposed a total forecast capital expenditure for the 2014-19 regulatory control period that we consider is required in order to achieve each of the capital expenditure objectives listed in clause 6.5.7(a) of the rules. The AER is required 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 forecast of required capital expenditure reasonably reflects each of the capital expenditure criteria, having regard to the capital expenditure factors.

To enable the AER to make its decision, the rules require Essential 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. The compliance checklist at Appendix A demonstrates that Essential Energy has provided the information identified in the rules.

In the sections below we briefly identify how we have met the capital expenditure objectives, criteria and factors. In Attachment 5.3 we provide more detailed information.

Meeting the capital expenditure objectives

The rules state that Essential Energy's forecast capital expenditure must be the expenditure that Essential Energy considers is needed to achieve each of the capital expenditure objectives listed in clause 6.5.7(a). These objectives are:

- 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).

Essential Energy's capital plans relate to one or more of the four capital expenditure 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. For example, our jurisdictional obligations require us to meet performance standards, and to provide safe and reliable services. Our support plans set out the investment required to provide support in constructing our network in an efficient manner and to meet our general corporate obligations. In Table 5-7 we show how each of our capital plans relate to one or more objectives.

Essential Energy's forecasting process 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 and alternative control services. The forecast capital expenditure is expenditure that is properly allocated to standard control services in accordance with the CAM approved by the AER on 9 May 2014. The approved CAM can be found at Attachment 5.10.

Table 5-7: Capital expenditure plans and the capital expenditure objectives

Capital expenditure plans	Capital expenditure objectives achieved
Regional Planning Reports	1
Asset management plans	All
Distribution network growth strategy	1 and 3
Reliability and quality of supply strategic plans	2
Network technology strategic plan	All
Demand management strategic plan	All
Non-system asset plans	All

Meeting the capital expenditure criteria and factors

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

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

In making their determination, the AER must have regard to the capital expenditure factors as well as the information included in or accompanying Essential Energy's regulatory proposal, written submissions and any analysis undertaken by or for the AER[67].

We have relied on a report prepared by NERA on behalf of Ausgrid which provides expert economic advice on the interpretation of the expenditure criteria to demonstrate that forecast expenditure reasonably reflects these criteria. This was an update of advice prepared by NERA for Ausgrid for its 2008 regulatory proposal[68] in light of recent changes to the NER. We consider that NERA's advice provides an expert view on the interpretation of the criteria, and therefore we have relied on it when demonstrating how we have met the criteria. NERA's advice can be found in Attachment 5.11.

An important element of NERA's advice is that there are no directly observable measures of efficiency. NERA considers 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 capital expenditure 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 capital expenditure factors represent partial checks of the forecast.

[67] Clauses 6.10.1(b) and 6.11.1(b) of the NER
[68] NERA, *Economic Interpretation of clauses 6.5.6 and 6.5.7 of the National Electricity Rules*, 2008

Forecast process

Our expenditure forecasting process is based on meeting our regulatory obligations, and draws on our expert understanding of the 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 5.3 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 use appropriate methods for identifying investment on different parts of our network and network elements.
- We have a consistent and appropriate method for identifying investment needs 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 forecasting process is the use of a realistic expectation of the demand forecasts and cost inputs, consistent with the capital expenditure criteria in the rules. Essential Energy's planning process has incorporated accurate and up to date peak demand forecasts as part of the key inputs into developing capital plans.

Essential Energy records peak demand at each of its zone areas, and this provides an indication of trends in demand growth at different points in the network. Importantly, Essential Energy's forecasting 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 methods to derive the costs of undertaking projects or programs of work in each capital plan. Our methods 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 regulatory control period.
In Attachment 5.3, we have also addressed the capital expenditure 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 capital expenditure (capital expenditure 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 operating expenditure solutions.
- Essential Energy has considered and made provision for efficient and prudent non-network alternatives (capital expenditure 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 capital expenditure forecasts.
- We have considered the relative prices of operating and capital inputs (capital expenditure factor 6). As noted above we have sought to assess all feasible options when addressing a need including operating and capital expenditure options. When doing so, we have used best practice methods for deriving the relative cost of operating and capital expenditure solutions, and have applied a common method for real cost escalation.
- Our forecast process has considered the concerns of electricity customers as identified in the course of our engagement (capital expenditure factor 5A). We engaged customers on a range of issues including reliability, charges, and demand management. The findings from our customer engagement support the basis of our proposed total capital expenditure including in relation to affordability, and maintaining current levels of safety and reliability.
- Essential 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 capital expenditure for standard control services (capital expenditure 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 the regulatory proposal (capital expenditure 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 rules and are intended to assist the AER in making a decision on whether the total forecast expenditure reasonably reflects the expenditure criteria.

In Attachment 5.3, we have addressed the remaining capital expenditure factors that we consider may represent partial indicators of the efficient level of capital expenditure. In relation to actual and expected capital during any previous regulatory control periods (capital expenditure 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 capital expenditure in the 2009-14 regulatory control period, and consider that these have been taken into account when developing forecasts for the 2014-19 regulatory control period. For example, we consider that lower demand forecasts were a key driver of reduced capital expenditure, and that our demand forecast process has improved considerably in preparing forecasts for the 2014-19 regulatory control period. Further information on our demand forecasting approach can be found in the suite of supporting documents attached to the regulatory proposal.
- Our forecast capital expenditure for the 2014-19 regulatory control period is substantially less than the 2009-14 regulatory control period, and can be explained by key changes in our circumstances. In particular the lower capital expenditure has incorporated the efficiencies we have sought to achieve to make charges more affordable for our customers. While capital expenditure is lower in the 2014-19 regulatory control period, we note that replacement expenditure 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 applies to the DNSP (capital expenditure factor 8). Under the ex-ante incentive regime applied to capital expenditure in the 2009-14 regulatory control period, Essential Energy had strong incentives to prudently and efficiently reduce capital expenditure relative to the AER's allowance.

Essential Energy's actual capital expenditure in the 2009-14 regulatory control period was considerably lower than forecast, particularly in the last two years. In our view, this demonstrates that the reduction in capital expenditure was to improve affordability for customers in the 2014-19 regulatory control period, rather than to gain financial rewards. In this respect, customers benefit the most from reductions to the RAB through lower charges in transitioning to the 2014-19 regulatory control period[69].

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 regulatory control period, providing a partial indication on the efficiency of our total capital expenditure.

The AER must also consider the most recent annual benchmarking report and the benchmark capital and operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period (capital expenditure 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 the regulatory proposal.

[69] The benefits of reductions in capital expenditure have been shared with the customer through a lower value of the RAB, resulting in lower charges when transitioning to the 2014-19 regulatory control period

Essential Energy has developed a comprehensive report at Attachment 5.4 in relation to the benchmarking factor. 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 statistical 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 regulatory proposal, or as a basis to substitute the forecast, given its 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 Guideline 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 7 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 Essential Energy is improving its efficiency over time relative to other peers in the study group.
- We have assessed the relative merits of the repex and augex models that the AER have developed. Our analyses of the models suggest that they 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 analyses of benchmarking tools suggest that trends in a DNSP's results over time are of more value than relative efficiencies between DNSPs at a point in time. In this respect the data provided does demonstrate that Essential Energy's growth rates in expenditure are among the lowest out of the peer group studies. Once again however, we draw caution on such results as they cannot capture the reasons for observed differences between DNSPs.

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 (capital expenditure factor 9). We confirm that our forecast capital expenditure for the 2014-19 regulatory control period does not include any arrangement with any other person that do not reflect arm's length terms.

6. OPERATING EXPENDITURE

Summary

We are proposing $2.3 billion ($2013-14) of operating expenditure for the 2014-19 regulatory control period. This forecast includes a number of initiatives aimed at minimising the impact of necessary increases on our customers.

The purpose of this Chapter is to outline our forecast operating expenditure for the 2014-19 regulatory control period. We explain our performance for the 2009-14 regulatory control period, our circumstances for the 2014-19 regulatory control period, and the plans we have made to absorb unavoidable increases in our operating expenditure requirements. The key points of our proposed forecast operating expenditure are:

1. **We need to keep our network safe and reliable and comply with our obligations.**
   Customers have indicated that they are concerned with network charges, particularly large increases in the past. However, we are also obliged to meet our legislative and regulatory obligations as well as ensuring that the network is safe and reliable. Our forecast operating expenditure reflects these objectives[70].
2. **There are unavoidable upward pressures on our operating costs for the 2014-19 regulatory control period.**
   While our performance during the 2009-14 regulatory control period has provided us with a solid platform going forward, there are necessary increases in our operating expenditure requirements for the 2014-19 regulatory control period. Nevertheless, we expect longer term benefits to result from these rising costs.
3. **We are minimising pressures on charges through efficiency savings.**
   We plan to find efficiency savings to offset unavoidable operating expenditure increases so we can strive to contain average increases in our share of customers' electricity bills at or below CPI.

Our forecast operating expenditure for the 2014-19 regulatory control period represents the expenditure we consider would be required to achieve each of the operating expenditure objectives listed in clause 6.5.6(a) of the rules. It also reflects the expenditure that is properly allocated to standard control services in accordance with Essential Energy's approved CAM.

Our total forecast operating expenditure has been developed to achieve our overarching objectives for the 2014-19 regulatory control period having had regard to our performance during the 2009-14 regulatory control period, and our anticipated circumstances in the 2014-19 regulatory control period. This then informs us of the plans we need to undertake to absorb increases in our operating expenditure requirements so as to achieve our objectives of balancing the need to ensure a safe and reliable network and supply of electricity, complying with our regulatory and legislative obligations, while at the same time striving to contain average increases in our share of customers' electricity bills at or below CPI.

In our approach to forecasting operating expenditure we have considered a primary concern of our customers being high electricity charges in approaching the forecasting of our operating expenditure requirements. In this context, Essential Energy is committed to strategies that deliver future cost savings, and the forecast operating expenditure proposed includes the costs of implementing initiatives to achieve cost efficiencies.

Our proposed forecast operating expenditure therefore:

> Reasonably reflects the efficient amount that a prudent DNSP would require to achieve the operating expenditure objectives based on a realistic expectation of demand forecast and cost inputs.
> Is consistent with and gives effect to the National Electricity Objective (NEO) of promoting the efficient investment in, and efficient operation and use of, electricity services for the long-term interest of customers

[70] These objectives are consistent with the operating expenditure objectives in clause 6.5.6(a) of the rules.

with respect to charges, quality, reliability and security of electricity supply and of the national electricity system[71].

- Includes one off implementation costs required to move to a more efficient operating expenditure structure.

In the remainder of this Chapter, we explain our performance during the 2009-14 regulatory control period and our circumstances for the 2014-19 regulatory control period.

Our performance in the 2009-14 regulatory control period

To appropriately forecast our operating expenditure requirement for the 2014-19 regulatory control period, it is essential to understand our performance during the 2009-14 regulatory control period, particularly with respect to the efficient and prudent benchmark allowance approved by the AER.

Figure 6-1 shows the comparison of Essential Energy's annual actual and expected operating expenditure against the AER approved allowance. It should be noted that the approved and actual/expected underlying operating expenditure includes expenditure relating to all services that are classified as standard control services in the 2009-14 regulatory control period. This includes Type 5 and 6 metering services, ancillary network services and emergency recoverable works[72].

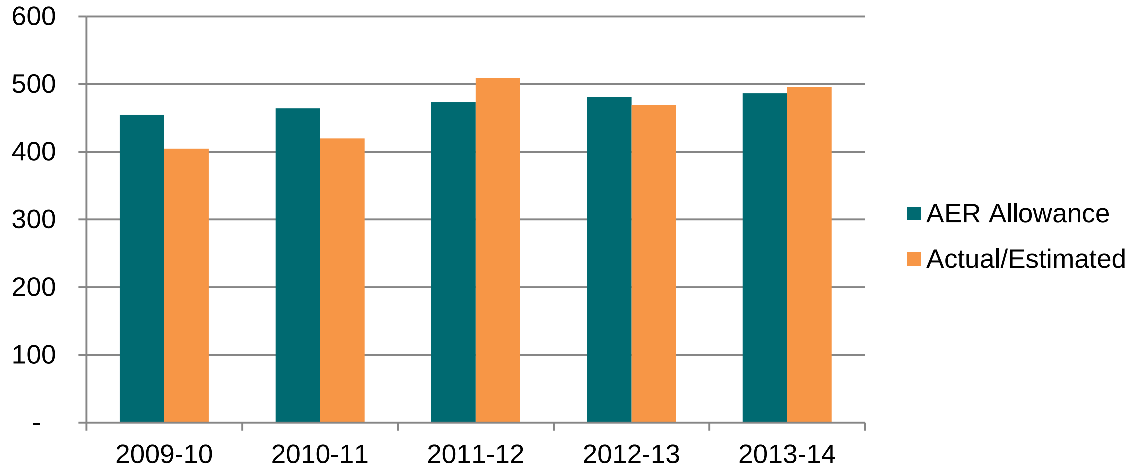

Figure 6-1: Comparison of operating expenditure 2009-10 to 2013-14 ($ million, 2013/14)

The total actual operating expenditure for the 2009-14 regulatory control period is expected to be $2,298 million ($2013-14). This is $62 million (or 3 per cent) below the efficient level set by the AER.

Essential Energy has responded to the incentives within the regulatory framework. We have actively reviewed our strategies, policies, business processes and procedures so as to contain our total operating expenditure for the 2009-14 regulatory control period within or below the efficient benchmark set by the AER. We undertook a number of cost saving initiatives to contain our outturn operating expenditure over the 2009-14 regulatory control period with the main features of the cost reduction initiatives including:

- A streamlined operating model, which has led to significant reductions in employee numbers through the rationalisation and centralisation of corporate and business support functions including finance, human resources, procurement and business services functions;

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71 Clause 7 of the NEL

72 Type 5 & 6 metering services and ancillary network services are classified as alternative control services and emergency recoverable works are not classified from 1 July 2014.

- Review of our policies and procedures to eliminate any discretionary expenditure. For example, we have identified significant cost savings by leveraging the functions of all three NSW DNSPs and by focussing our expenditure on core functions; and
- Targeted capital expenditure and procurement efficiencies including a review of our fleet and procurement policies, processes and procedures to ensure value for money. For example, we have undertaken joint consultancies with other NSW DNSPs to reduce our contracting costs.

The network reform program has been more than simple top down initiatives and has resulted in substantial cultural change at Essential Energy. Changes have included:

- a review of work practices to ensure less overtime is needed to perform core network functions
- reductions in travel expenses by reducing the amount needed for, and the frequency of, travel
- reducing the number of staff who have access to fleet vehicles, resulting in material decreases in fleet costs per employee.

The efficiency improvements and level of savings achieved under the network reform program have been set out in Attachment E.1. In Attachment 5.1, we set out further details of our performance during the 2009-14 regulatory control period with respect to capital and operating expenditures.

Table 6-1 sets out our actual and forecast operating expenditure from 1 July 2004 to 30 June 2019[73]. Table 6-1 confirms a return to to a more steady state level of investment, so much so that total forecast operating expenditure, excluding vegetation management, will fall to levels not seen since 2006-07.

	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
Inspections	13	15	24	27	30	38	42	46	31	32	32	33	33	34	35
Maintenance and repair	41	36	49	52	55	86	72	81	76	80	78	79	81	83	85
Vegetation management	33	43	51	56	79	100	104	152	182	193	163	156	145	148	150
Emergency response	47	49	62	66	69	77	72	80	74	78	79	80	82	84	86
Other network costs	157	159	174	207	156	103	130	149	107	113	111	117	120	118	121
Total network costs	292	301	361	408	389	404	420	508	469	496	464	465	461	467	477

Table 6-1: Operating expenditure 2004-05 to 2018-19 ($million, 2013-14)[74]

Drivers impacting our regulatory proposal for the 2014-19 regulatory control period

Our concerted effort to reduce costs within the 2009-14 regulatory control period has provided us with a solid platform to help meet our objective of containing average increases in our share of customers' electricity bills at or below CPI over the 2014-19 regulatory control period. The actual operating expenditure for 2012-13 represents an efficient starting base from which to forecast our operating expenditure requirements for the 2014-19 regulatory control 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 2009-14 regulatory control period.

[73] As per clause S6.1.2(7) of the NER
[74] Includes forecast DMIA and debt raising costs for the 2014-19 regulatory control period in the other network costs category

Nevertheless, to ensure that our forecast operating expenditure reflects our expenditure requirements for the 2014-19 regulatory control period, we must consider a number of factors that would impact on this expenditure requirement. Generally, some of the factors that influence the level of operating expenditure required in the 2014-19 regulatory control period are:

> regulatory obligations and changes to these obligations or the introduction of new obligations
> Essential Energy's environment and changes to this operating environment since the last determination. The change in operating environment necessitates the costs of implementing initiatives required to move us to a more sustainable and efficient cost structure as a network only business
> the current condition of our assets
> the inherent relationship between forecast capital and operating expenditures
> forecast cost of inputs
> implementation costs supporting network reform program initiatives.

We have considered the impact of these factors on our operating expenditure needs for the 2014-19 regulatory control period. We have used the actual underlying operating expenditure of 2012-13 as the efficient starting base. To this base, we incorporated the impact of the following factors to ensure that our forecast reflects our future needs:

> Forecast changes in the cost of inputs. We anticipate that the rate of increase in labour and materials costs for the 2014-19 regulatory control period to be above the expected CPI.
> Forecast changes in costs due to increases in the size of our network from asset growth.

In addition to this, Essential Energy faces other unique factors in the 2014-19 regulatory control period that will put upward pressures on our costs. These specific factors are:

> Loss of synergy costs from the cessation of the transitional service agreement (TSA) with Origin Energy. These are fixed operating costs which were shared between standard control and unregulated services. With the cessation of the TSA at the beginning of 2014, we have lost the synergy associated with being an integrated business, resulting in increased in operating expenditure needed to provide standard control services.
> Essential Energy operated a gas network in Wagga Wagga and surrounding areas until it was sold to Envestra in October 2010. The gas network continued to operate under a transitional arrangement until the end of August 2011 and utilised many of the same IT systems and business processes as the electricity network. While the scale of the gas network business is smaller than that of the retail electricity business, the selling of the gas network business has also resulted in a loss of synergy that has had to be borne by the electricity network business.
> The impact of the forecast capital expenditure on operating expenditure requirements including the impact of a reduced capital program on our cost structures.

Customer concerns, our performance in the 2009-14 regulatory control period and the circumstances we are expecting to face in the 2014-19 regulatory control period, are critical factors we must take into account in devising strategies to achieve our goal of affordability for customers. In this way, we can effectively address our customers' concerns by keeping forecast operating expenditure to an absolute minimum.

Essential Energy therefore intends to implement efficiency initiatives to minimise the costs impact on our customers. These initiatives are to:

> ensure minimal impact on customers as a result of losing the synergies of being an integrated Network/Retail/Gas business after the cessation of the TSA and transitional arrangements
> eliminate fully the cost impact of excess resources from reduced capital investment over the 2014-19 regulatory control period.

We have therefore forecast a total operating expenditure requirement for the 2014-19 regulatory control period of $2,334 million ($2013-14), shown in Table 6-2. Having taken into account customers' concerns, our performance in the 2009-14 regulatory control period and the circumstances we expect to face in the 2014-19 regulatory control period, Essential Energy considers this is the efficient expenditure that a prudent DNSP would require to achieve the operating expenditure objectives and reflects a realistic expectation of the demand forecasts and cost inputs. Our operating expenditure requirement also supports the necessary investment to continue to drive to an efficient cost structure.

This total forecast operating expenditure has been developed using a method that accounts for all of the factors described above. We explain further below the forecast method used and the impact of the above factors on the operating expenditure requirements for the 2014-19 regulatory control period.

Table 6-2: Total forecast operating expenditure[75] ($ million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Total Forecast Operating Expenditure	464	465	461	467	477	2,334

Forecast method

The rules require us to provide information on the method used for developing the forecast operating expenditure as well as the forecast of key variables and the key assumptions underlying the forecast operating expenditure. Essential Energy's operating expenditure, corporate overhead and divisional overhead strategies can be found in Attachments 6.1, 6.2 and 6.3 respectively[76].

In the previous section we outlined our performance in the 2009-14 regulatory control period, our anticipated circumstances for the 2014-19 regulatory control period, as well our strategies to achieve our overarching objectives in light of these factors. The forecast method we adopted embodies these factors and translates them into a forecast operating expenditure that reasonably reflects:

> 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 cost inputs required to achieve the operating expenditure objectives.

We have adopted a fit for purpose approach to forecasting our operating expenditure for the 2014-19 regulatory control period. This approach is as follows:

> Disaggregate Essential Energy's total operating expenditure into various cost categories[77]. These cost categories represent the costs of undertaking a set of related standard control services (for example inspections, maintenance and repair, vegetation management and emergency response).
> Assess the nature of each cost category and determine the appropriate forecast method that would result in a forecast cost that reasonably reflects the efficient cost that a prudent operator would need to achieve the operating expenditure objectives, based on a realistic expectation of the demand forecast and cost inputs for that particular cost category.

[75] Includes debt raising costs and DMIA
[76] Clauses S6.1.2(2) and (3) of the NER and RIN 10.1(a)
[77] Clause S6.1.2(1) of the NER requires Essential Energy to identify the forecast operating expenditure by reference to well accepted categories.

We consider that this fit for purpose forecasting approach ensures that the nature of each cost category and its relevant underlying drivers are appropriately accounted for, such that the resulting forecast operating expenditure reflects the efficient costs that a prudent operator would require to achieve the operating expenditure objectives. Our total forecast operating expenditure comprises the following broad cost categories with various activities for each category. These are:

- System inspection operating expenditure. The activities within this cost category are:
  - Routine asset inspection
  - Recloser and regulator inspection
  - Equipment earth testing
  - Battery exchange and secondary injection
  - Thermovision inspection
- Maintenance and repair operating expenditure. This cost category covers all maintenance and repair activities on network assets and includes urgent defect rectification.
- Vegetation management operating expenditure. The activities within this cost category are:
  - Aerial patrol
  - Immature tree clearing
  - Hazard tree program
  - Management and administration
- Emergency response
- Other network costs

In addition to the above costs, Essential Energy has also proposed a debt raising cost of $21.2 million ($2013-14) and a demand management innovation allowance (DMIA) of $2.7 million ($2013-14). The methods we used to forecast each of the above cost categories are:

- Base year approach or variants. These variants are:
  - Base year method – variation by volume
  - Base year method – historical trending
  - Base year method – historical averaging
- The bottom up method
- The AER's method for debt raising cost
- The AER's method for the demand management innovation allowance.

Table 6-3 shows the applicable forecast method for each cost category. Each of the forecast methods are further discussed below.

Table 6-3 – Summary of forecast methods

Cost Category	Activities	Base year	Base Year Variation by Volume	Base Year Historical Averaging	Bottom Up	'Top down' approach	Other
Inspection	Routine asset inspection		✓				
	Recloser and regulator Inspection	✓					
	Equipment earth testing	✓					
	Battery Exchange and injection testing	✓					
	Thermovision		✓				
Maintenance and repair			✓				

Cost Category	Activities	Base year	Base Year Variation by Volume	Base Year Historical Averaging	Bottom Up	'Top down' approach	Other
Vegetation management costs	Cyclic Maintenance				✓		
	Aerial patrol				✓		
	Immature tree clearing				✓		
	Hazard tree program				✓		
	Management and administration				✓		
Emergency response		✓		✓			
Other network cost		✓					
Other operating expenditure	Debt raising cost						✓ AER's method
	DMIA						✓ AER's method

Base year method

The base year method is commonly used by DNSPs and the AER to develop forecast operating expenditure. It is also often referred to as the revealed cost method, or base step trend method.

We use this method to forecast the majority of our costs because operating expenditure is largely a recurrent expenditure. The base year method is appropriate for forecasting recurrent expenditure because the base year amount encapsulates the actual annual cost currently required by Essential Energy to provide standard control services[78].

This current actual cost is then adjusted to account for future changes in Essential Energy's circumstances, operating environment, regulatory obligations and changes in demand and cost inputs in arriving at a forecast operating expenditure. This is to ensure that all known factors affecting Essential Energy's future operating expenditure requirements are appropriately accounted for.

Base year method – variation by volume

This method is appropriate where there is an ability to accurately predict the forecast volume of tasks that varies from the base year volume. For example, the required number of planned inspection and routine maintenance tasks is driven by the number of items of equipment and the applicable maintenance cycle and standards. Maintenance cycles are determined on the basis of Failure Modes Effects Criticality Analysis (FMECA), and expenditures are determined on the basis of historical costs adjusted for efficiency.

The average cost per task is comprised of two elements. These are:

> The 'base' average unit cost – this is the actual average cost per task incurred during the financial year 2012-13. It is derived by dividing the total actual operating expenditure incurred by the number of completed tasks.
> Cost escalation – cost escalation is applied to the base average unit cost to calculate the forecast average unit cost for each year of the 2014-19 regulatory control period. The average cost per task is then applied to the forecast volume of tasks to derive the total inspection forecast operating expenditure for the 2014-19 regulatory control period.

[78] 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.

Base year method – historical averaging

We used this method to forecast nature induced breakdown costs. This method is appropriate where there is significant variation in year-to-year expenditure and the base year is not representative of the likely future. This involves taking a historical average of the costs captured during the first four years of the 2009-14 regulatory control period and substituting the average for the base year actual operating expenditure.

Bottom up method

In the instance where the future requirements of a cost category is not a function of the current base year cost, we applied a bottom up method which essentially derives the total forecast operating expenditure by taking into account all the inputs and factors relevant to the activities being performed (for example, number of tasks, the cost inputs required to perform each task, and the charges for these cost inputs).

Forecast of debt-raising costs

Our total forecast operating expenditure also comprises an amount for debt-raising costs. We intend to adopt the method that the AER has been using to derive this cost. That is, the debt raising cost is calculated by applying a benchmark debt-raising unit rate to the debt portion of our regulated asset values. This benchmark debt-raising unit rate is 9.9 basis points per annum. Further detail on this rate can be found in Chapter 7.

Forecast of DMIA

Our total forecast operating expenditure also comprises an amount for the DMIA. We intend to adopt the method that the AER has been using to derive this cost. That is, the DMIA is $0.6 million per annum, less an adjustment in 2015-16 for any DMIA underspend in the 2009-14 regulatory control period. The calculation of this adjustment can be found in Attachment 4.4.

The base year

We have used the actual operating expenditure we incurred in 2012-13 to derive the efficient underlying operating expenditure base. The actual 2012-13 operating expenditure is the latest actual operating expenditure available at the time of preparing the forecast operating expenditure for the 2014-19 regulatory control period. This actual operating expenditure has also been audited and provided to the AER.

We have removed costs relating to activities that have been reclassified by the AER. The AER changed the classification of type 5-6 metering services and ancillary network services to alternative control services and have decided not to classify emergency recoverable works from 1 July 2014. The costs for these services are included in the actual operating expenditure for 2012-13 as these were deemed to be standard control services for the 2009-14 regulatory control period. We must remove these costs from the base operating expenditure to ensure that our forecast operating expenditure for the next five years complies with the rules requirement of reflecting the expenditure for the provision of standard control services, as classified by the AER for the next five years.

Our base year operating expenditure also contains year-end adjustments to reflect actuarial gains and losses in the assessments of our employee entitlement obligations. Actuarial gains and losses are changes in the present value of these obligations. These gains and losses 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. These adjustments need to be made as actuarial assumptions and future discount rates are very difficult to reliably predict over an extended period.

These adjustments are included in our actual operating expenditure for 2012-13 as required by Accounting Standards. However, the adjustments have been excluded from the base operating expenditure to ensure that the base operating expenditure amount, upon which cost escalation and change factors are applied, 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 regulatory control period operating expenditure allowance approved by the AER.

We note that in recent decisions, the AER had 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 liability provisions. 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 has a real potential to result in significant variations in charges to customers as well as imposing further costs on Essential Energy which we must recover from customers. This is fundamentally against the NEO of ensuring the long-term interest of customers with respect to charges.

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 obligation
- a reliable estimate can be made on 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. Essential Energy recognises these liabilities and costs as soon as the employees have rendered their services, for example through an additional year of service.

The cash outlay, however, is made when the employees take the leave to which they are entitled, or upon exit from Essential 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. For example, in the instance of a long-term employee, the amount paid out can be significant as it presents the settlement of a liability that has accumulated over many years. 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 variations in charges.

An accrual approach, on the other hand, helps to alleviate lumpiness in customer charges by ensuring that the costs are recovered at a smoother rate over time, through setting aside amounts as soon as the obligation arises. When the cash is paid, it is drawn from the provision and 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 Essential Energy (and all other DNSPs). These costs will need to be passed onto customers, causing unnecessary increases in charges.

As a result of these concerns about the impact on our customers, we have not adopted the AER’s cash accounting approach.

Table 6-4 details how we have utilised the base year in arriving at our forecast operating expenditure for the 2014-19 regulatory control period.

Table 6-4: Base operating expenditure ($ million, 2013-14)

	2012-13	2014-15	2015-16	2016-17	2017-18	2018-19
Base year operating expenditure	469	469	469	469	469	469
Reclassified ancillary network and meter services	0	(39)	(40)	(41)	(41)	(42)
Actuarial adjustments	0	2	2	2	2	2
Vegetation management efficiencies	0	(19)	(26)	(35)	(35)	(36)
Asset growth escalation	0	2	4	6	8	11
Cost escalation	0	1	4	11	18	25
Accounting treatment changes	0	11	11	11	11	11
Costs to implement network reform program	0	17	22	22	17	17
Other (including savings)	0	16	14	11	13	14
Total forecast operating expenditure	469	459	461	456	462	472

Table 6-5 provides an explanation of how each of the line items contained in Table 6-4 have impacted the base year operating expenditure.

Table 6-5: Factors impacting base year operating expenditure

Factors impacting the base year	Description
Reclassified ancillary network and meter services	Type 5 and 6 metering services and ancillary network services (formerly miscellaneous and monopoly services) have been reclassified as alternative control services for the 2014-19 regulatory control period. Accordingly, we have removed the costs related to these services from our standard control services operating expenditure forecast for the 2014-19 regulatory control period.
Actuarial adjustments to the base year	The adjustment relates to the actuarial assessment of long service leave obligations. This adjustment is necessary to ensure that the base operating expenditure, upon which cost escalation and change factors are applied, represents the underlying ongoing operating expenditure needed to provide standard control services.
Vegetation Management Efficiencies	For the 2014-19 regulatory control period, a decrease in annual vegetation management costs arises due to achievement of efficiencies through a number of strategic reform initiatives further detailed in the vegetation management AMP.
Asset growth escalation	Growth related capital expenditure increases the size of the network and the number of assets to be maintained, operated and managed. This creates a step up in our workload.
Cost 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.
Accounting treatment changes	This reflects the impact of changes to the accounting treatment of certain costs, and is a deviation from the base year treatment of these types of costs.
Costs to implement network reform program	This reflects our ongoing contribution of funds to

Factors impacting the base year	Description
	support the operations of NNSW and associated implementation of operating models.
Other (including savings)	The forecast capital expenditure program represents a substantial decrease compared to the 2009-14 regulatory control 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, reallocating overheads and undertaking additional maintenance expenditure.

As noted in the sections above, our performance in the 2009-14 regulatory control period has set up a solid foundation for us to achieve an efficient forecast operating expenditure for the 2014-19 regulatory control period. This is through our concerted effort to respond to the incentives in the regulatory framework to be efficient. Our customers will also enjoy the fruits of our effort because a lower operating expenditure base amount has been used to derive forecast operating expenditure, as compared to the efficient benchmark set by the AER.

While not reflected in Table 6-4, our forecast operating expenditure reflects a continuation of the significant savings initiatives from the 2009-14 regulatory control period. These savings have been applied across our forecast, eliminating several potential cost increases and reducing the actual upward steps. The key changes are explained in more detail below.

Key variables and assumptions

We outlined the forecast methods used to derive future operating expenditure requirements. The rules further require Essential Energy to include in the regulatory proposal the forecast of key variables relied upon to derive the forecast operating expenditure and the method used to develop these forecasts of key variables. We address this requirement in this section.

There are three key variables in our application of the base year method and its variants. These are:

- actual annual operating expenditure incurred during the 2009-14 regulatory control period
- real cost escalation
- change factors. These comprises of:
    - cost increases to comply with legislative obligations and due to changed circumstances
    - growth factors where applicable
    - efficiency savings to offset necessary cost increases.

Variations to the base year operating expenditure

We use variants of the base year method to forecast our requirements for some inspection and maintenance operating expenditure for the next five years. A key variable in the application of these variants of the base year method are the annual actual operating expenditure we incurred in the first four years of the 2009-14 regulatory control period.

Real cost escalation

The underlying base operating expenditure reflects the current charges for cost inputs. Forecast operating expenditure needs to account for changes in the charges of cost inputs in order to reasonably reflect a realistic expectation of cost inputs required to achieve the operating expenditure objectives in the 2014-19 regulatory control period. These increases in charges may not necessarily be at the same rate as the CPI, due to a number of factors. The need to adjust forward forecasts to take into account real cost escalation is accepted by the AER as important in reflecting the operating expenditure criteria.

Essential Energy applied real cost escalation to the underlying base operating expenditure to derive a forecast operating expenditure that reasonably reflects a realistic expectation of the cost inputs required to achieve the operating expenditure objectives.

Essential Energy identified the total underlying base operating expenditure by cost categories. The total base operating expenditure of each cost category is disaggregated between different cost types. The cost types represent the costs of specific inputs (internal labour, contracted services, labour hire and materials etc) required to undertake the necessary activities to deliver standard control services and to achieve the operating expenditure objectives. For each cost category, we identify and apply the appropriate real cost escalators to each cost type to account for the change in charges for these cost types.

We engaged consultants Independent Economics to provide forecast real labour escalators and CEG to provide forecast real materials escalators. Independent Economics prepared forecasts of labour escalators for the general labour market and the Electricity, Gas, Water and Waste Services Sector (EGWWS). The Independent Economics' and CEG reports and the application of cost escalators are provided at Attachments 5.5, 5.6 and 5.7 respectively. These Attachments detail the methods and data used to develop these forecast labour and material cost real escalators[79].

In addition, we have used the proposed enterprise agreement that provides for an annual pay rise of 2.7 per cent (nominal) on 1 July 2013 and 1 July 2014. This agreement ends in June 2015, one year into the 2014-19 regulatory control period.

Table 6-6 shows the cost types, their descriptions and applicable escalators used.

Table 6-6: Cost escalators applied

Cost types	Nature of the cost type	Real cost escalators applied	
		July 13 – June 15	Remainder of period
Labour	Cost of internal labour.	Essential Energy Agreement	NSW wage price index for utilities industry
Labour hire	Cost of external labour.	Independent Economics forecast for the general labour market.	
Contracted services	Cost of external contractors.		
Materials	Cost of materials used.	CEG for materials, CPI only for other (i.e. no real cost escalator)	
Other	Remaining cost types that make up the total operating expenditure for the cost category.		

We applied our enterprise agreement and the forecast cost escalators prepared by Independent Economics and CEG to derive a total forecast operating expenditure that reasonably reflects the cost inputs in the next five years.

Growth factor

Most of the forecast operating expenditure is associated with the existing asset base. However, growth related capital expenditure increases the size of the network and the number of assets to be maintained, operated and managed. Accordingly, there is a need to establish a relationship between growth related capital expenditure and real increases in operating and maintenance expenditure. Essential Energy has used the approved method from the AER's final determination for the 2009-14 regulatory control period in applying this growth factor to operating expenditure. The calculation of this growth factor can be found at Attachment 6.4.

[79] As required by clause S6.1.2(3) of the NER

Cost increases

We have used the actual underlying operating expenditure of 2012-13 as the efficient starting base. To this base, in addition to real cost escalation, we have also incorporated the impact of the following change factors to ensure that our forecast reflects our future needs. These change specific factors are:

- Loss of synergy costs from the cessation of the TSA with Origin Energy and the sale of the gas network business. These are fixed operating costs that are shared between regulated and unregulated services until the cessation of the TSA and sale of the gas network business.
- The impact of the forecast capital expenditure on operating expenditure requirements including the impact of a reduced capital program on our cost structures.

Cessation of transitional service agreement

Prior to 1 March 2011, Essential Energy was an integrated business that provided both network services and retail services. We provided these services using integrated IT systems and business processes while maintaining ring-fencing arrangements.

Essential Energy's retail business was sold to Origin Energy on 1 March 2011. Under the terms of the sale, a Transitional Service Agreement (TSA) was agreed between Essential Energy and Origin Energy.

The TSA stipulated the provision of retail-related services to Origin Energy retail customers by Essential Energy. Essential Energy provided these services to Origin Energy's customers using the same resources, systems and processes that it employed to provide services to its own retail customers prior to the sale. The last of the services provided by Essential Energy to Origin Energy concluded on 3 January 2014.

On termination of the TSA, our costs of providing standard control services increased due to the loss of scale and scope associated with being an integrated network and retail business. These 'loss of synergy' costs have been factored into the forecast operating expenditure for the 2014-19 regulatory control period. The AER recognised this potential 'loss of synergy' in its draft 2009-14 NSW distribution determination. In accepting the 'Retail project event' (i.e. sale of the retail business) as a nominated pass through event, the AER stated:

> *"If the NSW electricity retail businesses are privatised the DNSP's cost of providing direct control services may increase due to loss of synergies."*[80]

Essential Energy also operated a gas network in Wagga Wagga and surrounding areas until it was sold to Envestra in October 2010. The gas network continued to operate under a transitional arrangement until the end of August 2011 and used many of the same IT systems and business processes as the electricity network. While the scale of the gas network business is smaller than the retail electricity business, the selling of the gas network business has also resulted in a loss of synergy that has had to be borne by the electricity network business. These 'loss of synergy' costs have been factored into the forecast operating expenditure for the 2014-19 regulatory control period.

Mindful of the impact of these increases on our customers, Essential Energy intends to implement strategies to ensure that there is minimal bill impact to customers resulting from these costs increases over the 2014-19 regulatory control period. Our forecast operating expenditure includes the costs of implementing these strategies as well as the savings expected to result from these strategies. We expect all cost increases due to the loss of synergies to be fully offset in our cost structure by 1 July 2016.

Table 6-7 provides the loss of synergy costs associated with the cessation of the TSA, the management savings initiatives implemented by Essential Energy to eliminate their effect, and the residual costs remaining in the forecast operating expenditure in each year of the 2014-19 regulatory control period.

[80] AER, NSW distribution determination 2009-10 to 2013-14 draft decision, 21 November 2009, p280

Table 6-7:Loss of synergy costs and offsetting management savings initiatives ($ million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19
Loss of synergy costs	23	23	23	24	24
Management savings initiatives	20	23	23	24	24
Residual costs	3	1	0	0	0

It is important to note that costs associated directly with retail affected staff who are still employed by Essential Energy are charged against a provision that was created at the time of the sale of the retail business to Origin Energy. Therefore none of these costs are allocated to the network business and are not included in the forecast operating expenditure for the 2014-19 regulatory control period, nor are they included in Table 6-7.

Impact of forecast capital expenditure

Our forecast operating expenditure also accounts for the consequential impact from efficient and prudent capital investment over the 2014-19 regulatory control period, as well as the impact of a lower capital expenditure requirement on support costs and maintenance costs.

For the 2009-14 regulatory control period, the AER approved a significant capital investment program to, among other things, comply with licence conditions mandated by the NSW Government. The licence conditions were needed to address the potential adverse issues arising from under-investment in the past with respect to security and reliability of supply. Our capital expenditure program was also aimed at replacing the aged and deteriorated assets on our network which, if not addressed, could have resulted in large-scale reliability and safety incidents.

The approved capital expenditure program for the 2009-14 regulatory control period was Essential Energy's biggest ever investment. It was a substantial increase on Essential Energy's previous works program and was required to be delivered in addition to our regular maintenance and other works programs.

Looking forward to the next five years, we still have a need to invest to maintain the safety and reliability of our network, but the need for capacity and licence conditions related capital expenditure has subsided. Furthermore, recognising the charging pressures customers are facing and the reduced forecast demand, we have actively reviewed our strategies, policies and planning processes to find efficiencies in our capital works program. As a result, our forecast capital expenditure is approximately 26 per cent ($2013/14) lower than that required for the 2009-14 regulatory control period.

The lower forecast capital expenditure program will not require as many resources as were needed to deliver the approved capital expenditure program in the 2009-14 regulatory control period. These resources were previously tasked with the delivery of the capital program and therefore their costs were fully funded by the capital expenditure allowed by the AER for the 2009-14 regulatory control period. These stranded costs are a legitimate cost to be recovered as part of Essential Energy's operating costs. However, as noted in the following sections, we have savings initiatives in place to deal with these stranded costs over the 2014-19 regulatory control period.

Efficiency savings

Essential Energy's proposed forecast operating expenditure requirement for the 2014-19 regulatory control period is the result of the strategies and initiatives that aim to:

- fully eliminate the cost impact of losing the synergies of no longer being an integrated Network/Retail/Gas business after the cessation of the TSA's
- eliminate the cost impact of excess resources from a reduced capital investment over the 2014-19 regulatory control period.

These objectives will drive efficiency so that we can strive to contain average increases in our share of customers' electricity bills at or below CPI. They will be achieved by management savings initiatives and network reform program initiatives.

Move towards a more efficient cost base

As stated in the previous section, Essential Energy's operating environment and circumstances will change with the cessation of the TSA. Coupled with the significant reduction in the forecast capital investment program for the 2014-19 regulatory control period, Essential Energy is facing a pool of excess resources and other stranded costs, despite the prudent action we undertook in outsourcing the construction of our major substation and subtransmission programs. While this prudent action has minimised the cost impacts of a reduced capital program on the forecast operating expenditure, the impact is still putting upward pressure on the cost base.

This is a critical issue that we have responded to in a measured way, balancing the interests of our employees, customers and shareholders. We need to undertake active measures to respond to the need of constraining the impact of charges on our customers and to ensure an efficient cost structure. To do nothing and maintain a level of resources that is in excess of requirements would not be a prudent option and would impose a burden on customers through charges higher than would otherwise be required.

While Essential Energy would have preferred to redeploy surplus labour requirements to other parts of the business, there is limited scope to do so because:

- the rationalisation of functions across the three DNSPs as part of the NSW Government's industry reform will result in additional surplus requirements rather than vacancies
- the focus on core functions of being a DNSP means that there are limited opportunities in respect of redeployment to Essential Energy's unregulated businesses.

In light of the limited opportunities for redeployment, we have commenced a program to transition our labour workforce over the 2014-19 regulatory control period to a sustainable level. We have begun a 'mix and match' voluntary redundancy program which has been approved by the Australian Taxation Office. Under this program we seek expressions of interest from our eligible employees who may be interested in voluntarily leaving Essential Energy.

The ramp-down in investment and the cessation of the TSA give rise to an inevitable need to evolve our business and to restructure our organisation so that an efficient and sustainable level of resource is achieved such that previously shared fixed costs are now for a network only business. Cost restructuring is a legitimate option and a well-accepted practice by businesses in response to changing needs and circumstances. In our case, it is a prudent course of action having regard to the interests of our customers and our long-term financial viability. While it is a prudent option that ensures customers will not bear the financial burden of maintaining a workforce and other support costs (e.g. property / IT) in excess of requirements, Essential Energy nevertheless is an employer with certain legislative obligations to its employees, some of whom have been with us for a long period of time. We must meet these obligations.

These implementation costs are legitimate expenditure that Essential Energy needs to recover as the efficient costs of providing standard control services. These initiatives represent a prudent option that will result in ongoing cost savings that will ultimately benefit our customers through lower charges. With the departure of these employees, Essential Energy will have a significant lower labour cost profile as well as reduced support costs such as information technology, property, finance and human resources.

Efficiency program

As outlined in Chapter 1 and Attachment E.1, the NSW government instituted network industry reform to drive efficiency across the three NSW DNSPs in a number of key areas. This efficiency drive will remove functional duplication, streamline corporate and support services and create better and faster procurement and logistical processes to achieve value for money.

Table 6-8 illustrates the results of our concerted effort to find efficiency savings for our customers. It shows that without this effort, the cost we need to deliver our services for the next five years would be much higher due to unavoidable cost increases.

Table 6-8:Network reform program savings ($ million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
New operating model initiatives	16	17	18	18	18	86
Policy and strategy initiatives	2	2	3	3	3	13
Strategic sourcing initiatives	6	10	10	10	5	42
Total operating expenditure savings	24	29	31	30	26	141

Key forecast assumptions

The rules require Essential Energy to provide details of the key assumptions underpinning our forecast operating expenditure and a director's certification as to the reasonableness of these key assumptions. Full details of the key assumptions and the directors' certification are provided in Attachment 5.9.

Table 6-9 provides details of key assumptions underlying our forecast operating expenditure. These are assumptions relating to facts or circumstances, the truth or correctness of which underpins, or is highly material to, the forecast of operating expenditure.

Table 6-9: Key assumptions

Key assumptions	Description
Key assumption 1	The Legal Entity, Ownership and Organisational Structure are those in place at the time forecasts are finalised.
Key assumption 2	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 expert independent consultant Independent Economics.
Key assumption 3	The 2012-13 year has been adopted as the efficient base year for deriving a forecast of recurrent operating expenditure.
Key assumption 4	Essential Energy has engaged with stakeholders in developing its regulatory proposal in accordance with the stakeholder engagement process outlined in the National Electricity Rules.

Proposed program

Our forecast operating expenditure program for the next five years aims to ensure that we continue to keep our network safe and reliable, while 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 Essential 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 cost category (if any). Further details underpinning each category are provided in Attachments and supporting documents to the regulatory proposal.

Throughout this section, we will provide information on our total forecast operating expenditure required by the rules so as to meet our compliance obligations.

We propose a total forecast operating expenditure for the 2014-19 regulatory control period of $2,334 million ($2013-14). Essential Energy considers this amount is needed to achieve each of the operating expenditure objectives set out in the rules. This total forecast operating expenditure, includes forecast debt raising costs of $21.1 million and a forecast DMIA of $2.7 million.

Table 6-10 shows the forecast operating expenditure for each regulatory year of the 2014-19 regulatory control period. This forecast expenditure is for the provision of standard control services[81] and represents expenditure that has been properly allocated to standard control services in accordance with the policies and principles set out in Essential Energy's CAM that was approved by the AER on 9 May 2014. That is:

> operating expenditure that is directly attributable to standard control services are allocated wholly to standard control services, for example, forecast maintenance expenditure
> shared costs are allocated to standard control services, alternative control services and unregulated services based on the relevant allocators[82].

Table 6-10: Total forecast operating expenditure ($ million, 2013-14)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Inspections	32	33	33	34	35	168
Maintenance and repair	78	79	81	83	85	406
Vegetation management	163	156	145	148	150	762
Emergency response	79	80	82	84	86	411
Other network costs	107	113	115	113	116	564
Total network operating expenditure	459	461	456	462	472	2,311
Debt raising costs	4	4	4	4	4	21
DMIA	1	0	1	1	1	3
Total forecast operating expenditure	464	465	461	467	477	2,334

Our total business-as-usual forecast operating expenditure is comprised of five cost categories. We discuss these below.

> **Inspections.** Essential Energy has forecast operating expenditure of $168 million on inspections for the 2014-19 regulatory control period. 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), power line to ground and vegetation clearances, thermography of power line and substation structures, and non-destructive testing of power transformers and switchgear. These activities are critical in assessing the current state of distribution equipment and establishing network safety, risks and liabilities that ultimately determine the maintenance work plan. Chemical preservatives are generally applied to wood poles at the time of inspection. Inspection cycles are based on associated risks and utilise both ground inspections and aerial patrols. Inspection criteria are detailed in asset management policies and procedures. All private overhead power lines are inspected on the same basis. The inspection of customer connection equipment ensures compliance with relevant legislative and safety requirements.

> **Maintenance and repair.** This cost category covers all maintenance and repair activities on network assets. Essential Energy forecasts spending $406 million on maintenance and repair during the 2014-19 regulatory control period. This is a stable, on-going maintenance program. Components include maintenance and repair of distribution power line equipment, damaged or inoperable switchgear fuse replacement, distribution substations, and customer service mains.

> **Vegetation management.** Due to the wide expanse and overhead nature of Essential Energy's distribution network, vegetation management is the most significant operating expenditure category in dollar terms. We expect to spend $762 million on vegetation management during the 2014-19 regulatory control period. Our policy is to clear vegetation from power lines in accordance with ISSC3[83]. Compliance with this policy is a

[81] Clause S6.1.2(1)(iv) requires Essential Energy to identify the categories of distribution services to which the forecast operating expenditure relates
[82] For a full list of allocators used, please refer to the CAM in Attachment 5.10
[83] Industry Safety Steering Committee, *ISSC 3 Guideline for Managing Vegetation near Power Lines*, December 2005.

critical control measure associated with management of bushfire risk. The majority of vegetation management work is generated and undertaken in one of two ways:

- A systematic and regular program of vegetation clearance work carried out on power lines based on a prescribed cutting cycle (referred to as cyclic vegetation clearance).
- Spot cutting of defects arising from annual aerial patrols carried out to remove higher risk, individual incursions of vegetation into the clearance envelope.

Spot trimming removes risk quickly but it is not the most efficient measure in the long-term. Our strategy is to keep vegetation to allowable standards by moving to a mainly cyclic vegetation clearing process over a period of time. Recent action has been taken to reduce spot trimming backlogs and shift resources into cyclic trimming. We expect the number of problem areas detected through our annual aerial inspections to be significantly reduced in future.

The total indicative forecast for this regulatory control period has been based on achieving efficiencies through a number of strategic reform initiatives, including the adoption of the approach described above, ensuring appropriate end-to-end management capability and having an adequate vegetation management system as the key enabler. This will deliver the best long-term cost outcome whilst also managing the risks associated with vegetation encroachment on power lines. Forecast work volumes have been determined by statistically significant sampling across the network. Our analysis involves the classification of vegetation density classes and estimating associated unit costs.

The full details of our vegetation management plans and forecast operating expenditures can be found in Attachment 6.1 and the vegetation management AMP attached in the suite of supporting documents to the regulatory proposal.

> **Emergency response.** This covers fault and emergency repair and restoration of supply for planned and unplanned interruptions caused by events such as storms, equipment failures, acts of vandalism, and vehicle collisions. On notification of a customer supply interruption, Essential Energy dispatches field employees to address the fault. We forecast we will spend $411 million on fault and emergency compliance during the 2014-19 regulatory control period.

> **Other network costs.** The main areas of expenditure are network operating activities including supply interruptions and network control, maintenance and repair of zone substations, network divisional operating expenditure, and customer service. The total forecast on other network costs is $564 million for the 2014-19 regulatory control period.

Table 6-11 sets out the extent to which the forecast operating expenditure is fixed or variable in reference to the five cost categories described above[84].

<table>
<tr><th>Operating expenditure category</th><th>Variable driver</th><th>Explanation of variable costs</th><th>Fixed driver</th><th>Explanation of fixed costs</th></tr>
<tr><td>Inspections</td><td>Number of assets and inspection task volumes</td><td rowspan="5">Attachment 6.1</td><td rowspan="5">Overheads are fixed in nature, regardless of the level of Network activity these costs are required to administer and manage the business.

These costs are allocated to the various operating expenditure categories and hence form part of total costs.</td><td rowspan="5">Attachment 6.2

Attachment 6.3</td></tr>
<tr><td>Maintenance and repair</td><td>Asset failure, number of assets</td></tr>
<tr><td>Vegetation management</td><td>Seasonal growth, inspection and defect cycles</td></tr>
<tr><td>Emergency response</td><td>Emergency outage response activity, number of assets</td></tr>
<tr><td>Other network costs</td><td>Number of zone substation assets, customer response volumes</td></tr>
</table>

Table 6-11: Fixed and variable forecast operating expenditure ($ million, 2013-14)

Efficiency costs and savings

In addition to this business as usual operating expenditure, Essential Energy's proposed forecast operating expenditure for the 2014-19 regulatory control period includes the one-off efficiency initiatives implementation costs and consequential benefits discussed above. These benefits will deliver to customers a lower cost base as we enter into the 2019-2024 regulatory control period.

Meeting the rules

Essential Energy has proposed a total forecast operating expenditure for the 2014-19 regulatory control period that we consider is required in order to achieve each of the operating expenditure objectives listed in clause 6.5.6(a) of the rules. 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, having regard to the operating expenditure factors.

To enable the AER to make its decision, the rules require Essential Energy to comply with specific information requirements in clause 6.5.6 and schedule 6.1.2. This includes an obligation to comply with the requirements of any relevant regulatory information instrument. The compliance checklist at Attachment A demonstrates that Essential Energy has provided the information identified in the rules. In the sections below we briefly identify how we have met the operating expenditure objectives, criteria and factors. In Attachment 5.3, we provide more detailed information.

[84] As per clauses S6.1.2(1)(iii) and (iv) of the NER

Achieving the operating expenditure objectives

The rules state that Essential Energy's forecast operating expenditure must be the expenditure that Essential Energy considers is needed to achieve each of the outcomes listed in clause 6.5.6(a), known as the operating expenditure objectives. These objectives are[85]:

- 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, Essential Energy must have the necessary capabilities, personnel and systems to undertake the necessary activities to achieve these objectives. 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 order to achieve this objective, Essential Energy must have the capabilities, personnel and systems to undertake maintenance on the electrical network. Consequently, in undertaking these activities and in operating the necessary systems, Essential Energy must incur maintenance operating expenditure.

Essential Energy's total forecast operating expenditure therefore comprises of the costs of undertaking all the related activities and to operate the necessary systems to deliver each of the operating expenditure objectives listed above. Essential Energy's total forecast operating expenditure comprises of the cost groups in Table 6-12 and it shows the operating expenditure objectives that each cost group delivers.

Table 6-12: Operating expenditure cost groups and objectives

Operating expenditure cost group	Activities	Operating expenditure objectives achieved
Inspection	Inspection operating expenditure is required to undertake various inspection activities on Essential Energy's electrical network. These activities, and hence the associated cost, are critical in achieving all four operating expenditure objectives.	All operating expenditure objectives
Maintenance and repair	Maintenance and repair operating expenditure is required to undertake various maintenance activities on Essential Energy's electrical network. These activities, and hence the associated cost, are critical in achieving all four operating expenditure objectives.	All operating expenditure objectives
Vegetation management	Essential Energy's vegetation management operating expenditure relates to expenditure on maintaining the clearance of vegetation from the network. These activities, and hence the associated cost, are critical in achieving all four operating expenditure objectives.	All operating expenditure objectives
Emergency Response	Emergency response operating expenditure is required to carry out response to failure of the network. These activities, and hence the associated cost, are critical in achieving all four operating expenditure objectives.	All operating expenditure objectives
Other network costs	Other network costs cover network operating activities including supply interruptions and network control, maintenance and repair of zone substations, network divisional operating expenditure, and customer service. These activities, and hence the associated cost, are critical in achieving all four operating expenditure objectives.	All operating expenditure objectives

85 See clause 6.5.6(a) of the NER for exact wording.

Operating expenditure cost group	Activities	Operating expenditure objectives achieved
Demand management	Essential Energy's demand management operating expenditure is required to manage the demand on our network through various non-network alternatives and the demand management innovation scheme. This expenditure is required to achieve the operating expenditure objective 1.	Operating expenditure objective 1

Meeting the operating expenditure criteria and factors

The AER must accept Essential 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 cost 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 Essential Energy's regulatory proposal, written submissions and any analysis undertaken by or for the AER[86].

We have relied on a report prepared by NERA on behalf of Ausgrid which provides expert economic advice on the interpretation of the expenditure criteria to demonstrate that forecast expenditure reasonably reflects these criteria. This was an update of advice prepared by NERA for Ausgrid for its 2008 regulatory proposal[87] in light of recent changes to the NER. We consider that NERA's advice provides an expert view on the interpretation of the criteria, and therefore we have relied on it when demonstrating how we have met the criteria. NERA's advice can be found in Attachment 5.11.

An important element of NERA's advice is that there are no directly observable measures of efficiency. NERA considers 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 operating expenditure 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 operating expenditure factors represent partial checks of the forecast.

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 5.3 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.

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[86] Clauses 6.10.1(b) and 6.11.1(b) of the NER

[87] NERA, *Economic Interpretation of clauses 6.5.6 and 6.5.7 of the National Electricity Rules*, 2008

In terms of forecasting operating expenditure for the 2014-19 regulatory control period, we have adopted a fit for purpose approach that comprises the following steps:

> Disaggregate Essential Energy's total operating expenditure 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 operating expenditure objectives.
> 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 operating expenditure objectives, based on a realistic expectation of the 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 operating expenditure is reflective of the efficient costs that a prudent operator would require to achieve the operating expenditure objectives. This process gives us confidence that our total forecast operating expenditure would reasonably reflect the operating expenditure criteria and ensures that the NEO and the RPP are met, especially that we are afforded a reasonable opportunity to recover at least the efficient costs we expect to incur in the 2014-19 regulatory control period.

This approach to forecasting total operating expenditure that selects the most appropriate methods for the relevant cost categories would be expected to be the approach that a DNSP would undertake to ensure that the resulting forecast expenditure reasonably reflects the operating expenditure 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 and scope for efficiency savings, we also have had regard to the operating expenditure factors in the rules that the AER must consider in deciding whether it is satisfied that our total forecast operating expenditure reasonably reflects the operating expenditure 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 operating expenditure is to reasonably reflect the operating expenditure criteria.

In Attachment 5.3 we have also addressed the operating expenditure 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 operating expenditure (operating expenditure factor 7). A key step in our expenditure forecasting process is to consider the full range of alternative options, including areas where there may be operating expenditure solutions such as maintenance, which have then been factored into our operating expenditure forecasts.
> Essential Energy has considered and made provision for efficient and prudent non-network alternatives (operating expenditure 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 operating expenditure forecasts.
> We have considered the relative prices of operating and capital inputs (operating expenditure factor 6). As noted above we have sought to assess all feasible options when addressing a need including operating and capital expenditure options. When doing so, we have used best practice methods for deriving the relative cost of operating and capital expenditure solutions, and have applied a common method for real cost escalation.
> Our expenditure forecasting process has considered the concerns of electricity customers as identified in the course of our engagement (operating expenditure factor 5A). We engaged customers on a range of issues including reliability, charges, and demand management. The findings from our customer engagement support the basis of our proposed total operating expenditure including in relation to affordability, and maintaining current levels of safety and reliability.
> Essential Energy's forecast method considered whether any operating expenditure should be identified as a contingent project, and therefore excluded from the total forecast operating expenditure for standard

control services (operating expenditure factor 9). We found that no component of our operating expenditure cost categories met the criteria of a contingent project set out in 6.6A.1 of the rules.

- Our forecasting process identified that there have been no final project assessment reports at the time of submitting this proposal (operating expenditure 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 rules and are intended to assist the AER in making a decision on whether the total forecast expenditure reasonably reflects the expenditure criteria.

In Attachment 5.3 we have addressed the remaining operating expenditure factors that we consider may represent partial indicators of the efficient level of operating expenditure. In this respect, the rules require the AER to give regard to actual and expected operating expenditure during any previous regulatory control periods (operating expenditure factor 5), and whether the operating expenditure forecast is consistent with any incentive scheme or schemes (operating expenditure factor 8)

Essential Energy was subject to the EBSS in the 2009-14 regulatory control period. The EBSS provides incentives for business to pursue efficiency improvements in operating expenditure and to share efficiency gains with customers. Our performance in the 2009-14 regulatory control period has set a solid platform for Essential Energy in ensuring that the forecast operating expenditure for the 2014-19 regulatory control period reasonably reflects the efficient costs that a prudent operator would need to achieve the operating expenditure 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 and operating expenditure that would be incurred by an efficient DNSP over the relevant regulatory control period (operating expenditure 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, therefore we are not provided with an opportunity to demonstrate or make representations on this report at the time of submitting the regulatory proposal.

Essential Energy has developed a comprehensive report at Attachment 5.4. The report examines the inherent limitations in 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 an inability to conduct ‘like for like’ analysis across peer firms, data inconsistency and inaccuracy, and failure to meet statistical 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 regulatory 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 Guideline 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 7 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 Essential Energy is improving its efficiency over time relative to other peers in the study group.

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 DNSPs results over time is of more value than relative efficiencies between DNSPs at a point in time. In this respect the data provided does demonstrate that Essential Energy's growth rates in expenditure are among the lowest out of the peer group studies. Once again, however we draw caution on such results as they cannot capture the reasons for observed differences between DNSPs.

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 (operating expenditure factor 9). We confirm that our forecast operating expenditure for the 2014-19 regulatory control period do not include any arrangement with any other person that do not reflect arm's length terms.

7. ALLOWED RATE OF RETURN

We propose a rate of return on capital of 8.83 per cent 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 customers 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. [88] Our key contentions are as follows:

> We propose a rate of return of 8.83 per cent, which is commensurate with the minimum efficient financing costs for a DNSP with a similar degree of risk as that which applies to Essential Energy over the 2014-19 regulatory control 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 cost of equity would provide return profiles are 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 per cent, which has been calculated consistent with a ten 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 2014-19 regulatory control period. Attachment 9.2 sets out our proposed method for annually updating revenue allowances for changes in the cost of debt.
> We have serious concerns with the AER's proposed ten year transition path to the trailing average. As Essential Energy has historically issued debt on a benchmark efficient staggered portfolio basis, the AER's debt transition would significantly under compensate Essential Energy based on current forecasts of yields on ten 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 (RPP) outlined in section 7A of the NEL and should not be applied to Essential 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 until the 2024-29 regulatory control 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 per cent, 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 evidence from relevant financial models including the CAPM (both the Sharpe-Lintner and Black versions), the dividend growth model (DGM), and the Fama-French 3 Factor Model (FFM).

Overall rate of return

The NSW DNSPs have consistently advocated for a return on capital that is based on long term observations of financial market data and 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

[88] As required by S6.1.3(9) of the NER.

control period) on regulated revenues and consequently consumer charges over time. Our proposed rate of return incorporates the following:

> A ten year trailing average 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 in the presence of refinancing risks[89]. Annual updates also ensure that changes in debt costs can be gradually incorporated into customer charges rather than through large movements in charges between regulatory control 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 control period.

Our proposed rate of return has been developed to meet the requirements of the NER to contribute to the achievement of the NEO set out in section 7 of the NEL, and to be consistent with the RPP 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 Essential 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 NER requirements, we propose a rate of return of 8.83 per cent. 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 Essential Energy over the 2014-19 regulatory control period.[90]

The cost of debt has been estimated using a ten year trailing average approach that will be subject to annual updates throughout the 2014-19 regulatory control period. We propose an automatic approach to annually updating the cost of debt using data published by the Reserve Bank of Australia (RBA), and 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 efficient entity facing similar risks as Essential Energy. This transition exposes Essential Energy and our customers to undesirable volatility and risk. The transition would, if implemented when rates remain at current levels, significantly under compensate Essential Energy. If the AER was to apply a transition to the trailing average for Essential 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 RPP or the NEO, which require that a DNSP 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.

[89] AER, *Explanatory statement on the rate of return guideline*, December 2013, p23

[90] As required by clause 6.5.2(c) of the NER.

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[91] and evidence from relevant financial models including the CAPM, the DGM, and the FFM.[92] The breakdown of our proposed rate of return is outlined below in Table 7-1 .

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 Essential Energy's approach to the rate of return are set out in a report from CEG which can be found in Attachment 7.1. We note that the CEG report references an extensive number of relevant documents and expert reports, which are all provided for completeness and included in Attachments 7.2 to 7.28.

Table 7-1: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 credits	25%	25%

Cost of debt

Throughout the development of its rate of return guideline, the AER has recognised that in the presence of refinancing risk, the benchmark efficient practice is to issue debt on a staggered portfolio basis.[93] 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 guideline, the AER proposed to estimate the allowed return on debt for energy network firms using a trailing average approach.[94] We agree that the allowed return on debt should be estimated using a trailing average approach.

Essential Energy's proposed approach

Essential Energy proposes a trailing average return on debt allowance using yields on ten year BBB+ and BBB rated Australian corporate bonds over the past ten 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 ten years. We propose a 7.98 per cent trailing average cost of debt, which is based on the following:

- An immediate application of the ten 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 ten 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 to determine the benchmark efficient credit rating for energy network firms.

[91] As required by clause 6.5.2(g) of the NER.
[92] As required by clause 6.5.2(e)(1) of the NER.
[93] AER, *Explanatory statement, Rate of return guideline*, December 2013, pp. 104-105.
[94] AER, *Final rate of return guideline*, December 2013, section 6.3.1, p. 19.

> An extrapolation of the RBA curve to an effective tenor of ten years, which is necessary to achieve a ten year trailing average, since the RBA forecast has an effective tenor shorter than ten 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 Attachment 7.1. 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 off and be replaced by data contained in the RBA dataset from 1 January 2005 onwards (in calculating the 2015-16 trailing average).

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 Table 7-2.

Table 7-2: 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 7-1, which provides the full time series of RBA data used to calculate the trailing average from 1 January 2005 to 30 December 2013.

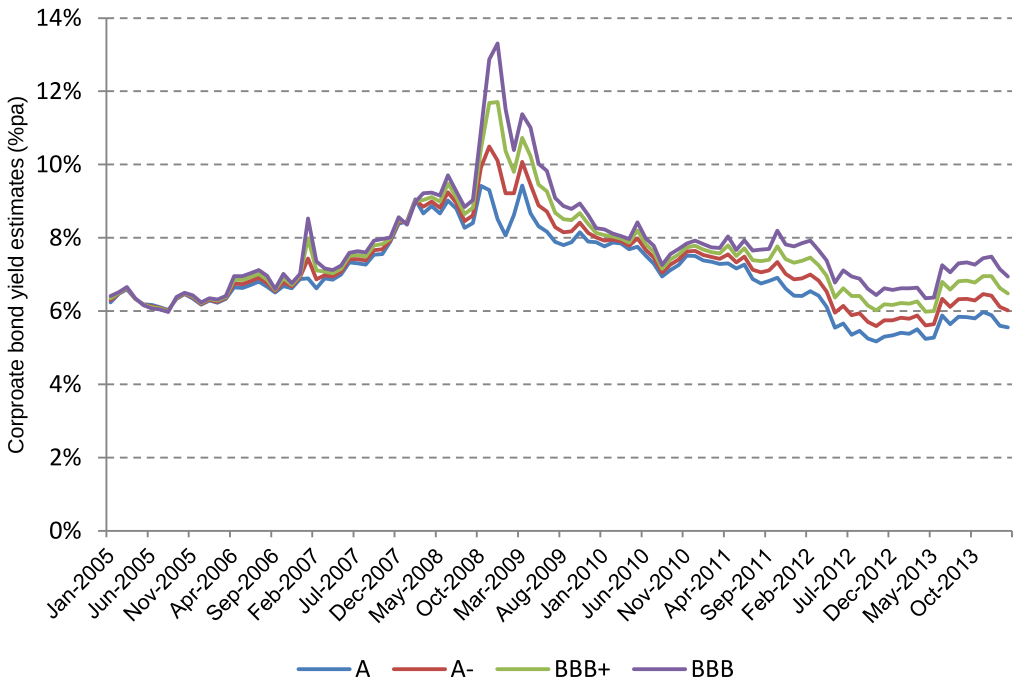

Figure 7-1: Time series of RBA cost of debt by credit rating
Source: RBA, CEG analysis , A-/BBB is calculated as 2/3 weighting to A/BBB and 1/3 to BBB/A-

As illustrated above, varying the benchmark credit rating in the years 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 and 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 dataset for determining the benchmark efficient firm and would under compensate Essential Energy. We consider that it is appropriate to hold this benchmark credit rating constant for the five years of this regulatory control 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 Attachment 7.1.

The trailing average approach

A trailing average cost of debt will ensure that customer charges 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 crisis, corporate bond yields became much more variable over short periods of time as demonstrated in Figure 7-2, demonstrating that a short term averaging period cannot be presumed to be sufficient to smooth variability in corporate bond yields over time.

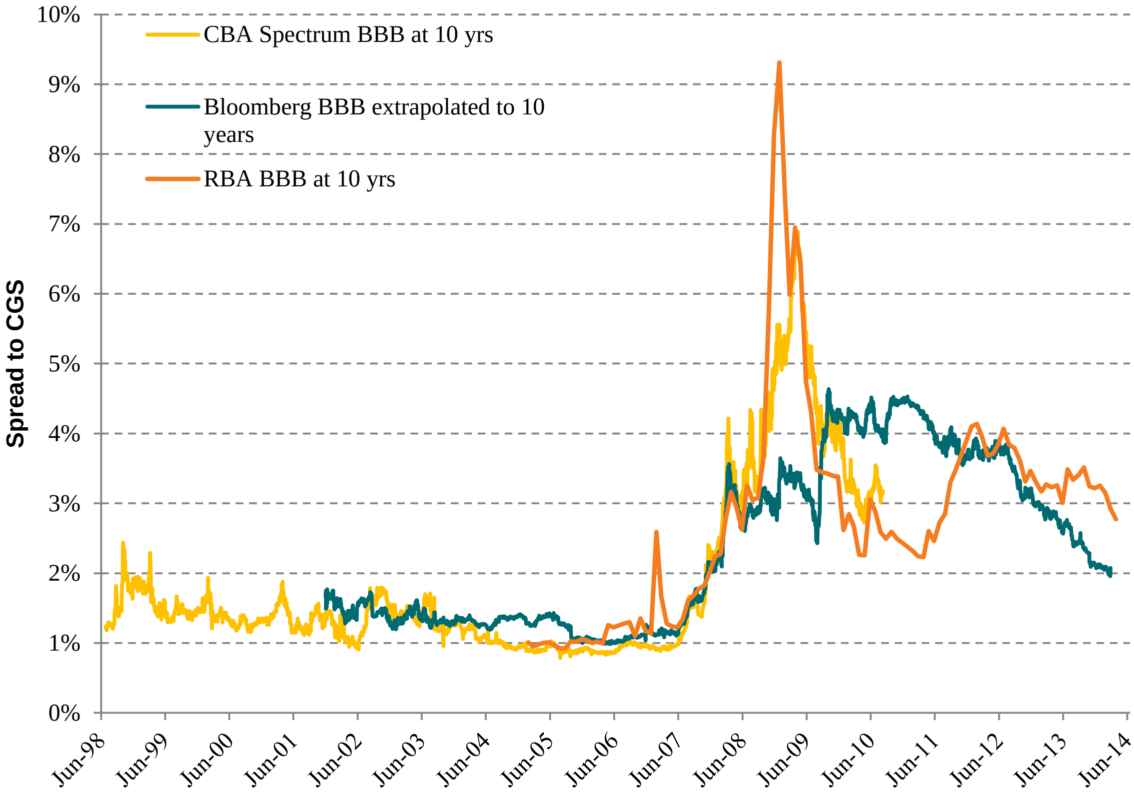

Figure 7-2: Corporate bond spreads to ten year CGS yields[95]

[95] 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, for example by issuing significant tranches of debt over their nominated[96] 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 business to significant refinancing risks[97]. These risks include that:

- the business could be forced to access debt/hedging markets at times that were generally or specifically unfavourable 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.

A trailing average approach would have ensured more stable debt allowances (and customer charges) over time. It would also reduce the potential for measurement error to affect the regulatory allowance. The potential for measurement error is illustrated by the periods when Bloomberg and RBA/CBASpectrum estimates departed from each other significantly. Under the trailing average approach, 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 matching 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 the cost of corporate debt issued over a short term averaging period (a synthetic hedge).

However, given the significant size of Essential 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 Essential Energy's benchmark debt portfolio was approximately $3.8 billion in 2009, the refinancing risk would simply have been too great for Essential Energy to expose itself to in the face of short term variability in financial markets. We note that in the face of the GFC, Essential Energy would have been refinancing its 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, Essential Energy would have been attempting to lock in a five 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 five year swaps and CGS was at historic high levels (around 120 basis points per annum compared to pre GFC levels of a little over 40 basis points per annum)[98]. It is unclear whether large scale interest rate swap transactions at this time would have been possible let alone prudent.

[96] Nominated at the time of a regulatory proposal

[97] This risk was recognised by the AER during its rate of return guidelines process. See AER, *Explanatory Statement, Rate of Return Guideline*, December 2013, p. 104.

[98] CEG, *WACC estimates, a report for NSW DNSPs*, May 2014

Essential Energy's benchmark debt portfolio is estimated to be approximately $6.8 billion by 30 June 2014 (for standard control services alone) and it remains costly and imprudent for us to attempt to match our actual debt costs with the regulatory allowance under a short term averaging period and transition approach. Confidential advice received from UBS that is attached to the regulatory proposal, and which has been previously provided to the AER, outlines that given the depth of the interest rate derivative market there is a real risk that we would not be able to hedge the cost of debt allowance using interest rate swaps. The UBS advice also demonstrates that even if we were able to refinance our entire debt portfolio over a short term averaging period, or use interest rate swaps to match our 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 Essential Energy.[99]

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 Essential Energy's. We therefore support the adoption of the trailing average approach to estimating the return on debt.

Transitional arrangements for the cost of debt

In its final rate of return guideline, the AER stated that the return on debt will be estimated using a ten year trailing average debt portfolio approach[100] after a transitional period. The AER's final rate of return guideline proposes to apply a transition to the trailing average approach to all DNSPs. We agree with the adoption of a ten 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 NEO, and is inconsistent with the RPP 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 DNSPs, including Essential Energy[101].

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 either the AER in making a distribution determination, nor 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 return guideline are elaborated on by CEG in its report titled 'Debt transition consistent with the NER and NEL'. CEG's report is attached to the regulatory proposal.

Inconsistency with the RPP

The RPP set out in section 7A of the NEL provide that a DNSP should be provided with a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control network services, and complying with a regulatory obligation or requirement, or making a regulatory payment. [102]

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[99] UBS, *Advice to Networks NSW*, October 2013 [Confidential]

[100] 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, p73

[101] 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.

[102] 7A(2) of the NEL.

Section 7A sets out the RPP 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.*

…

(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 RPP 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 (the current debt structure) of DNSPs. This means that it is not relevant that some DNSPs 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 DNSPs has the effect that some DNSPs, including Essential 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 2014-19 regulatory control period (2014-15) based on observations of corporate bond yields over a prospective, short term averaging period that is close to the time of their final network determination. For the second regulatory year (2015-16), 90 per cent weight would be given to the observed cost of debt over 2014-15 and thereafter each year the initial observation would be given ten per cent less weight and each new year of data would be given ten per cent 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 ten per cent weighting in the trailing average calculation.

This approach exposes Essential Energy to significant risk because only a small fraction, less than ten per cent, of a benchmark efficient DNSP's debt portfolio (and indeed less than ten per cent of Essential Energy's total debt portfolio) will be refinanced between January and December 2013, in the lead up to 2014-15. Even less would be refinanced over a 20 business day period. Consequently, debt market conditions in this period will affect less than ten per cent of Essential Energy's debt portfolio for a period of around ten years. By contrast, the AER's transition allowance will give this same period 100 per cent weight in 2014-15 and 90 per cent weight in the next year and so on until this period drops out of the AER's cost of debt allowance in ten years. The effect of this is that over the next ten years, this period will have 55 per cent weight in the AER's allowance. This is even more than the 50 per cent weight that the same period would have been given under the previous approach (100 per cent weight in the first of two averaging periods over ten years and zero per cent weight in the second). In this sense, over the next ten years, the AER transition actually compounds rather than alleviates the mismatch problems associated with the former on the day approach.

This exposes Essential 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 Essential 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 Essential Energy, each individual month receives less than one per cent 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[103].

The AER's transition approach means that DNSPs, including Essential 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 distribution determination) may have the effect of denying Essential Energy and others a reasonable opportunity to recover their efficient financing costs, contrary to the RPP. We note that the opportunity to recover costs has been recognised as a crucial factor in the achievement of the NEO (see the Australian Competition Tribunal's decision in EnergyAustralia and Others [2009] referred to below).

In addition, the transition mechanism actively encourages Essential 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, Essential 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 concluded that these swap and hedge contracts were inefficient. Encouraging Essential 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 Essential 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 we may earn (and the charges that we may bill). The potential consequences of under investment in Essential Energy's distribution network are significant given security of supply risks and the importance of electricity supply to customers. Having regard to these issues as required by sections 7A(6) and (7) of the NEL, emphasises the need for Essential 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 NEO

The NEL sets out that the AER must perform or exercise an AER economic regulatory function or power in a manner that will or is likely to contribute to the achievement of the NEO.[104] The NEO 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.

[103] AER, *Explanatory statement, Final rate of return guideline*, December 2013, p. 110.
[104] S 16 of the NEL.

Imposing transitional arrangements which do not allow DNSPs the opportunity to recover their efficient costs and potentially dampens incentives to invest is contrary to the NEO. The Australian Competition Tribunal (ACT) has considered the importance of a DNSP 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 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.*
>
> *…*
>
> *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 (eg. by making insufficient provision for its operating costs or its cost of capital), then the NSP will not have the incentives to achieve the efficiency objectives, the achievement of which is the purpose of the regulatory regime.*[105]

It is evident that the ACT considers that providing DNSPs with the opportunity to recover efficient costs is crucial to 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 Essential 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 Essential Energy. As a result the application of the transition would be contrary to the NEO.

Further, we consider that the transitional approach does not encourage efficient investment practices because it prescribes a rate of return that is likely to penalise those DNSPs 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

Clause 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].*[106]

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. Essential 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.

[105] Application by EnergyAustralia and Others [2009] ACompT 8 (12 November 2009) (EnergyAustralia and Others), [18].

[106] Clause 6.5.2(c) of the NER

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 ten year trailing average approach to determining the cost of debt, which the AER themselves have 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:

> *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.* [107]

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 Essential Energy nor its customers would be subject to adverse outcomes by moving to the ten year trailing average approach. This has been noted in consumer advocacy group submissions to the AER[108]. 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?*[109]

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 ten years by issuing debt on a staggered portfolio basis. Essential 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 DNSPs that were able to refinance 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 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 per cent of all debt in such a narrow window[110]. 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[111].[emphasis added]*

---

107 AER, *Explanatory statement, Final rate of return guideline*, December 2013.

108 See summary of consumer group submissions in NNSW, *Submission to AER draft guideline*, 11 October 2013, p8.

109 EUAA, *Submission on rate of return consultation paper*, p15.

110 This is, of course, borne out by the fact that the AER moved away from an allowance that was based on 100 per cent debt refinancing at the beginning of the regulatory control period. It is also consistent with other statements made in the December explanatory statement to the final rate of return guideline 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*" (p109). For an Australian efficient operator there is no market to effectively, and in a cost efficient manner, hedge their DRP. (p105)

111 AER, *Explanatory Statement, Rate of Return guideline*, 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 control 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, Essential 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 Essential Energy would not be able to hedge all of its debt. The transition proposed by the AER in the rate of return guideline 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 Essential Energy. A transition based on this benchmark efficient entity cannot result in an estimate of the return on debt when it is applied to Essential Energy, particularly one that is exposed to the risks faced by Essential 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, clause 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.*[112]

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 RPP, 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 Essential 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 per cent 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 debt risk premium (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.*
>
> *Therefore the benchmark efficient entity would not be 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*

[112] Clause 6.5.2(k)(1) and (4) of the NER

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[113].

Therefore, even if one did accept that the AER's proposition that *"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 Essential Energy's efficient financing costs in its last distribution determination. Essential 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 our 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 NSW DNSPs that the costs of engaging in interest rate swap transactions were not taken into account when setting benchmark efficient debt costs[114].

In any event, the risks that are faced by Essential 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 ten year BBB corporate bonds (extrapolated to ten years and annualised), the AER's transitional approach to setting the cost of debt would significantly under compensate Essential Energy relative to its stand-alone benchmark efficient costs of debt as illustrated in Tables 7-3 and 7-4. 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 RPP outlined in section 7A of the NEL.

Table 7-3: Essential Energy's benchmark efficient debt cost v AER transition 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 ten years effective term to maturity and annualising), and that rates continue to remain at current levels.

Table 7-4: Essential Energy's potential under-compensation ($nominal, millions)

	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Benchmark debt portfolio	4.062	4,346	4,608	4,874	5,137	
Under-compensation	43	46	49	52	55	244

Note: Benchmark debt portfolio assumes 60 per cent gearing on Essential Energy's forecast RAB over the 2014-19 regulatory control 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 Essential 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. 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.

[113] AER, *Explanatory Statement, Rate of Return guideline*, Dec 2013, p105. The first sentence in this extract is a quote from the AER's adviser, Chairmont consulting.

[114] AER, *NSW DNSPs final decision, 2009-14 distribution determinations*, May 2014, p232.

Clauses 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 ten 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 itself has recognised 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 Essential 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 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 of a 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 purposes of the transition is incorrect, particularly when taking into account the risks of Essential Energy.

Conclusion on cost of debt transition

Essential Energy has consistently raised debt on a staggered portfolio basis over the past ten 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 Essential Energy to more closely match the efficient costs of servicing debt that we have raised over previous regulatory control periods. Essential Energy would not be advantaged or disadvantaged by an immediate transition to a trailing average cost of debt allowance. The allowance would simply more closely match Essential 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 the AER's proposed transitional approach to setting the cost of debt for Essential Energy is inconsistent with the rules and the NEL. We submit that only the ten year trailing average approach, with no transition, meets the rate of return objective and other requirements of the NER. It is also the only approach that allows Essential Energy to recover at least its efficient costs of debt incurred in providing standard control services.

Essential Energy's detailed method and calculations for the cost of debt are outlined in Attachment 7.1.

Automatic update of the cost of debt

Clause 6.5.2(i)(2) of the rules allows 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. Essential Energy agrees with annually updating the allowed return on debt.

Clause 6.5.2(l) of the rules requires that, where the allowed return on debt is different across regulatory years within a regulatory control period, that this be affected through an automatic update. In Attachment 9.2 we set out our proposed approach to adjusting the maximum allowed revenue within the regulatory control period to take into account an annual update the cost of debt. Below we outline how the allowed return on debt itself is estimated for each regulatory year over the 2014-19 regulatory control period.

Essential 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 advises that the methodology used by the RBA is robust and reliable[115]. In its report, CEG also outlines how the RBA BBB forecast of the cost of debt using a ten year target tenor can be annualised and converted to an effective tenor of ten years[116]. This is what is required to obtain an estimate of the ten year cost of the BBB cost of debt for a benchmark efficient energy network firm for each year within the trailing average sample.

Essential Energy considers that the averaging period for each annual observation in the ten year trailing average should use as many data points as possible to minimise 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[117]. 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 ten 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 PTRM. The AER's PTRM requires input of benchmark efficient debt raising costs in basis points per annum (bppa) that is then applied to the RAB[118].

Incenta has researched market data on debt raising transaction costs and has found that benchmark efficient debt raising costs for Australian corporate entities incorporate the following:

- 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 (this was the case during the global financial crisis, European sovereign debt crisis and the US government debt ceiling crisis); and
- costs of refinancing debt 3 months ahead of the refinancing date, which is required by S&P as a condition of maintaining investment grade credit rating.[119]

Overall Incenta found that the benchmark efficient debt raising costs for Essential Energy would be approximately 21.9 bppa on a levelised basis over the 2014-19 regulatory control period. The components of these total debt raising costs are outlined in Table 7-5. Of these benchmark efficient debt raising costs, Essential Energy proposes only to include the debt raising transaction cost component which is approximately 9.9bppa.

[115] CEG, *WACC estimates, a report for NSW DNSPs*, May 2014.
[116] CEG, *WACC estimates, a report for NSW DNSPs*, May 2014.
[117] NSW DNSPs, Letter to the AER on cost of debt averaging periods, 25 February 2014.
[118] AER, *Electricity distribution network service providers: Post-tax revenue model handbook*, June 2008, pp8-9.
[119] Incenta, *Debt raising transaction costs – Essential Energy*, May 2014.

Table 7-5: Essential Energy's benchmark efficient debt raising costs

Debt raising cost component	Levelised cost over the 2014-19 regulatory control period
Debt raising transaction costs	9.9 bppa
Liquidity – commitment fee	6.1 bppa
3 month ahead financing	6.0 bppa
Total debt raising transaction costs	21.9 bppa

Source: Incenta, *Debt raising transaction costs – Essential Energy*, May 2014.

Cost of equity

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 CAPM (SL CAPM), with:

> evidence from the Black CAPM framework informing the estimate of equity beta in the SL CAPM
> evidence from the DGM framework informing the estimate of market risk premium in the SL CAPM
> no evidence to be considered from the FFM.

The guideline also outlines 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 ten year Commonwealth Government bond securities (ten 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 reasonably comparable to the benchmark efficient firm (which it states provides an equity beta estimate range of 0.4 to 0.7)
> 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, DGM 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, takeover/valuation reports, and comparison with the return on debt[120].

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 (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[121] is one important, but far from the only, contribution to this literature);
> evidence from the DGM (estimates of the benchmark return on equity and the return on the market);
> using yields on ten 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; and
> estimates of the MRP using historical excess returns.

[120] AER, *Final rate of return guideline*, December 2013, pp11-17
[121] Black & Fischer, *Capital market equilibrium with restricted borrowing*, Journal of Business 45, 1972, pp444-454

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 FFM. For this reason, the approach specified in the rate of 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[122].

In the context of clause 6.5.2 of the rules 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[123]. 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, Essential 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.

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[124]. 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, as required by clause 6.5.2(e)(3) of the NER.

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 the following areas, as we believe the AER's approach 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 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; and
- 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, and explain our reasons for departing from particular aspects of the AER's method for setting the allowed return on equity.

[122] *Project Blue Sky Inc v Australian Broadcasting Authority* (1998) 194 CLR 355
[123] See pages 23 and 24 of the AER ROR Explanatory Statement
[124] AER, *Explanatory Statement to Final Rate of Return Guideline*, December 2013, Appendices p108

In contrast, the AER's proposed approach is unlikely to achieve the rate of return objective and may not allow Essential Energy to recover at least its efficient costs of equity finance.

Essential Energy's proposed approach to the cost of equity

Essential Energy has assessed all relevant financial models, market data and other evidence as required by clause 6.5.2(e)(1) of the NER to determine that the benchmark efficient cost of equity is in the range of 10.11 per cent to 11.5 per cent. 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 FFM and the 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) of the rules, and the weight that the AER should attribute to them in determining the cost of equity.

Table 7-6 outlines the reasonable range of cost of equity estimates that we have considered to determine our proposed cost of equity.

Table 7-6: Reasonable range for the cost of equity[125]

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%
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	10.9 – 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%

* "low beta bias" is the bias associated with using government bonds as the proxy risk free rate 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, Essential Energy proposes a 10.11 per cent 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 Essential Energy[126]. 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 Essential 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 5.2(e)(1) of the NER. The parameter estimates we have used to estimate the 10.11 per cent minimum required return on equity within the SL CAPM framework are outlined below:

> Rf – a nominal risk-free rate of 4.78 per cent based on historic yields on ten year Commonwealth Government bonds using data from 1883 to 2011, consistent with the dataset underpinning the calculation of the MRP[127].
> MRP – a MRP of 6.5 per cent, based on long-term historic data (1883 to 2011)[128] and consistent with the recommended position contained in the AER rate of return guideline.

125 CEG, *WACC estimates, a report for NSW DNSPs*, May 2014, table 8 and section 2.8
126 As required by clause 6.5.2(c) of the NER
127 CEG, WACC estimates, A report for NSW DNSPs, May 2014.
128 NERA, *The market, size and value premiums*, June 2013, p17.

> βe – an equity beta of 0.82, consistent with the best empirical estimate from SFG which incorporates data from Australian listed energy network firms and US comparator firms[129], drawing on evidence from CEG[130]. This estimate is informed by the empirical approaches suggested by a number of Australian academics[131].

Our proposed SL CAPM point estimate for the allowed return on equity is summarised in the Table 7-7.

Table 7-7: 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, βe	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%**

Source: See summary provided in CEG, *WACC estimates, a report for NSW DNSPs*, May 2014

A detailed description of the approach and calculations of Essential Energy's proposed return on equity is provided in Attachment 7.1.

In terms of equity beta, the AER's small sample of publicly listed Australian energy network firms (currently only five firms out of the sample remain) produces equity beta estimates between 0.4 – 0.7[132]. 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[133]. 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[134] 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.

The AER's final rate of return guideline proposes to estimate the risk free rate using only short term observations of the ten year CGS[135], but to give greatest consideration to historical averages in estimating the MRP[136]. This is an inconsistent approach to populating the SL CAPM in estimating a required return on equity. This is demonstrated by the SL CAPM equation itself. The SL CAPM is specified as outlined in 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 = MRP) having most regard to the historical average market returns in excess of historical average risk free rates

(3) The AER then implements the equation in (1) by combining the MRP estimated in (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)

[129] SFG, *Equity beta*, May 2014, p41 and SFG, *Regression based estimates of risk parameters for the benchmark firm*, p16.
[130] CEG, *Information on equity beta from US companies*, June 2013 and CEG, *AER equity beta issues paper: International comparators*, October 2013.
[131] 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.
[132] AER, *Explanatory statement to the final rate of return guidelines*, December 2013, p86
[133] Henry O., *Estimating beta: an update*, April 2014, p63.
[134] See CEG, *Information on equity beta from US companies*, June 2013, SFG, *Report on equity beta*, May 2014, p15, and SFG, *Regression based estimates of risk parameters for the benchmark firm*, June 2013.
[135] AER, *Final rate of return guideline,* December 2013, p. 15.
[136] AER, *Explanatory statement to final rate of return guideline*, December 2013, p. 95.

However, fundamentally, the MRP is defined in the CAPM as the expected return to the market portfolio less the risk free rate[137]. As a result, whatever risk free rate is used to estimate the MRP must be the same as the risk free rate separately input as the first term on the right hand side of step (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 step (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 specifically stated that such interrelationships of parameter values be recognised[138].

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 per cent. We note that NERA economic consulting has produced the most recent and comprehensive estimate of historical excess returns of 6.5 per cent for the period 1883 to 2011[139]. 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 ten 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 MRP estimate. The only ways to avoid inconsistency between the risk free rate estimate used by the AER and the historically estimated MRP are to either:

(1) estimate the risk free rate as the average yield on ten year CGS over the period 1883-2011 as we propose; or
(2) estimate the risk free rate using short-term observations of yields on ten year CGS and estimate the MRP 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 outcomes in terms of electricity charges for our customers between regulatory control 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 per cent. We also note that, as shown above, option 2 gives very similar estimates – also centred on 10.1 per cent (CEG has estimated 10.1 per cent and SFG base estimates are 10.2 per cent).

[137] CEG, *Estimating the Return on the Market*, June 2013, p4
[138] AEMC, *Draft Rule Determinations Draft National Electricity Amendment (Economic Regulation of Network Providers) 2012*, 23 August 2013, p50.
[139] NERA, *The market, size and value premiums*, June 2013, p17

SFG has estimated that the prevailing expected return on the market is around 10.32 per cent excluding any value for imputation credits[140]. SFG has estimated a risk free rate of 4.12 per cent over the 20 days ending on 14 February 2014. This implies a MRP excluding the value of imputation credits of 6.2 per cent. Applying an equity beta of 0.82 gives a DGM estimate of the required return on equity before imputation credits of 9.2 per cent (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 per cent.

CEG has similarly estimated that the prevailing expected return on the market is around 11.4 per cent including the value for imputation credits. CEG has estimated a risk free rate of 4.0 per cent over the 20 days ending on 13 May 2014. This implies a MRP including the value of imputation credits of 7.41 per cent. Applying an equity beta of 0.82 gives a DGM estimate of the required return on equity inclusive of the value of imputation credits of 10.0 per cent (=4.0% + 0.82 * (11.4% - 4.0%)).

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 MRP based on historical excess returns on equity[141]). 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 (ten 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[142].

CEG has estimated that the historical average return on the market in Australia (normalised to a 2.5 per cent inflation environment) is 11.56 per cent. Over the 20 trading days ending on 13 May 2014, average yield on ten year CGS is 4.0 per cent, implying an MRP of around 7.4 per cent. With an equity beta of 0.82 the Wright approach delivers an estimate of the cost of equity of 10.2 per cent (4.0% + 0.82 * (11.6% - 4.0%))[143]. 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 per cent prevailing risk free rate with a historical average MRP estimate of 6.5 per cent and an equity beta of 0.82 per cent will result in a cost of equity estimate of 9.3 per cent. This is substantially lower than Essential Energy's proposed cost of equity, which is itself lower than 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 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)[144]. CEG has advised that the Wright approach should also be used to check whether 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 of combining 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[145].

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140 SFG, *Alternative versions of the dividend discount model and the implied cost of equity*, May 2014, p59.

141 Wright S, ***Response to Professor Lally's Analysis***, November 2012, p5.

142 CEG, *Estimating the Return on the Market*, June 2013, pp30-31.

143 CEG, *WACC estimates, a report for NSW DNSPs*, May 2014.

144 Conclusion vii in Wright S., ***Response to Professor Lally's Analysis***, November 2012, p3.

145 CEG, *WACC estimates, a report for NSW DNSPs*, May 2014.

This highlights the significant internal inconsistency in the AER's approach to parameterising the SL CAPM, which is discussed above.

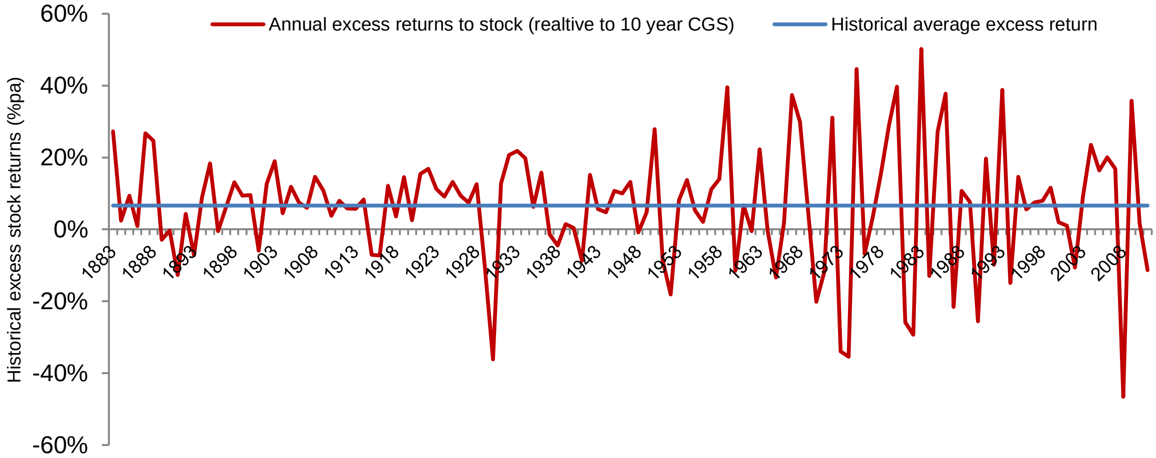
Having regard to prevailing market conditions

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 the internally consistent SL CAPM parameters above. This provides a cost of equity estimate of 10.1 per cent (averaging CEG and SFG based estimates) which is very similar to our proposed 10.11 per cent 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 per cent. 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 the 2014-19 regulatory control period.

There is also an advantage to using historical data as it can help to smooth out short term volatility in financial market data. For example, when estimating historical excess returns, the annual data relied on by both the AER and Essential Energy shows significant variation over the estimation period, as illustrated in Figure 7-3. However, averaging this data (as per the blue line in Figure 7-3) using a long term approach would promote stability in allowed equity returns across energy network determinations.

Figure 7-3: Historical realised excess returns on the market



Source: CEG, *WACC estimates, a report for 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[146]. 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 estimates 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 rules when

[146] AEMC, *Final Rule Determinations Draft National Electricity Amendment (Economic Regulation of Network Providers) 2012*, 29 November 2012, p66.

assessing the available information. In particular, the allowed return on equity must be estimated such that it is consistent with the allowed rate of return objective (clause 6.5.2(f) of the NER).

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, Essential 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 rate of return pursuant to clause 6.5.2(e) of the rules. Recent analysis from CEG and SFG illustrates that the Black CAPM framework can be used to provide robust cost of equity estimates for the benchmark energy network firm[147]. 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)[148]. 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 the 2014-19 regulatory control period.

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 Essential 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 Essential 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 our 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[149].

With regard to the second point, the zero beta premium estimates from SFG[150] (and many other academic studies as listed by CEG[151]), 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 and 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 that the AER's implementation of the SL CAPM (using the government bond rate as the risk free rate proxy) is likely to

147 SFG, *Cost of equity in the Black capital asset pricing model*, May 2014.
148 AER, *Explanatory statement to the rate of return guideline*, Appendices, p17.
149 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, pp16-18. 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.
150 SFG, *Cost of equity in the Black capital asset pricing model*, May 2014.
151 CEG, *WACC estimates, a report for NSW DNSPs*, May 2014.

underestimate the required return on equity for stocks with an empirical equity beta less than 1.0[152]. 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 approximately (1 – 0.82) * 0.5 * MRP, which would be 59 basis points for an MRP of 6.5 per cent.

The Fama-French Three Factor Model

The AER's final rate of return guideline gives no weight to the 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 regulatory control period effectively requires a prediction of what equity investors require or 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 regulatory control 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 Essential 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.*[153]

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.*[154]

These statements provide a clear indication that the Nobel Prize Committee considers the FFM model is a relevant financial model for estimating equity returns.

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:

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152 SFG, *Cost of equity in the Black capital asset pricing model*, May 2014; NERA, *Estimates of the zero beta premium*, June 2013 and CEG, *WACC estimates, a report for NSW DNSPs*, May 2014.

153 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

154 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

- 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; and
- 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[155] set out, contrary to the AER's statements in the final rate of return guideline, that:

- 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[156]); and
- the FFM is used in practice[157].

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[158]. CEG has estimated the return on equity for the benchmark efficient energy network firm to be approximately 11.5 per cent using long term estimates of parameters in the FFM and 10.7 per cent 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; and
- information on the required return on equity for a firm facing a similar nature and degree of risk as that faced by Essential Energy 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 Essential 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 per cent 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 Essential 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 NEO, whereas disregarding all evidence from the FFM as proposed in the AER's final rate of return guideline will not.

155 NERA, *The Fama-French Three Factor Model*, October 2013.
156 SFG, *Regression based estimates of risk parameters for the benchmark firm*, June 2013.
157 See NERA, *The Fama-French Three Factor Model*, October 2013, pp34-42.
158 AER, *Explanatory Statement to the Final rate of return guideline*, December 2013, Appendices, p23.

The Dividend Growth Model

The AER's final rate of return guideline recognises that the DGM is a relevant financial model that should be considered when setting the allowed return on equity[159]. 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[160]. 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 enough 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 per cent using data from July 2002 to January 2014 and 7.46 per cent using market data from January 2010 to November 2013[161]). 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[162]. 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 a long run dividend growth rate[163], other than to say that SFG's DGM is complex[164].

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[165]. 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[166]. 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.

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159 AER, *Final rate of return guideline*, December 2013, p13 and AER, *Explanatory statement to the final rate of return guideline*, December 2013, p96

160 AER, *Explanatory statement to the final rate of return guideline*, Appendices, December 2014, pp. 14-15.

161 SFG, *Alternative versions of the Dividend Growth Model*, May 2014, p11.

162 AER, *Final rate of return guideline*, Appendices, December 2014, pp14-15.

163 SFG, *Dividend discount model estimates of the cost of equity*, June 2013.

164 AER, *Final rate of return guideline*, December 2014, pp14-15.

165 SFG, *Dividend discount model estimates of the cost of equity*, June 2013, pp11–16.

166 SFG, *Alternative versions of the Dividend Growth Model*, May 2014, p64.

SFG's report outlines that the required return on equity for the benchmark efficient energy network firm is approximately 11.0 per cent using a DGM based estimate of relative risk for the equity beta (as opposed to a regression based estimate of beta) in the CAPM[167]. 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) 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 of relative risk for the benchmark efficient energy network business reflects prevailing market conditions as required by clause 6.5.2(g) of the rules. 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 (ie. 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 Essential Energy.

We consider that SFG's DGM based estimate of the required return on equity for the benchmark efficient energy network firm (11.0 per cent) indicates that our proposed return on equity of 10.11 per cent 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 Essential 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 NEO, 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 recognise equity raising costs as capital expenditure within the PTRM and amortise these costs over the life of the assets that they are used to fund[168]. Essential 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 of these costs are outlined in Table 7-8.

Table 7-8: Benchmark efficient equity raising costs components

Equity raising cost component	Cost over the 2014-19 regulatory control period
Seasoned equity offering (SEO)/ Subsequent equity raising costs	3.00%
Dividend re-investment plan cost	1.00%

Source: AER, *Powerlink transmission determination 2012-13 to 2016-17*, April 2012, p108

In estimating the benchmark efficient equity raising costs we have assumed a dividend re-investment plan take-up of 30 per cent and a dividend payout ratio of 70 per cent. This is consistent with our assumption on the imputation credit payout ratio, which is discussed further below.

The value of imputation credits

The NER state that the estimated cost of corporate income tax should be reduced by the value of imputation credits. Within the PTRM framework, this means that the allowed revenues for tax expense will be less than the

167 SFG, *Alternative versions of the Dividend Growth Model*, May 2014, p64.

168 See for example AER, *Final decision, ElectraNet transmission determination 2013-14 to 2017-18*, p87; AER, *Final Distribution Determination Aurora Energy Pty Ltd, 2012-13 to 2016-17*, April 2012, p78; AER, *Final decision, Powerlink transmission determination 2012-13 to 2016-17*, April 2012, pp107-108; AER, *Final decision, Victorian distribution determinations 2011-2015*, Appendix O, pp505–506; AER, *Final decision, Qld Distribution determination 2010-11 to 2014-15*, May 2010, p201;

company is actually likely to incur. Most companies pay a cost of corporate income tax equal to 30 per cent of earnings after operating expenditure, interest costs and depreciation. However, under the NER framework, the revenues allowed for the cost of corporate tax are reduced by the assumed value of imputation credits as set out in clause 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 section 7A of the NEL, which requires that:

> *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 per cent. 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.

Essential 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).

Essential 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[169].

Essential Energy proposes a value for theta of 0.35. The reasons why we are proposing a different value for theta to that in the rate of return guideline include:

- Essential 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

169 NERA, *The payout ratio*, June 2013

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 Essential 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. Essential Energy's reasons for proposing a different value for theta to that in the rate of return guideline are outlined in Attachment 7.26 and SFG's latest report addressing the value of imputation credits[170].

[170] SFG, *An appropriate regulatory estimate of gamma*, May 2014

8. ALTERNATIVE CONTROL SERVICES

The AER regulates our public lighting services, ancillary network services and elements of our metering services separately from our standard control services. The AER sets a price cap for these services. Our proposed charges reflect the efficient costs of providing the services.

In this Chapter we set out our proposed charges for those services classified as alternative control services by the AER. These services are considered to be separate from our standard control service, and result in customers getting an individual charge for the service we provide rather than the costs being bundled as part of the network tariff charge. The key points of this Chapter are:

> Our proposed charges 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.
> Our proposed metering charges will be based on the type of meter that a customer has installed on their premise. Customers will have a separate tariff for metering services depending on the meter installed. In developing charges, we have considered the revenue we need to fund significant investment in metering undertaken in the past, as well as ongoing operating costs.
> Our proposed charges for each ancillary network service will reflect the efficient costs of providing that service. We have more than 40 non-routine services we provide to our customers. In the past, the customer only paid a portion of the cost of providing the service, with the residual collected from all other customers through electricity charges. The AER now considers that customers should face the full cost reflective charge for these services.

Public lighting services

Our proposed approach to charging public lighting services is consistent with the 2009-14 regulatory control period. Lights funded by Essential Energy attract a capital charge and all lights attract a maintenance charge. The capital charge on lights installed prior to 2009 is derived from a fixed RAB as determined by the AER. The capital charge on lights installed after 2009 is derived from a building block annuity model.

In this section we identify the method by which we have developed charges for the public lighting services we provide our customers.

About our public lighting services

Public lighting services encompass the maintenance and replacement of public lighting and emerging public lighting technology[171]. Essential Energy provides public lighting services to over 100 customers including councils, community groups and government associations. There are over 150,000 public lights in Essential Energy's network area, which are typically installed on major and minor roadways. A conventional public light comprises three main components of a luminaire, a support structure, and a connection to the low voltage electricity network.

Each luminaire, support structure and connection is treated as an installation from a charging perspective and attracts a capital charge and a maintenance charge. Customers pay both charges where assets are funded by Essential Energy. Where customers choose to fund public lighting assets outright or public lighting assets are gifted to Essential Energy, then the customer only pays for maintenance activities. Additionally, some customers choose to replace an existing public lighting asset before its economic end of life. In this case a residual charge is calculated, representing the remaining value of the asset, and this is then invoiced to the customer.

[171] AER, *Stage 1 Framework and approach paper, Ausgrid, Endeavour Energy and Essential Energy, Transitional regulatory control period 1 July 2014 to 30 June 2015 & Subsequent regulatory control period 1 July 2015 to 30 June 2019*, March 2013.

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 customers. The strategic objectives have been developed through consultation with our customers and the use of the public lighting code dated 1 January 2006. There are five strategic objectives which are described below.

Minimise total lifetime cost for Essential Energy and our customers

The provision of public lighting includes both capital and maintenance charges. In order to provide an efficient service to the customer, we need to consider all charges over the lifetime of assets when selecting technologies.

Furthermore, ensuring that Essential Energy operates prudently and efficiently is fundamental to providing the required service at the lowest cost.

Maintaining network performance as described in the public lighting code

The public lighting code is a document which describes minimum performance standards and practices for the provision of public lighting services. This document references the Australian Standard for public lighting. In the 2014-19 regulatory control period, we expect to continue to meet those targets to achieve excellence in all aspects of the code including:

- improving network reliability
- reducing the spot outage rate
- minimising costs and maintaining service levels.

Method for developing public lighting charges

There are three categories of public lighting charges:

- fixed capital charge for assets installed prior to 2009 with a residual value if replaced early
- annuity capital charge for assets installed post 2009 with a residual value if replaced early
- maintenance charge that is applied to all assets.

Costs of providing public lighting services

There are three main costs in providing public lighting services. These are capital costs, operating costs, and process improvement costs.

- **Capital costs** - these refer to costs relating to the installation of public lighting assets either for new connections, or replacement of assets due to poor performance or obsolescence due to new technology.
- **Operating costs** - these refer to the ongoing costs to maintain and repair the public lighting network.
- **Process improvements** - these involve investing in systems which improve the way the public lighting business is operated, resulting in lower costs or improved service. These have the effect of modifying maintenance charges or improving service levels.

The forecast expenditure for the 2014-19 regulatory control period takes into account the recovery of all costs to fund current and proposed tariffs to comply with the State Owned Corporation's Act as well as the NEL.

Engagement with Public Lighting Customers

Essential Energy has undertaken consultation with its public lighting customers and has received feedback in relation to the complicated nature of the previous tariff structure. To address this, Essential Energy propose to introduce a new tariff structure derived from a componentised tariff model that will make the identification of lights and charges less complicated and transparent.

Essential Energy has informed its customers of the proposed componentised charging model. This has been by way of a circular sent via email to all customer representatives on 10 April 2014. To date we have received various positive responses in regard to the simplification of the model, and will continue to engage with our stakeholders to the extent possible to satisfy our customers' needs.

Developing charges

In order to meaningfully invoice customers, we need to convert the expenditure into charges which reflect the service being provided. The starting point is a basis for control which allows us to construct models to calculate the charge. The inputs to the models are the key to ensuring all costs are accounted for. The proposal, models and charges for public lighting can be found at Attachments 8.1, 8.2 and 8.3 respectively.

Metering services

In the stage 1 F&A, the AER decided to re-classify metering services from standard control to alternative control. This has meant that metering is no longer part of the bundled charge for standard control services, but that customers pay a cost reflective charge based on the meter installed.

In this section we outline our proposed charging for metering services. We identify what meters are subject to regulation by the AER, how we developed charges, and the charge our customers would expect to pay depending on the type of meter installed.

About our metering services

Metering services is one of the terms developed by the AER to group classes of services provided by NSW DNSPs. The AER has divided metering services into three categories:

- **Metering Installation Types 1, 2, 3 and 4 -** The rules require a Type 1, 2, 3 or 4 metering installation at premises where energy consumption is greater than 160MWh per annum[172]. These types of meters record detailed energy usage and have a number of other required capabilities[173], the most significant being the requirement to have remote communication facilities installed.

  The provision of Metering Services for Metering Installation Types 1,2, 3 and 4 is provided in a competitive market and are therefore not regulated by the AER.

  Metering Installation Types 5 and 6 – Type 5 metering installations record energy in 30-minute intervals, without the requirement to remotely acquire the data. Typically, these meters are read every three months, sometimes monthly[174]. Often the term Manually Read Interval Meter (MRIM) is used interchangeably for Type 5 Meter. A Type 5 metering installation however is not the same as a Smart Meter[175] installation. Essential Energy has very few Type 5 meters installed, and these are generally read as Type 6 meters.

  A Type 6 metering installation is defined as a 'general purpose' meter that records accumulated energy data only[176]. The term 'BASIC meter', accumulation meter and Type 6 meter can be used interchangeably.

- **Metering Installation Type 7** - A Type 7 metering installation applies to the condition where it has been determined by the Australian Energy Market Operator (AEMO) that the metering installation does not require a meter. Examples may include, street, traffic, park and community lighting, traffic parking meters.

  The AER has decided that Metering Data Services associated with Type 7 Metering Installations, like Network Services, will continue to form part of Standard Control Services.

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172 An average domestic customer consumers approximately 7MWh pa.

173 Meter capabilities include the ability to record 1/2 hr energy consumption (kWh), data storage requirement >35 days, the measurement of reactive energy (kvarh) (for Type 1, 2 and 3) and the ability to access the meter data on a daily basis (i.e. remote communication facilities).

174 The time between meter reads is normally a function of the network tariff applicable to a customer's premises.

175 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.

176 Processes used to convert the *accumulated metering data* into *trading interval metering data* for settlements purposes are included in the *metrology procedure.*

From 1 July 2014, the AER proposes to separately regulate the metering services associated with Type 5 and 6 metering installations that are provided by NSW DNSPs. These are the services which require a separate charge and are the focus of this section.

There are approximately 0.8 million Type 5 and Type 6 National Metering Identifiers (NMIs) connected to Essential Energy's distribution network. Some NMI's have 1 meter, whilst other NMI's have two or more. This is why the total Type 5 and Type 6 meter population is approximately 1.5 million meters as shown in Table 8-1.

Table 8-1: Essential Energy's type 5 and 6 metering population (2013-14)

Essential Energy's Type 5 and 6 metering population	Totals
Essential Energy NMIs	810,457
Essential Energy Meters	1,466,078

The NER establish the role of the responsible person (RP) as the party responsible for:

- the provision, installation and maintenance of a metering installation
- the provision of Metering Data Services (including the collection, processing and delivery of the metering data) in accordance with the Rules
- engaging appropriately accredited Metering Providers (MPBs) and Meter Data Providers (MDP) to conduct these services on their behalf.

The Local Network Service Provider (LNSP) is mandated under the Rules to perform the role of RP for Type 5 and Type 6 metering installations at premises with energy consumption less than 160 MWh per annum where Type 5 or 6 metering is installed. As the designated RP for Type 5 and 6 metering installations located in Essential Energy's network area, the rules require us to:

- ensure that all relevant connection points are metered to the defined standard
- develop a Metering Asset Management Plan (MAMP) for the maintenance of metering installations and for the MAMP to be approved by the Australian Energy Market Operator (AEMO)
- comply with the Rules and the associated Procedures (Metrology and MP/MDP Service Level Procedures) in relation to the method for provision, installation, maintenance of metering installations and provision of metering data services.

Where relevant, we also ensure that we meet the Australian Standards applicable to metering equipment. Type 5 and 6 metering equipment must also meet the requirements of the National Measurements Act and the equipment is Pattern Approved and verified by a National Measurements Institute approved laboratory.

Strategic objectives of metering services

Essential 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 charging strategies
- able to support the network load control strategy
- able to support any required market or customer objectives.

Method to develop charges for metering services

The AER has specified that a price cap will apply as the control mechanism for metering services. Accordingly we have sought to develop charges for Type 5 and 6 meters that meet the following principles:

> **Facilitates customer choice** – this means providing customers with a realistic purchase cost for meters.
> **Cost reflective** – to enable customers to make informed decisions, charges have been developed that reflect the true costs of providing the service. We have established the charges taking into consideration our historical and forecast expenditure and how these costs are best apportioned to meter types.
> **Equitable** – our charging method aims to eliminate cross subsidisation and provides appropriate signals to customers making decisions regarding their metering services. This will provide customers with appropriate charging arrangements without penalising them for previous decisions. Our approach seeks to write down the value of the existing residual RAB for Type 5 and 6 meters over the next seven years.
> **Administratively simple** – with a commencement date for separate charging for metering services of 1 July 2015, we have taken into account our existing IT and billing capabilities. We have sought to avoid an approach requiring significant implementation costs or costly on-going reporting and reconciliation requirements. Our approach should provide customers with simple, transparent information.

In developing a cost reflective charge, we have examined our historical records to determine what drives our metering costs. A full explanation of our proposal and supporting material can be found in Attachments 8.4, 8.5, and 8.6.

To summarise, as a large proportion of our costs are both fixed and based on actual meters at a NMI level, we have split services between primary and secondary meter services. The latter are metering services that are in addition to the primary network service most customers receive, and include services such as off-peak hot water or solar PV metering. These additional services result in marginally higher overall costs and therefore attract a lower incremental charge.

A customer will pay a greater amount for their primary 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 whilst providing a fair and appropriate charge for the service a customer is receiving.

Costs to deliver Type 5 and 6 Metering Services

The delivery of Type 5 and 6 metering services require both operating and capital expenditure. In addition to the capital costs of meters on an ongoing basis, capital costs also relate to the return on and return of the meter RAB that existed prior to 1 July 2014. These costs are detailed in the sections below.

Operating costs

The total operating costs for metering services include costs for maintenance, meter reading and meter data services. The total forecast operating costs of providing metering services for the 2015-19 regulatory control period is $103.5 million as shown in Table 8-2. These costs will be recovered by a cents per day charge.

Table 8-2: Annual operating expenditure for Type 5 and 6 metering services[177] ($million, 2013-14)

Operating expenditure	2015-16	2016-17	2017-18	2018-19
Meter Maintenance	4.33	4.42	4.50	4.65
Meter Reading	18.83	19.10	19.48	19.78
Meter Data Services	2.07	2.07	2.12	2.15
Total	25.22	25.58	26.10	26.58

[177] Excludes debt raising costs

Total capital expenditure is forecast to be $56.4 million for the 2015-19 regulatory control period. The annual forecast capital expenditure is shown in Table 8-3.

Table 8-3: Annual capital expenditure for Type 5 and 6 metering services[178] ($ million, 2013-14)

Capital expenditure	2015/16	2016/17	2017/18	2018/19
Replacement	7.85	8.23	11.41	11.37
Growth	3.34	7.07	3.61	3.54
Total	**11.19**	**15.30**	**15.02**	**14.90**

The costs associated with replacement capital will be recovered via a cents per day charge along with operating costs. However new (growth) meters will be funded upfront by the customer. 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 in line with our existing practice for non-standard meters and will be extended to standard meters from 1 July 2015. Charges for these meters are detailed in Attachment 8.7.

Indicative charges

The NER require us to provide indicative charges for Type 5 and 6 metering services. These indicative charges are provided in Attachment 8.7. In Attachment 8.4, we outline the charging method we have adopted to establish these charges.

We are also proposing an exit fee for circumstances where a customer chooses to upgrade the meter at their premises (that is currently managed and maintained by Essential Energy) to a Type 1, 2, 3 or 4 meter. This fee is to cover the 'sunk' or stranded costs associated with our past investment. In choosing to propose exit fees and in developing those charges we have noted the recommendations in the AEMC's Power of Choice Review (Stage 3) published in November 2012 regarding exit fees. Our considerations in this regard are outlined in Attachment 8.4, and the proposed exit fees can be found at Attachment 8.7.

Ancillary Network Services

In this section we explain what ancillary network services are and the methodology we have used to set charges for these services. Attachments 8.8 and 8.9 provide further information on the activities undertaken to provide each ancillary network service and their costs.

What are 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 needs basis. Examples include providing design-related information for connections to our network, special meter readings and site establishment fees.

These services are currently called miscellaneous and monopoly services and form part of standard control services provided by NSW DNSPs. The charges for these services were first set in 1999.

From 1 July 2014, some new services will commence such as those that are required to satisfy the National Energy Customer Framework (NECF) requirements. The AER is also proposing to reclassify these services to alternative control services from 1 July 2014 because the costs of such services can be directly attributed to an individual or small group of customers.

Charges for many of the existing services were originally set by IPART in our 1999 Determination. Since that time, charges have only been indexed with inflation every five years and not reviewed in detail. As such, many of these services have not been cost reflective, with the extra costs subsidised by all customers using standard control

[178] Excludes equity raising costs

services through tariff charges. This change in classification recognises this issue, and seeks to ensure that standard control services customers do not subsidise activities specific to a small sub-set of customers.

While in general, the charges associated with ancillary network services will increase to more accurately reflect costs, the increases in charges are generally a result of removing costs that historically have been allocated to the provision of other services by Essential Energy (i.e. we have sought to remove cross subsidies and achieve charges that reflect actual costs). A corresponding decrease in costs from Essential Energy's standard control services has occurred.

From 1 July 2014, there will be additional service groups. However within some groups there are multiple services and charges. The list of service groups and services is provided in Attachment 8.9.

In this section we outline our proposed charges for ancillary network services. We identify what services are subject to regulation by the AER, how we developed charges, and the charge our customers would expect to pay depending on the service used.

Activities undertaken to deliver Ancillary Network Services

We provide in Attachment 8.9 a workbook for every service group. The workbook outlines the AER's current service description, any additional service-related information, a description of what is involved in providing the service and the current and proposed charge. For new ancillary network services, and for some existing services where Essential Energy considers that the scope of the activity has changed or evolved, we also provide a more detailed task breakdown and the relevant skill level required to perform the activities within each task.

Method used to develop charges

The AER has stated it will set service specific charges to enable the distributor to "*recover the full cost of each service from customers using that service*" and by doing so ensure that standard control customers do not subsidise these services required by specific customers. As these costs historically have been included in standard control services, detailed historical costs are not available. Therefore the cost of each service, whether existing or new, has been developed on a bottom up basis, based on the time taken to complete each task along with other resources required.

Method to determine costs

In most cases, this historical data is not available or is not at a sufficient level of detail to determine the historical costs of service components. We explain the reasons for this in the associated worksheet models (included in Attachment 8.9). In those circumstances and for the new services, we have developed an estimate of hours and costs based on a bottom-up forecasting process. This has resulted in Essential Energy using one of three methods to determine the costs to provide the services and establish charges as follows:

> **Historical data** - For a small number of existing services, we are able to identify incurred costs associated with the provision of the services, the numbers of services that historically have been provided and the hours associated with provision of the services. For those services, we have typically used three years of historical data to determine the cost of the service and establish the charge, unless there is a compelling reason to use only 2012-13 Figures.

> **Operating costs** - This method uses available data to establish an average cost to provide the service. In these instances, we are able to identify incurred costs associated with the provision of the services and the number of services that have historically been provided. For some services, the historic costs have not been recorded on a service-by service level and we have apportioned historic costs between some services.

> **Bottom-up approach** - For those services where we were unable to reliably extract the data, a bottom-up approach was used. This was particularly the case for new ancillary network services that we do not currently bill for. In these instances, the type of employee who carried out the service was identified with an average hourly rate and an estimate of the time it took to carry out that service, including travel time and fleet or other resources used to perform the task. These direct unit rates were then used to calculate the costs of the applicable ancillary network service.

Forecast volumes of works

Our volumes of service provision were calculated in one of two ways. First where available, data was extracted from our IT systems that are currently used for invoicing the current miscellaneous and monopoly fees. In other cases the volumes were derived from work orders issued to perform a service. In both cases volumes were based on the average of three years of historical data adjusted for growth (if applicable). If there has been a significant increase or decrease in the number of services in the proceeding period, forecasts have been based on volumes for the last 12 months. For new fees the volumes were derived based on our best estimates.

Please refer to Attachment 8.10 for a listing of our charges and forecast volumes per service. In addition an independent review of the models used to develop charges for these services was undertaken by KPMG and this report is included as an appendix to Attachment 8.8.

Indicative charges for ancillary network services

Attachment 8.10 sets out our indicative charges for ancillary network services.

Compliance with control mechanism and basis of control

The AER has decided to apply caps on the charges of individual services to all alternative control services for the 2014-19 regulatory control period[179]. The AER also set out its proposed formulae that give effect to the control mechanism[180]. As stated in Chapter 3, Essential Energy adopts the AER's approach to the proposed formulae and considers that the demonstration of compliance with the control formulae for alternative control services will be done through the annual pricing proposal process, using the published lists of charges as the vehicle to demonstrate compliance.

Clause 6.2.6(b) of the rules provides that, for alternative control services, the control mechanism must have a basis stated in the distribution determination and that the basis of control may use elements of Part C of the rules. Part C of the rules outlines the building block approach for standard control services.

In deriving charges for alternative control services so that we can demonstrate compliance with the control mechanism, Essential Energy has adopted a cost build-up approach to the setting of these charges, an approach that is analogous to the building block approach prescribed for standard control services.

As noted in Chapter 4 above, Essential Energy considers that the pass through provisions in the rules should apply to alternative control services, and should form part of the basis of control to be determined by the AER. As we have utilised an approach to the setting of charges that is similar to the building block approach, we consider the costs of providing alternative control services can be adjusted to account for the cost impact of pass through events that have materialised (after having been subjected to the pass through assessment process by the AER under clause 6.61 of the rules).

True-up for the transitional year

The NSW DNSPs requested that the AER specify in the stage 2 F&A how a true-up of charges will be made for alternative control services. In the stage 2 F&A the AER noted that given that it is yet to see how Essential Energy intended to treat alternative control services charging in their transitional regulatory proposals, it preferred not to prejudice whether, and if so, how alternative control services charges are to be trued-up.

For this reason, it did not specify the exact manner in which alternative control services charges may be adjusted in the stage 2 F&A. Instead the AER stated that it will examine options for a true up as part of the regulatory review and provide reasons for the approach that is eventually adopted in its distribution determination[181].

[179] Stage 1 F&A, p57
[180] Stage 1 F&A, pp60-62
[181] Stage 2 F&A, p40

As we have noted to the AER previously[182], Essential Energy considers that a true up mechanism for alternative control services should be implemented so that the AER can exercise its power in accordance with the NEO and the RPP of ensuring the long-term interest of customers in respect of charges, and of ensuring the DNSPs are given a reasonable opportunity to recover their efficient costs[183].

In particular, as previously agreed with the AER, the recovery of revenue for alternative control services that were previously classified as standard control services was to be recovered through charges for standard control services during the transitional year but not in subsequent years. However, this amount has not been included in the proposed annual revenue requirements for the 2014-19 regulatory control period in this regulatory proposal as we have assumed that:

a) as standard control services revenue should only be for standard control services, a "pure" amount should be provided for the purposes of determining the five year revenue amounts (i.e. not inclusive of revenue recovered through the transitional year for alternative control services);

b) as the AER has previously agreed to the recovery of reclassified alternative control services revenue for the transitional year through DUOS charges, that this position is unchanged and this approach will continue to apply; and

c) any shortfall in revenue for alternative control services for the transitional year will be recovered through prices for alternative control services in the subsequent years through a true up mechanism.

We set out our view on how a true up mechanism may operate for the AER's consideration in Attachment 8.11.

[182] See letter of 10 January 2014 to the AER's chairman, from the Chief Executive Officer of Ausgrid, Endeavour Energy and Essential Energy

[183] As per letter of 10 January 2014 to the AER's chairman, from the Chief Executive Officer of Ausgrid, Endeavour Energy and Essential Energy.

9. PRICING ARRANGEMENTS

The purpose of this Chapter is to identify our approach on tariff design for the 2014-19 regulatory control period, and the reporting arrangements for our annual pricing proposal.

Our network tariffs account for approximately 40 to 50 per cent 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 regulatory control period, 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 for Type 5 and 6 meters, noting that the charge a customer pays will depend on the meter installed.
- **Jurisdictional scheme amounts** – these amounts allow us to recover our annual contribution to the NSW climate change fund and Queensland solar scheme.
- **Designated pricing proposal charges -** these predominately relate to payments we make to TransGrid for the use of its transmission network in NSW[184].

How we set our network tariffs

The integrated nature of electricity means that we cannot establish a unique 'cost reflective' charge 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 premise. For instance, interval meters enable us to charge customers depending on the time they use electricity (time of use charging).

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:

- **Revenue sufficiency** – this means that our network tariffs recover sufficient revenue to fund the efficient cost of owning, operating and investing in our distribution network. It also means that we pass through to our customers the full cost associated with our use of the transmission network and our annual contributions to the NSW climate change fund and Queensland solar scheme.
- **Equity -** this means that customers pay charges 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 charges depending on whether energy is used at peak or off peak times. This has the benefit of reducing peak demand and avoiding the need to undertake capacity investment.

Proposed tariff classes

In developing our network tariffs for the annual pricing proposal, we are required by the rules to assign customers to an individual tariff class. This is an important aspect to our annual setting of charges because we must demonstrate that we comply with the pricing principles in the rules at the tariff class level, rather than individual tariff level.

[184] 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.

We believe that our current tariff classes are appropriate for the 2014-19 regulatory control period because they result in customers being grouped together in a way that is economically efficient and do not impose unnecessary transaction costs on Essential Energy or our customers. Our current tariff classes are summarised in Figure 9-1 below.

Tariff class	Tariff code	Tariff name
Low Voltage - Energy	BLNN2AU	LV Residential Continuous
	BLNC1AU	LV Controlled Load 1
	BLNC2AU	LV Controlled Load 2
	BLNT3AU	LV Residential TOU
	BLNN1AU	LV General supply
	BLNT1AO	LV TOU over 100 MWh/yr
	BLNT2AU	LV TOU 0 - 100MWh Cent Urban
Low Voltage - Demand	BLND1CO	LV 1 Rate Dmd Cent
	BLND1SR	LV 1 Rate Dmd Sth Rural
	BLND1SU	LV 1 Rate Dmd Sth Urban
	TLD	Time of Day - LV Demand - FW
	BLND3AO	LV TOU Demand 3 Rate
	BLND4NO	LV 3 Rate Dmd Option 2 Nth U
	BLNS1AO	LV TOU avg daily Demand
	BLND3TO	LV TOU Demand-alternate tariff
High Voltage	BHND1CO	HV 1 Rate Dmd Cent U
	BHND1SO	HV 1 Rate Dmd Sth U
	BHND3AO	HV TOU mthly Demand
	BHNS1AO	HV TOU avg daily Demand
Sub-Transmission Voltage	BSSD3AO	Sub Trans 3 Rate Demand
	Cost Reflective Network Price	Individually calculated - site specific
Unmetered	BLNP1AO	LV Public Lighting NUOS
	BLNP3AO	LV Public Lighting TOU NUOS

Figure 9-1: Proposed tariff classes for the 2014-19 regulatory control period

For further detail on tariff classes, service categories and tariff components refer to Attachment 9.5.

Indicative Charges and Tariffs

The tariffs that apply from 1 July each year are determined through our annual pricing proposal process. However, the rules require us to provide indicative charges as part of our regulatory proposal. Our indicative charges for the 2014-2019 regulatory control period are set out in Chapter 4.

Proposed procedures for assigning existing and new customers to tariff classes

For the 2014-19 regulatory control period, we propose that our current procedures for assigning new retail customers to tariff classes, or reassigning existing retail customers from one tariff class to another be continued, with some modifications to reflect recent amendments to the rules applying to retail customers and their tariffs. We believe that our current procedures are consistent with the requirements set out in clause 6.18.6 of the rules because it takes into account the voltage level of the connection, the type of metering installed in the premise and the level of energy consumption and maximum demand at each individual connection point.

Our proposed procedures also involve an annual review to assess whether existing connection points need to be re-assigned to new tariff classes due to a recent change in annual usage and/or their connection arrangements.

Our proposed procedures are set out in Attachment 9.1. We request that the AER determine under clause 6.12.1(17) of the rules that these procedures apply to Essential Energy for the 2015-19 regulatory control period.

New tariff designs for the 2014-19 regulatory control period

For the 2014-19 regulatory control period, we will investigate the merit of changing our network tariff structures to ensure that our network tariffs continue to meet our objectives of revenue sufficiency, economic efficiency and equity in an environment of declining energy consumption.

Reporting arrangements for annual 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 charging, and how it reports on compliance during the course of the 2014-19 regulatory control 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 mechanisms

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 charge lists should 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 annual pricing proposal would need to show that the combined forecast revenue to be collected for these services should be equal to the maximum allowed revenue in the control mechanism.

The AER's stage 1 F&A sets out the following formula for control of standard control services revenue:

$$\textit{Maximum Allowed Revenue}_{\mathrm{t}} = \textit{Annual Smoothed Revenue}_{\mathrm{t}} + I_t + T_t + B_t$$

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 the under or over recovery in previous years (B adjustment). The latter issue arises when actual energy consumption is different to forecast volumes, leading to over or under recovery of revenues. We note that the issue of under and over recovery only arises for the standard control services provided by our distribution network.

The AER's final rate of return guideline incorporates an approach to the 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. Details of our proposed approach to estimating the revenue adjustment for the annual update to the cost of debt are outlined in Attachment 9.2. The revenue adjustment for the annual cost of debt update would be applied through the "B" factor adjustment above. Therefore, in the formula for control of standard control services revenue:

$$B_t = \textit{Adjustment for under or over recovery}_t + \textit{Adjustment for annual update to the cost of debt}$$

We consider that it is in the best interests of our customers that we are allowed to set our DUOS tariffs to achieve a non-zero closing balance of the unders and overs account in period t. It is important that we have this flexibility under the revenue cap for standard control services to ensure that we have the ability to constrain network tariff increases to CPI in the 2014-19 regulatory control period.

We propose that the AER's mechanisms for under or over recovery should be the same as that which applied for transmission charges in the 2009-14 regulatory control period. The mechanism is based on the closing balance in year t-2, and an estimate of the closing balance in year t-1. The under or over recovery in year t-1 is recovered via an adjustment in year t. This information would be reported to the AER in the annual pricing proposal.

Attachment 9.2 provides more information on our proposed arrangements to demonstrate compliance with control mechanisms, including the under or over recovery mechanism.

Transmission charging matters and designated pricing proposal charges

In addition to the payments we make to TransGrid, we are also required to make payments to other DNSPs and to pay avoided TUOS to eligible embedded generators. The charges we make to TransGrid and others are termed 'designated pricing proposal charges'. The rules require the AER to make a decision on how we report to the AER on our recovery of designated pricing proposal charges for each regulatory year of the 2014-19 regulatory control period, and on adjustments to account for under or over recovery of those charges.

Attachment 9.3 provides further information on how we propose to report on these charges and make adjustments for under or over recovery. We propose to use the mechanism we had in place during the 2009-14 regulatory control period for recovering these types of charges.

Jurisdictional scheme payments

The Rules allow us to recover jurisdictional scheme payments relating to obligations imposed by governments. The payments are not related to the network services we provide, and are separate to the maximum revenue or charges to customers for direct control services.

As part of its regulatory determination, the AER must make a decision on how we are to report to the AER on our recovery of jurisdictional scheme amounts for each regulatory year of the 2014-19 regulatory control period, and on adjustments for under or over recovery of those amounts. The AER's decision only relates to jurisdictional scheme obligations we have at the time the decision is made.

For the 2014-19 regulatory control period, we will have a continuing jurisdictional scheme obligation to make payments to the NSW Government for the Climate Change Fund to cover the NSW Solar Bonus Scheme. Essential Energy will also require the inclusion of Queensland Solar Rebates as a jurisdictional scheme and include the recovery of this through tariffs in a method similar to the Climate Change Fund.

We propose the same mechanism for reporting on recovery of jurisdictional scheme amounts to that in place during the 2009-14 regulatory control period, including the mechanism for under or over recovery adjustments. The current mechanism is based on the audited closing balance in year t-2, and an estimate of the closing balance in year t-1. The over or under recovery in year t-1 is recovered via an adjustment in year t. This information is reported in the annual pricing proposal. Further information is provided at Attachment 9.4.

Negotiating Framework

As noted in Chapter 3 of our proposal, none of the services we currently provide is classified as negotiated distribution services and therefore we are not required to submit a negotiating framework.

ATTACHMENTS TO THE REGULATORY PROPOSAL

Attachment number	Attachment name
A.1	Customer overview paper
E.1	Delivering efficiencies for our customers
E.2	Stakeholder engagement framework
2.1	IPSOS customer research report
2.2	How customer engagement informed our regulatory proposal
2.3	Disconnecting remote communities from the Network
3.1	Classification proposal
3.2	Proposed application of STPIS
4.1	Post Tax Revenue Model
4.2	Roll Forward Model
4.3	EBSS carryover amount calculation
4.4	Calculation of D-factor and DMIA adjustment for 2009-14
4.5	Consumption forecasts
4.6	Pass through event proposal [CONFIDENTIAL]
4.7	Review of regulatory treatment of risks
5.1	Report on 2009-14 regulatory control period actuals versus allowances
5.2	Network Asset Management Plan
5.3	Addressing the capital expenditure and operating expenditure objectives, criteria and factors
5.4	Addressing the benchmarking factor for capital expenditure and operating expenditure
5.5	Labour escalators
5.6	Cost escalation report
5.7	Cost escalation model
5.8	Connection policy
5.9	Key assumptions underlying capital expenditure and operating expenditure forecasts
5.10	Approved CAM
5.11	Assessment of revisions to clauses 6.5.6 and 6.5.7 of the NER
5.12	Capitalisation policy
5.13	Electricity network demand forecasting_draft
6.1	System operating expenditure strategy
6.2	Corporate overhead strategy
6.3	Divisional overhead strategy
6.4	Asset growth escalator
7.1	WACC estimates, a report for NSW DNSPs
7.2	Debt transition consistent with the NER and NEL
7.3	Efficiency of staggered debt issuance
7.4	Transition to a trailing average approach
7.5	Advice to Networks NSW [CONFIDENTIAL]
7.6	Credit ratings for regulated energy network services businesses
7.7	Debt raising costs for NSW DNSPs - Individual reports for Ausgrid, Endeavour and Essential

7.8	Scientific Background on the Sveriges Riksbank Prize in Economic Sciences in Memory of Alfred Nobel 2013, UNDERSTANDING ASSET PRICES
7.9	The Fama-French Three-Factor Model
7.10	Alternative versions of the dividend discount model and the implied cost of equity
7.11	Dividend discount model estimates of the cost of equity
7.12	The market, size and value premiums
7.13	MRP, analysis in response to the AER's draft rate of return guideline
7.14	Estimating the return on the market
7.15	Estimating the E[Rm] in the context of recent regulatory debate
7.16	Cost of equity in the Black Capital Asset Pricing Model
7.17	Estimates of the zero beta premium
7.18	Equity beta
7.19	Regression-based estimates of risk parameters for the benchmark firm
7.20	Information on equity beta from US companies
7.21	Equity beta issues paper: International comparators
7.22	Comparison of OLS and LAD regression techniques for estimating beta
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	Water utility beta estimation
7.26	Essential Energy's Gamma Proposal
7.27	An appropriate regulatory estimate of gamma
7.28	Imputation credits and equity prices and returns
7.29	Updated dividend drop-off estimate of theta
7.30	The payout ratio
7.31	"Imputation Credit Redemption ATO data 1988-2011"
7.32	Submission on the rate of return consultation paper
7.33	Submission on the draft rate of return guideline
7.34	NNSW response to AER letter on cost of debt averaging periods
8.1	Public lighting proposal [CONFIDENTIAL]
8.2	Public lighting models
8.3	Charges for public lighting
8.4	Type 5 and 6 metering services proposal
8.5	Type 5 and 6 metering services model
8.6	Type 5 and 6 metering services PTRM
8.7	Charges for type 5 and 6 metering services
8.8	Ancillary Network Services Proposal
8.9	Ancillary Network Services Models
8.10	Charges for Ancillary Network Services
8.11	True up for alternative control services
9.1	Proposed procedures for assigning customers to tariff classes
9.2	Application and demonstration of compliance with control mechanisms for standard and alternative control services
9.3	Reporting on recovery of designated pricing proposal charges
9.4	Reporting on recovery of jurisdictional schemes
9.5	Service categories and tariff components
Appendix 1	Reference table - Compliance with National Electricity Rules

GLOSSARY

Term	Definition
($ nominal) [for paragraphs]	$XXXXX million ($ nominal) This is the dollar of the day
($ million) [for Tables]	Nominal dollars for Table/Figure captions e.g. Opening RAB ($ million, nominal)
(2013 – 14 dollars)	$XXXXX ($2013-14) Real dollars. This denotes the dollar terms as at 30 June 2014
($ million, 2013-14) [for Tables]	Real dollars for Table/Figure captions e.g. Table 5-5 – Forecast capital expenditure ($ million, 2013-14)
2009-14 regulatory control period	The regulatory control period commencing 1 July 2009 and ending 30 June 2014
2014-19 regulatory control period	The period comprising bot the transitional regulatory control period 1 July 2014 to 30 June 2015 and the 2015-19 regulatory control period
2015-19 regulatory control period	The regulatory control period commencing 1 July 2015 and ending 30 June 2019
2019-24 regulatory control period	The regulatory control period commencing 1 July 2019 and ending 30 June 2024
ACS	Alternative control services
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AMP	Asset management plan
ARR	Annual revenue requirement
ASP	Accredited Service Provider
Augex	AER's augmentation expenditure model
CAM	Cost allocation method
CAPM	Capital Asset Pricing Model
CCF	Climate Change Fund
CESS	Capital Expenditure Sharing Scheme
CPI	Consumer Price Index
CRNP	Cost Reflective Network Price
DAPR	Distribution Annual Planning Report
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution network service provider

DUOS	Distribution Use of System
EBSS	Efficiency Benefit Sharing Scheme
F&A	Framework and approach paper
FMECA	Failure modes effects criticality analysis
IPART	Independent Pricing and Regulatory Tribunal of NSW
MRIM	Manually read interval meter
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NMI	National Metering Identifier
NUOS	Network Use Of System
PTRM	Post tax revenue model
RAB	Regulatory asset base
Regulatory proposal	Essential Energy's regulatory proposal for the 2014-19 regulatory control period submitted under clause 6.8 of the NER
Repex	AER's replacement expenditure model
RIN	Regulatory Information Notice
RFM	Roll Forward Model
Rules	National Electricity Rules
SCS	Standard control services
STPIS	Service target performance incentive scheme
Subsequent regulatory control period	Regulatory control period 1 July 2015 to 30 June 2019
Transitional NER	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 year
Transitional regulatory proposal	Regulatory proposal prepared in accordance with the transitional NER
Transitional year	The transitional regulatory control period 1 July 2014 to 30 June 2015
TSA	Transitional Services Agreement
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital