TRANSITIONAL REGULATORY PROPOSAL TO THE AUSTRALIAN ENERGY REGULATOR

DELIVERING BETTER VALUE

1 JULY 2014 – 30 JUNE 2015

Endeavour Energy

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SUMMARY

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

The Australian Energy Regulator (AER) administers the rules that determine the investment plans and revenue of electricity distributors in the National Electricity Market (NEM). Every five years, electricity distributors must submit proposals to the AER that explain their capital and operating plans and what they believe the revenue requirements are to fund those plans.

A new regulatory proposal was due to be submitted by the NSW and ACT electricity distribution businesses for the period 2014-15 to 2018-19 (2014-19). During 2012 and 2013 the Australian Energy Market Commission (AEMC) consulted on major rule change proposals covering the National Electricity Rules (NER or rules) and approved a number of changes. The NSW and ACT distribution network businesses were to be the first organisations to submit proposals under these new rules.

During this rule change consultation, all parties agreed that a one year transitional proposal would help smooth the implementation of the new rules given the short implementation period available to NSW and the ACT after the rule change came into effect.

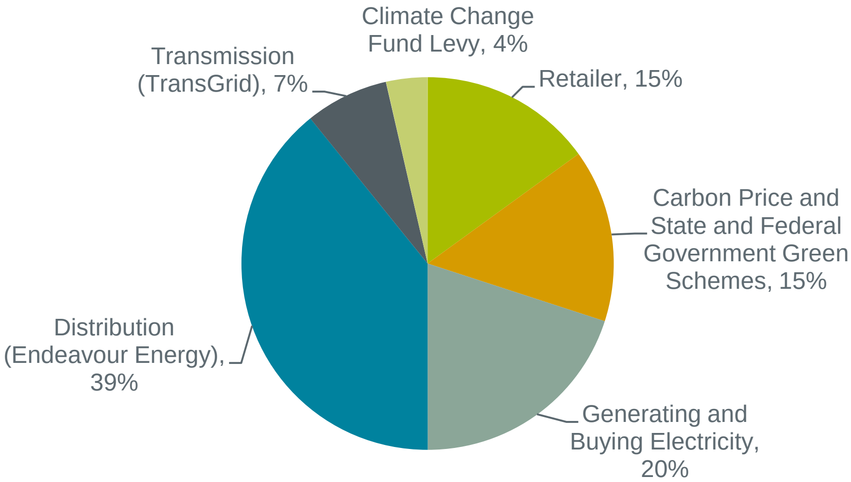
This transitional proposal covers just the 2014-15 financial year, the first year of the five year regulatory period, while providing an indication of key requirements for the total five year period. The requirements to deliver Endeavour Energy's capital and operating plans for the remaining four years of the regulatory period will be covered in a substantive proposal to be submitted to the AER in May 2014.

Endeavour Energy's transitional proposal has been prepared in accordance with the requirements of the transitional chapter 6 and Division 2 of part ZW of Chapter 11 of the rules.

Explaining our role

Endeavour Energy builds, maintains and operates the electricity distribution network in Sydney's Greater West, the Illawarra and South Coast, the Blue Mountains and the Southern Highlands, This requires ongoing significant investment each year. Our charges are provided to electricity retailers and when combined with TransGrid's transmission charges represent just under half of customers' electricity bills. On average, your total electricity charges break down into the components shown in figure 1 below:

Figure 1: Components of Electricity Charges[1]



[1] IPART, http://www.ipart.nsw.gov.au/Home/For_Consumers/Why_electricity_costs_what_it_does

SUMMARY

NSW Government Network Reform Program

In March 2012 the NSW Government announced a restructure of the three NSW electricity distribution organisations namely Endeavour Energy, Essential Energy, and Ausgrid. That restructure commenced on 1 July 2012 with objectives to continuously improve safety performance, maintain network reliability, and to strive to contain increases in our share of customers' electricity bills to at or below CPI.

The network reform program has focussed on applying rigorous strategic, operational and financial discipline to both the capital and operating programs. This has delivered total savings for all NSW electricity distribution entities of $1.1 billion in the 2012-13 financial year with current projected savings of $4.3 billion over the five year period commencing July 2011. The benefits for Endeavour Energy of the network reform program are included in this transitional regulatory submission and will result in lower distribution network bills for our customers.

Transitional submission highlights

Compared to the current 2013-14 year, Endeavour Energy's share of an average household and small business electricity bill will decrease in 2014-15 by 0.24%, which is 2.68% below the forecast rate of inflation. The typical impact for residential and small business customers is contained in the table below:

Table 1: Bill impact from network charges for typical residential and small business customers (including metering)

$pa; Nominal	2013-14	2014-15	Change ($)	Change (%)
Residential customer consuming 6MWh p.a.	705.58	703.87	-$1.71	-0.24%
Small business customer consuming 26MWh	2,375.35	2,369.60	-$5.75	-0.24%

The key drivers of this outcome are:

- The five year capital program will reduce from $3.0 billion approved by the AER for the 2009-14 regulatory period to a proposed $1.9 billion for the 2014-19 period[2] – a reduction of 37%, which is 44% below the forecast of inflation over the five year period;
- The five year operating program will increase from $1.7 billion approved by the AER for the 2009-14 regulatory period to a proposed $1.8 billion for the 2014-19 period[3] – an increase of 7%, which is 5% below the forecast of inflation over the five year period;
- We expect, on average, our customers will continue to reduce their use of electricity by 1.6% per annum over the five years commencing 1 July 2014. This expectation is a consequence of the continuing take up of domestic solar panels, the high Australian dollar impacting Australian manufacturing and the continuing impact of double digit electricity price increases from July 2009 to July 2011; and
- We expect that based on the proposed capital and operating program the current network reliability will be maintained or marginally improved for the regulatory period.

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

SUMMARY

Better customer engagement

We have used a variety of channels to reach out and listen to our customers on the operations of Endeavour Energy and most importantly how these operations impact our customers' lives. These channels include qualitative and quantitative customer research, targeted stakeholder meetings and presentations, social media and customer correspondence. These opportunities for communication have varied depending on the type of customers, their communication preferences and availability of open two way channels of communications.

New customer engagement guidelines established by the AER give Endeavour Energy the opportunity to significantly expand and improve on this two way communication. To this end, Endeavour Energy has partnered with Essential Energy and Ausgrid to launch an innovative, low cost social media campaign which is proving to be a highly successful engagement channel.

Endeavour Energy has developed a framework for the way it will engage with its customers. This framework and initial engagement activities have assisted in the development of this transitional proposal. Further and more detailed activity will increase over time and will be explained in more depth in Endeavour Energy's substantive proposal.

Endeavour Energy expects that this engagement framework will help ensure its operations and services become better aligned with the long term interests of electricity customers. It expects that clear and accurate communication will be delivered at the appropriate time and give customers greater understanding of its operations and how and why they are funded.

This plan will also outline how Endeavour Energy will embed better customer engagement practices into its business as usual practices and how it will continuously assess and measure its engagement actions to ensure they remain effective, open and transparent to all its customers.

ENDEAVOUR ENERGY AND OUR CUSTOMERS

01

Our network

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

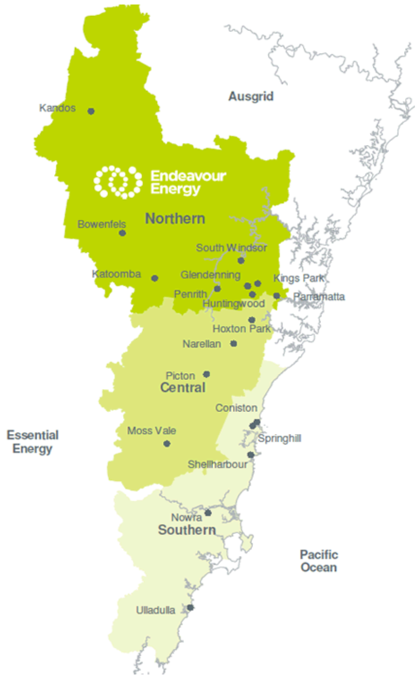
Endeavour Energy manages a $5.3 billion electricity distribution network for 907,996 customers, or 2.2 million people, in households and businesses across a network area spanning 24,500 square kilometres in Sydney's Greater West, the Illawarra and South Coast, the Blue Mountains and the Southern Highlands.

Our network also covers Sydney's North West and South West Growth Centres – areas earmarked by the NSW Government for future housing development. Between them, these Centres cover 27,000 hectares and will become home to more than 500,000 people in more than 180,000 dwellings.

We are preparing to meet this extra growth and maintain our existing network by investing responsibly and efficiently in our network over the next regulatory period.

The focus of our 2,600 people is to deliver a safe and reliable electricity supply to our residential and business customers as efficiently as possible while delivering consistent results to our shareholder, the NSW Government.

Figure 2: Endeavour Energy's franchise area



We are committed to making a serious and sincere effort to deliver better value for our customers by reducing our costs without compromising safety or services.

How our network transports electricity

The NSW electricity supply sector involves generation, transmission, distribution and retail sellers.

Endeavour Energy builds and operates an electrical network that transports electricity from the high voltage transmission network to customers' homes and businesses.

Power plants typically generate electricity a long way from homes and businesses. It is transported at high voltages to bulk supply points over the transmission system operated by TransGrid. From here Endeavour Energy transports to our 22 sub transmission and 155 zone substations.

Zone substations, which typically service entire suburbs, transform electricity to mid voltage levels (11kV).

When electricity arrives at the location where it is required, distribution substations further transform the electricity to 415V or 240V. Power lines then carry low voltage electricity to consumers for their home, office and factory use.

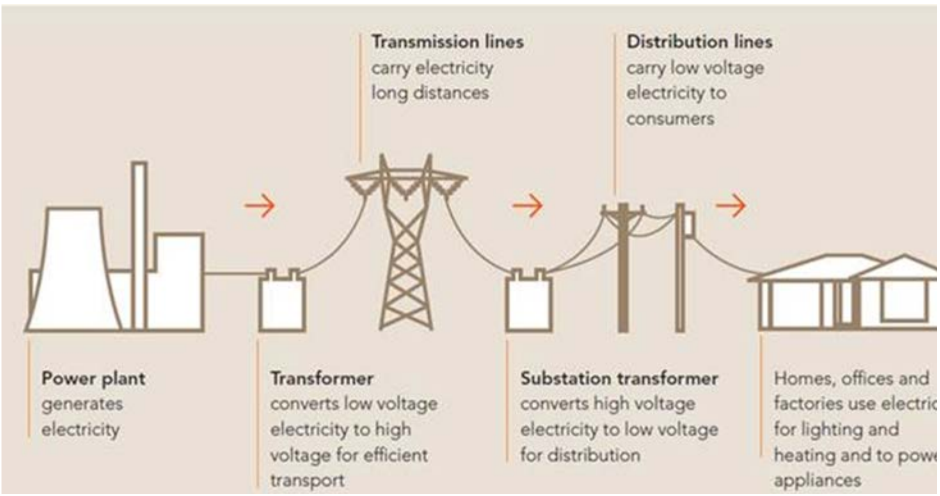


Figure 3: Electricity industry structure, Source: AEMO

ENDEAVOUR ENERGY AND OUR CUSTOMERS 01

Our business purpose

To be of service to our communities by efficiently distributing electricity to our customers in a way that is safe, reliable and sustainable.

Our values

These five values form 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

Continuous improvement

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

Customer and community focus

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

Act with integrity

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

Customer focus and objectives

Endeavour Energy's long standing commitment to our customers and our communities is encapsulated in our core values. These values form the basis for everything we do and guide and shape our actions and decisions.

Our commitment to our customers and communities requires us to deliver value and provide reliable service to our customers and communities; to use resources responsibly and efficiently; and to be environmentally and socially responsible.

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

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

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

Our customer engagement program

Endeavour Energy supports the renewed focus given to the nature, quality and extent of our engagement with end use customers by the Australian Energy Market Commission and the Australian Energy Regulator.

We have developed an engagement program which focuses on encouraging customers and stakeholders to better understand our business and to also have a significant say in the way we operate. We are committed to improving the way we inform and listen to our customers about our operations, and are working through a four phase approach to guide our investment decisions.

The diagram below outlines the key activities in Endeavour Energy's customer engagement framework, including proposed timeframes:

Figure 4: Customer Engagement Process

What we have learned from our customers

During the current regulatory period, we conducted research with residents and businesses which explored customers' willingness to pay across seven main topics:

1. **Pricing:** perceptions around pricing and recent increases; and the way this has affected behaviour, including electricity use.
2. **Reliability:** customers' perceptions and experiences of power supply interruptions; and the relationship between reliability and price, and customers' willingness, or otherwise, to pay more to increase reliability.
3. **Construction/design standards:** connection costs; the role of aesthetics including overground/underground options; and perceptions about environmental and safety considerations and options.
4. **Metering technology:** attitudes towards advanced metering and the perceived value of its various features; and willingness to pay for this technology.
5. **Demand management/energy efficiency:** customers' views about a range of energy efficiency initiatives; and willingness to pay for these programs.
6. **Support for vulnerable households:** views about who should receive what support; and the willingness to pay to make sure this support is available.
7. **Communication and engagement:** exploration of needs and wants in relation to information provided by Endeavour Energy.

This research included a wide range of our customers – from students to full-time employees to retirees; single-person households to families; tenants and owner-occupiers; and business and industry. Low-income and vulnerable customers were also represented.

What the research showed:

1. **Pricing:** Many people mistakenly think Endeavour Energy is privately-owned, rather than a State Government entity. This means some customers think increasing prices over the past five years were designed to generate large profits, rather than fund infrastructure and maintenance programs.

   Significant price rises in our share of electricity bills over the past five years upset our customers. Many were confused about the reason for the increases and most modified usage in an attempt to reduce their bills. Customers expected revenue to be invested in the network, rather than contributing to profit. There was an overwhelming preference for steady price increases rather than an initial steep increase.

2. **Reliability:** Businesses particularly, and most residents were happy with the level of reliability they receive from Endeavour Energy and so were not particularly willing to pay more for a more reliable service – 75 per cent of domestic customers and 92 per cent of businesses felt this way. Nor were they willing to accept a less reliable service in exchange for a lower bill.

   Most people understood that when the power was unexpectedly interrupted, Endeavour Energy did its best to get the power back on as quickly as possible. When there is an outage, most customers want to know when the power will be back on. A minority wanted to know the cause of the outage.

3. **Construction and design standards:** Customers were surprised to learn undergrounding power lines costs four to ten times as much as putting them overhead, only a quarter of surveyed customers were willing to pay more to replace overhead lines with underground cabling.

4. **Safety:** Customers expect us to provide a safe network and believe this should be factored into design and maintenance of the network. A majority were not willing to pay less for lesser safety standards.

5. **Demand management and energy efficiency:** Customers want to retain control of their energy usage, their meter and the way in which they are charged for energy usage. They were less willing to pay more for technology such as smart meters, but valued information on how they might better manage their energy usage from Endeavour Energy.

6. **Support for vulnerable households:** Customers believed that the company which sends customers the bill is the one best placed to support vulnerable households.

7. **Communication and engagement:** Most value easy to access information about how and where they can minimise their electricity bill.

In summary, the three main service aspects prioritised by customers were the same for both residents and businesses – costs, reliability and safety. Cost was clearly seen as the most important priority.

Endeavour Energy, Essential Energy and Ausgrid have also jointly launched an innovative, low cost social media campaign to engage customers on a wide variety of topics ranging from prices and reliability to vegetation management and streetlights. This is already proving to be a highly successful, new engagement channel.[4]

We plan to describe our engagement initiatives and findings in our substantive proposal, as required by the AER guidelines.

In the interim, we have based our transitional proposal on three priorities central to the interests of all end use customers and our stakeholders:

- **Safety** by continuously improving our safety performance for employees, contractors and the public;
- **Affordability** by striving to contain average increases in our share of customers' electricity bills to at or below CPI; and
- **Reliability** by ensuring the ongoing reliability, security and sustainability of the network.

These overarching objectives are consistent with the National Electricity objective (NEO) and the revenue and pricing principles laid down in the National Electricity Law (NEL). The NEL governs the exercise of the AER's economic regulation function, including decisions about the revenue (and therefore the price) that electricity network businesses like Endeavour Energy can recover.

The objective of the NEL is to:

> *"...promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity supply with respect to –*
>
> *(a) Price, quality and safety, reliability and security of supply of the electricity, and*
> *(b) The reliability, safety and security of supply of the national electricity system."*

While the NEL places the long term interest of network customers first, it also recognises the importance of allowing electricity network businesses enough expenditure to perform core functions. The NEL recognises we should be provided with a reasonable opportunity to recover at least the efficient costs we incur in providing network services and in complying with our obligations.

In addition we recognise the cost of meeting these challenges and voluntarily committed to achieving substantial operating efficiency improvements over the current period.

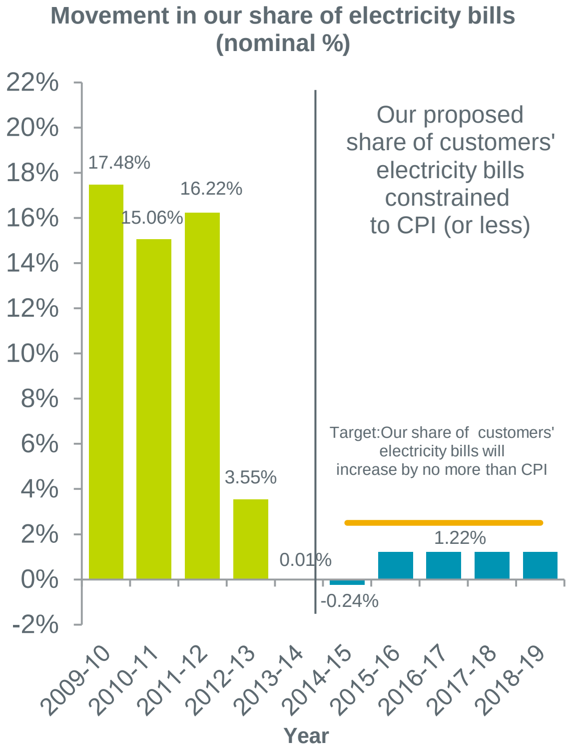
We have more than met this challenge, and those improvements are reflected in the operating cost forecasts contained in this transitional proposal.

[4] https://www.facebook.com/YourPowerYourSay

Our current environment

Changes over the current regulatory period

Several events during the current regulatory period influenced our performance and changed our business. In particular, our efficiency programs, our capital delivery strategy, the sale of our retail business, the creation of Networks NSW and the prolonged impact of the Global Financial Crisis (GFC) each influenced the cost of servicing our customers.



Lower than forecast energy consumption was driven by the impact of high electricity bills on customer behaviour, the high Australian dollar and the increase in small scale solar systems. While these factors culminated in declining demand, peak demand growth rates have not reduced in the same significant manner.

We reviewed our capital program and actively reduced operating expenditure in order to minimise future network bill increases. In addition to deferring capital expenditure where appropriate, we improved our efficiency in delivering capital projects. Our focus on efficiency is demonstrated by a blended delivery approach. We used a mix of internal and external resources, resulting in a significant percentage of market-tested and externally sourced investment.

Our sourcing of network investment from the market has delivered unit cost savings of around 10-15% for completed capital projects, compared to the 2004-05 to 2008-09 period. We are now in a strong position to reduce our capital expenditure during the next regulatory period. These reductions will flow from a combination of fewer capital projects (primarily due to lower demand growth), lower unit costs and better targeting of our capital projects to deliver customer outcomes.

We also delivered on our voluntary commitment to the AER in our 2009-14 regulatory proposal to reduce our labour operating costs by 2% each year over the regulatory period, which the AER accounted for in the approved operating expenditure allowances. We exceeded this target due to the commitment of all of our employees to deliver improved value through our efficiency programs.

During the regulatory period our retail business was sold. This resulted in a reallocation of efficient corporate costs to standard control services as recognised by the AER in its pass through decision. Our efficiency initiatives have ensured that the forecast operating expenditure does not exceed the AER approved 2013-14 operating expenditure allowance in real terms despite this reallocation of costs.

We are also responding to our customers' concern about electricity affordability by seeking to limit network bill increases to at or below CPI. On 1 July 2013, Endeavour Energy customers had no real price increase in the network component of their bill for the first time in a decade.

Network reform program

Under the NSW Government Network Reform Program a joint Board of Directors and a common Chief Executive Officer have been appointed for Endeavour Energy, Essential Energy and Ausgrid. There is a common operating model for each of the three network businesses and an umbrella group called Networks NSW responsible for identifying and driving efficiencies in the operations of the three network businesses. The key focus areas of Networks NSW generated reform include:

1. **New operating model initiatives** -These initiatives relate to streamlining both corporate and support services, removing functional duplication, and sharing better practices between the three companies.

2. **Strategy and policy initiatives** -These initiatives relate to policy changes for consistently better practice across the three distributors, particularly in network areas such as reliability planning, maintenance and renewal policies, fleet strategy and property portfolio management.

3. **Capex efficiency initiatives** - These initiatives relate to improved capital evaluation and capital management across the three distributors in relation to expenditure on the network, as well as on fleet, property, and technology.

4. **Procurement and logistic initiatives** - These initiatives will create repeatable, auditable, controlled and faster sourcing processes that will drive significant procurement savings across a number of product and service categories.

This industry reform has accelerated the pace at which we are achieving our internal efficiency goals. The benefits of the network reform program and our internal efficiency program are included in this transitional regulatory submission and will help meet the long term interests of our customers.

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

Current period performance

In our regulatory proposal lodged with the AER in June 2008 we committed to annual labour operating cost efficiency improvements (compared to our 2008 figures) of 2% per annum.

In addition, a three-year efficiency program incorporating employee driven ideas across the company allowed us to exceed our savings targets and keep our commitment to improving value to customers.

This Customer Value Improved Program (CVIP) sought to reduce costs by controlling discretionary expenditure, finding new ways to undertake existing tasks and to explore activities that could add value for our customers at no additional cost. We exceeded our savings target.

The capital investment program for the 2009-2014 period represented a peak in capital investment volumes. We expect to return to sustainable long-term investment programs from 2014-15 onwards. We responded to the peak challenge of network investment by a strategy of peak resourcing from the private sector. The strategy combined external contractors with our own employees for program delivery and management. The approach will continue to be employed to achieve efficient, flexible and sustainable customer delivery for future periods.

Efficiency culture

Endeavour Energy made an efficiency saving of about $54 million in the first year of the current period. Savings in the five year period ending June 2014 are likely to total $300 million.

The peak investment program was developed in response to the introduction of new licence conditions and reliability standards, and significant forecast demand growth. We also sought to maintain the reliability and quality of our supply by replacing ageing assets and increasing network capacity for new customers. The program has significantly improved the resilience of our network to extreme weather, natural disasters, and peak demand conditions.

Transitional proposal process

The AER regulates the Australian energy industry. Every five years, electricity distributors such as Endeavour Energy must submit a proposal to the AER that outlines capital and operating costs and the revenue required to fund them. The AER and the AEMC identified the need for a transitional proposal for the 2014-15 financial year during consultations that took place with the industry during 2012-13 to support the rule change process.

The AEMC decided transitional arrangements would be required for the next round of NSW and ACT determinations to bridge the gap between the introduction of new rules and the next full regulatory period from 2014-19. Transitional arrangements were put in place to delay the lodgement of the five year regulatory proposal by one year.

This transitional regulatory period provides for the continuation of several existing regulatory arrangements, while allowing for the introduction of key elements in the new regulatory arrangements, specifically the outcomes of the AER's current Better Regulation program.

Our transitional proposal focuses on:

- reasonable guidance regarding the forecast expenditure programs by the network service providers;
- an estimated range for the potential cost of capital outcomes; and
- the approach to smoothing the price changes arising from these programs over the following five years.

Our proposal for the transitional 2014-15 year has been prepared according to the provisions set out in Division 2 of part ZW of Chapter 11 and, as modified, the rules contained in Chapter 6. In accordance with these rules, this determination will be revised when we submit a full regulatory proposal to the AER in May 2014. The AER will apply the new regulatory arrangements and outcomes of the Better Regulation program.

The AER will reconcile our revised expenditure and revenue outcomes with the transitional year approval. A net present value (NPV) neutral adjustment to revenue will then be made to the subsequent regulatory years to adjust for any differences in the transitional proposal and the full regulatory determination.

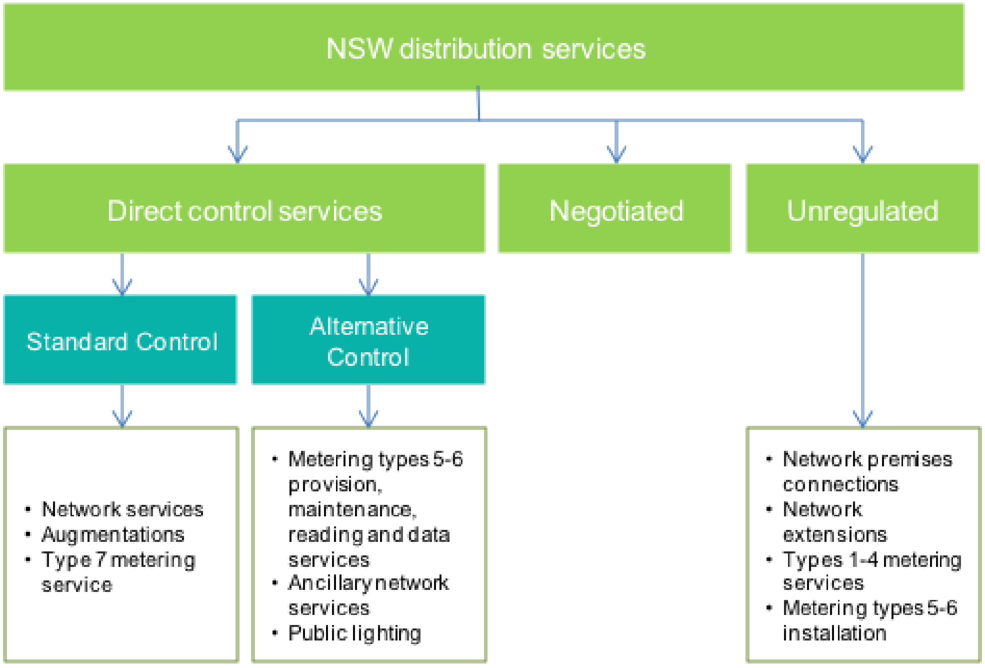
Outcomes of the AER’s framework and approach papers - Stage 1

As a result of the transitional arrangements and Better Regulation program, the framework and approach (F&A) paper was divided into two parts. The F&A arrangements apply to both the one-year transitional period and the subsequent regulatory control period. The outcomes and implications of the decisions contained in each respective F&A stage are outlined below.

The F&A Stage 1 paper, published in March 2013, classified distribution services, established associated control mechanisms and pricing of dual function assets according to cl 11.56.4(l)(1). The outcomes of this paper apply to both the transitional regulatory proposal and the full regulatory proposal.

The AER has proposed to classify Endeavour Energy’s distribution services as set out in figure 5:

Figure 5: Framework and approach 1 outcomes for classification of services



The following services were newly classified as alternative control services:

- metering type 5-6 provision, maintenance, reading and data services; and
- ancillary network services (formerly known as miscellaneous and monopoly fees)

In essence, standard control services comprise distribution services that are integral to electricity supply and are relied upon by the majority of our customers. Alternative control services involve customer specific or customer requested services. These services are provided to a particular group of customers or individual customers who request the service.

The AER has unbundled these services from our standard control services to promote competition, facilitate customer choice and remove any subsidies between existing services. This user-pays approach should reduce the price charged for standard control services while introducing additional charges for users of type 5-6 metering (see ancillary network services). The intention of this change is to better target our collection of costs from the actual users of these newly classified services.

The form of control mechanism for these services will be:

- standard control services – revenue cap
- alternative control services – caps on prices of individual services.

The AER noted that a control mechanism basis for the newly classified services will be confirmed in its determination. Accordingly, Chapter 5 of this transitional proposal submits a basis of control for these services.

Outcomes of the AER’s framework and approach papers - Stage 2

The Stage 2 F&A is required to be published by 31 January 2014, the same day we are due to lodge this transitional proposal to the AER. This F&A relates to the matters specified under cl 11.56.4(l)(2), namely the application of guidelines, incentive schemes and any alterations to the transitional arrangements such as AER’s true-up mechanism. This transitional proposal has been prepared in accordance with discussions with the AER and the draft guidelines and incentive schemes.

Our submission assumes the following:

- the Efficiency Benefit Sharing Scheme (EBSS) will apply to the 2014-15 year (and subsequent 4 years), and carry-over amounts accrued over the 2009-14 regulatory period will be applied to the revenue requirement in the interests of preserving incentives and pricing stability;
- the Capital Expenditure Sharing Scheme (CESS) should apply in accordance with the guideline from year 2 (2015-16) onwards;
- the Service Target Performance Incentive Scheme (STPIS) with revenue at risk will apply from 2015-16 onwards while for the transitional year the current data collection-only approach will continue;
- the Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS) will carry over the existing arrangements of the current regulatory period although the D-factor will be removed;
- forecast depreciation will be used to roll forward the asset base at the next reset;
- a rate of return has been developed in consideration of the latest available market information and the Final Rate of Return Guideline;
- newly established customer engagement and shared asset guidelines and capex incentive scheme and capital expenditure ex-post review do not apply to this transitional proposal; and
- any modifications to the calculation of an NPV neutral true up mechanism will be as specified.

We have prepared this proposal in accordance with the above to achieve and maintain pricing stability between periods.

Giving proper effect to the AER’s classification of services

The rules require that we propose an annual revenue requirement for standard control services for the transitional year. We must also provide an indicative range of revenue requirements for the 2014-19 regulatory years and indicative prices for direct control services, i.e. standard and alternative control services.

As noted above, the AER has re-classified some of our services from standard control to alternative control including metering and ancillary services. To give effect to the AER’s re-classification, we need to allocate the costs of providing these services to the correct class of services in order to develop indicative prices for the transitional year.

However, an anomaly in the transitional rules means that we are prevented from allocating costs to these services for the transitional year. The rules state that costs which have been allocated to a particular service cannot be reallocated to another service during the course of a regulatory control period. For the purposes of this rule, the transitional year is treated as a part of the current regulatory control period. The requirements of the transitional rules mean that proper effect cannot be given to the AER’s classification of services for the transitional year.

The NSW DNSPs have had discussions with the AER on the approach to fulfilling the rules requirements for the transitional proposal, particularly the provision of indicative prices. On 11 December 2013, the AER wrote to Networks NSW outlining their view of a preferred approach to setting indicative prices for the transitional year. We have largely adopted the AER’s preferred approach which seeks to minimise changes during the transitional year.

The AER’s preferred view has impacted the way we have developed our proposal. While we have been clear that the AER’s classification of services is applicable for the transitional year, we have included the costs of providing these re-classified services in the standard control services cost pool, where the costs will be recouped through DUOS prices. We have made clear however that the Annual Revenue Requirement only relates to standard control services as defined by the AER in Stage 1 of its framework and approach paper.

Importantly, the AER’s preferred method has impacted the way we have presented indicative prices for these services:

- Metering type 5-6: the AER considers that new prices should not be established for the transitional year as the transitional rules prevent the re-allocation of costs from standard control service to alternative control service for the transitional year. Instead we understand that the AER prefers to leave the costs of providing type 5-6 metering services within the standard control services cost pool and these costs are to be recouped through prices for standard control services (i.e. DUOS prices). This approach is the same as how metering type 5-6 services costs are being recovered in the current period (because they are classified as standard control services for the current period).
- For those ancillary network services currently being provided and have existing prices, the AER prefers to apply CPI to these prices, as required by clause 11.56.3(j) of the Rules.
- For those ancillary network services currently being provided but there are no existing prices and the costs are currently captured as part of the standard control service cost pool (because these services are classified as standard control services for the current period), the AER prefers to leave the costs of providing these services in the standard control services cost and recovered through DUOS prices for the transitional year.

Endeavour Energy considers that further clarification from the AER would assist in the effective implementation of the AER's preferred approach for the transitional period. Of significance is clarity around the revenue amount that will be used for adjustments to the annual revenue requirement of the subsequent period and to demonstrate compliance with the control mechanism. This is set out in detail in Attachment I

Information provided to meet rules compliance

The rules relating to the transitional proposal require Endeavour Energy to submit information to the AER to help make a decision:

- Chapter 3 provides information relating to the AER's decision on standard control services, including the proposed revenue requirement for 2014-15 and other additional information, including indicative prices for the standard control element of direct control services. It also explains how the proposed expenditure (summarised in chapter 4) is consistent with the proposed annual revenue requirement;
- Chapter 4 meets our requirement to provide a summary of the plan for expenditure for the transitional regulatory period and the subsequent four regulatory years; and
- Chapter 5 provides information relating to alternative control services including indicative prices for the following elements of direct control services: metering, public lighting and ancillary services.

Our proposed expenditure plan contained in Chapter 4 has been taken into account in the calculation of our annual revenue requirement set out in Chapter 3. Therefore our plan and estimate of expenditure for the 2014-19 regulatory control period is consistent with our proposed annual revenue requirements for 2014-15.

In addition to the above requirements, we must also submit a proposed connection policy, which is provided in Attachment H.

We are also required to identify any parts of the regulatory proposal which we claim to be confidential. We can confirm that part of the post-tax revenue model (PTRM) to be submitted with this regulatory proposal is confidential. A confidential version of all PTRMs is submitted to the AER, whilst additional versions are provided for publication which excludes customer specific information.

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For the transitional regulatory control period we require $1,007 million (nominal) from our 2014-15 DUOS charges. In the transitional year the revenue we require is made up of our annual revenue requirement of $988 million (nominal) and an adjustment to recover the costs of newly classified alternative control services of $63 million (nominal). These respective revenue amounts have been combined and smoothed to calculate the proposed bundled revenue of $1,007 million.

Affordability

We propose an amount of $1,007 million (nominal) to be recovered from our 2014-15 DUOS charges. Compared to 2013-14 our share of a customer's electricity bill will decrease by 2.68% below the rate of inflation. Our 2nd consecutive year pricing at or below the rate of inflation.

This addition to the annual revenue requirement is required in order to comply with the transitional rules and the AER's preferred approach as outlined in Chapter 2. In the following sections, we submit the following information with regard to our revenue requirements for these services:

- we show our proposed annual revenue requirement for the 2014-15 transitional year. We also provide the indicative range of our revenue requirements for the complete regulatory period;
- we outline the key inputs we have used to develop our annual revenue requirement for 2014-15 and the range of our proposed revenue requirements for the 2014-19 period;
- we show our proposed bundled revenue requirement for the 2014-15 transitional year; and
- we demonstrate how our proposed revenue for 2014-15 minimises price variations for standard control services and we also provide indicative prices and bill impacts for the transitional year.

Our network prices for 2014-19 are calculated using the AER's PTRM, provided in Attachment A3. The PTRM uses capex, opex, tax and financing cost inputs to determine the level of revenue needed to meet these costs.

Proposed revenue requirements

For 2014-15, we propose to recover indicative annual revenue requirement of $988 million in nominal terms. This is known as "placeholder" revenue. The AER will revisit this decision as part of its full determination for the 2014-19 regulatory period.

We note that a true-up mechanism (i.e. a review by the AER) will be used to deal with any difference between the 2014-15 placeholder revenue and the AER's substantive determination on allowed revenue for 2014-15. This method will adjust revenue allowances for the 2015-16 to 2018-19 regulatory years.

To limit the potential impact of any pricing adjustment on both Endeavour Energy and its customers, we have used our best forecasts of required capex and opex over the full 2014-19 regulatory period. We have smoothed the resulting revenue requirements over a five-year horizon to minimise price variability for customers between regulatory years and between regulatory periods.

The indicative range of revenue requirements over the 2014-19 regulatory period, is outlined in table 2. We have used a conservative weighted average cost of capital (WACC) of 8.52% to estimate our revenue requirements. In the table over the page we have estimated an indicative range for the revenue requirements using a range for the WACC of 8.52% to 9.11%[5] as required by the rules; all other inputs such as forecast capex and opex remain constant.

[5] This range is a nominal vanilla formulation, which means that the cost of equity is assumed to be post-tax and the cost of debt is pre-tax, before taking into account the fact that interest costs can be offset against taxable corporate income (i.e. not incorporating the interest tax shield). The AER's post-tax revenue model takes account of the interest tax shield within a separate tax building block cash flow.

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Our proposed WACC of 8.52% is based on a cost of debt of 7.55%, a cost of equity of 9.98% and a gearing level of 60%. The detailed parameters are set out in table 5 on page 18 of this proposal.

Table 2: Unsmoothed Forecast Annual Revenue

$m; Nominal	2012-13 (actual)	2013-14 (estimate)	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Actual/Estimated Revenue	1,018.4	1,015.0						
Low Case (8.52% WACC) Proposed	n/a	n/a	987.7	977.8	1,032.3	1,053.7	1,060.9	**5,112.4**
High Case (9.11% WACC)	n/a	n/a	1,027.4	1,020.4	1,077.2	1,100.5	1,109.8	**5,335.4**

Note: The revenues for 2012-14 are based on the current period definition of standard control services. The revenues for 2014-19 are based on the definition of standard control services as per the AER's framework and approach stage 1 paper.

We have based our proposed annual revenue for the next regulatory control period on inputs described in the subsequent sections.

This annual revenue requirement for the next regulatory period is lower than for the current period, and represents a transition to a more sustainable price path. This results from our ongoing efficiency programs and reforms. Expenditure pressures have been alleviated by:

- achieving our licence conditions;
- replacing a significant number of ageing assets in the current period;
- better management of stranded costs and dis-synergies resulting from the retail sale;
- reduced demand and growth forecasts; and
- delivering efficiency programs and savings driven by Endeavour Energy and Networks NSW.

Supporting inputs into the annual revenue requirement

The previous section provided an indicative estimate of our annual revenue requirement for the transitional year. It also contained an indication of the likely revenue required in the subsequent four years. The revenues were calculated using a building blocks approach and the AER's revenue model, the PTRM.

The building block components we have used to calculate our annual revenue requirement over the 2014-19 regulatory period are:

- a return on the value of the regulatory asset base (RAB), determined by multiplying the value of the RAB by our proposed rate of return:
  - the value of the RAB 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.
- a return of capital or regulatory depreciation;
- forecast operating expenditure;
- an estimate of the cost of corporate income tax for the transitional year; and
- an indicative revenue carry over amount from the application of the efficiency benefit sharing scheme (EBSS) in the 2009-14 regulatory control period.

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The building block components of our proposed indicative annual revenue requirements (unsmoothed) for 2014-19 are outlined in table 3 below:

Table 3: Nominal building block components for 2014-19

$m; Nominal	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Return on capital	476.6	510.0	536.2	557.9	580.8	**2,661.4**
Return of capital	62.6	72.3	83.1	88.1	93.3	**399.5**
Operating expenditure	291.8	300.4	302.6	304.5	316.0	**1,515.3**
Cost of corporate tax	59.1	61.8	68.2	69.0	70.8	**329.0**
EBSS Adjustment	97.5	33.3	42.3	34.2	0.0	**207.3**
Total indicative revenue (unsmoothed)	**987.7**	**977.8**	**1,032.3**	**1,053.7**	**1,060.9**	**5,112.4**

Indicative opening Regulatory Asset Base value

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

As the AER has changed the classification of type 5-6 metering services and ancillary network services to alternative control services from 1 July 2014, adjustments to the value of the RAB as at 1 July 2014 were necessary to exclude the values of assets used to provide type 5-6 metering services and ancillary network services. (See table 22, page 39 for a discussion of type 5-6 metering services.)

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

Table 4 below shows the roll forward of our RAB from 1 July 2009 to 30 June 2014:

Table 4: Indicative opening RAB value for standard control services as at 1 July 2014

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

Indicative range for rate of return

The transitional rules recognise the potential for volatility in the WACC parameters. Therefore, we are required to provide a range of WACC outcomes and associated revenue requirements for this proposal. Endeavour Energy proposes a conservative rate of return of 8.52 per cent. We used a trailing average approach to the cost of debt and a long-term average approach to the cost of equity informed by the range of relevant available evidence on the efficient cost of equity for energy networks.[6] We consider that a long term average approach is reflective of both the efficient costs of debt and equity for regulated energy networks. As the AER recognised in its final rate of return guideline, in the presence of re-financing risk, the benchmark efficient practice is to issue debt on a staggered portfolio basis.[7]

We also consider that investors in regulated utility firms are likely to invest over a long term horizon and it is reasonable to use long term historical data to set the efficient cost of equity over a five year regulatory control period. This approach smooths out short term volatility in data used to estimate the cost of equity. We have also had regard to prevailing conditions in the market for equity funds when developing our indicative rate of return for this transitional regulatory proposal. In addition, stable returns are an important driver in producing stable prices to customers over the long term.

We propose a cost of debt of 7.55 per cent, a cost of equity of 9.98 per cent, and a gearing level of 60 per cent.

Our proposed cost of equity has been informed by the opinion of expert economic consultants Competition Economics Group (CEG). Additional details on Endeavour Energy's approach to the rate of return are outlined in a report from CEG titled "WACC Estimates" provided as Attachment D.

Table 5 below shows the WACC ranges we used to calculate the indicative revenue requirements described above.

Table 5: Forecast WACC range

	Low Case (Proposed) WACC %	High Case WACC %
Overall WACC	**8.52%**	**9.11%**
Cost of equity	9.98%	11.02%
Cost of debt	7.55%	7.84%
Gearing	60%	60%
Nominal risk free rate	4.78%	5.17%
Inflation rate	2.50%	2.50%
Debt risk premium	2.77%	2.67%
Market risk premium	6.50%	6.50%
Utilisation of imputation	25%	25%

Cost of debt – 7.55%

Endeavour Energy proposes a trailing average cost of debt using yields over the past ten years on Australian BBB+ corporate bonds with a term to maturity at issuance of ten years. We have used a conservative cost of debt estimate of 7.55 per cent, which is based on the average of the long run estimate of the cost of A and BBB rated debt as estimated by the Reserve Bank of Australia (RBA).[8]

[6] 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.

[7] AER, *Final rate of return guideline,* December 2013, pp. 104-105.

[8] See attachment G - CEG "WACC estimates", Page 27.

For the upper end of our WACC range, we have used a cost of debt estimate of 7.84 per cent, which has been estimated by CEG as the trailing average ten year cost of debt using only Bloomberg data for yields on seven year corporate bonds and regulatory precedent for the method of extrapolating the yield from a seven year yield to an implied ten year yield.

To the extent possible we have had regard to the AER's final rate of return guideline to estimate our indicative rate of return. The AER's final rate of return guideline stated that a trailing average cost of debt is commensurate with the benchmark efficient practice, which is to issue debt on a staggered portfolio basis to manage refinancing risks. We have adopted a trailing average estimate and consider that this approach is commensurate with the NER, as it reflects the benchmark efficient cost of debt for network businesses.

However, the final rate of return guideline also stated that the AER intends to apply transitional arrangements that move all businesses over ten years from the current approach of estimating the cost of debt over a short observation period close to the final decision for a network determination. Based on current forecasts of yields on ten year BBB corporate bonds, this would significantly under compensate Endeavour Energy relative to its stand-alone benchmark efficient costs of debt finance.

As we have noted in submissions to the AER throughout the rate of return guideline consultation process, Endeavour Energy has consistently issued debt on a staggered portfolio basis and prudently managed refinancing risks over the past ten years. The AER's introduction of a debt transition would not allow us the opportunity to recover at least our efficient costs of debt finance which is inconsistent with the revenue and pricing principles outlined in section 7A of the NEL.

We consider that the proposed transitional arrangements for moving to a trailing average cost of debt set out in the AER's final rate of return guideline are inconsistent with the NEL and the NER.

We also note that based on advice received from UBS and provided on a confidential basis to the AER in combined NSW DNSP submissions to the AER's draft rate of return guideline, it would not have been, nor would it now be possible to efficiently re-finance the debt portfolios of the NSW distributors on the basis implied by the AER's transition approach to setting the cost of debt.

The UBS advice suggests that it would be difficult and costly for the NSW DNSPs to refinance their debt portfolios over a 10-40 day period close to the start of the next regulatory control period. UBS suggested:

- If the NSW DNSPs attempted to hedge their debt portfolios (approximately $17 billion in notional debt) over a 10-40 day period, it is questionable whether the Australian swap market would be sufficiently liquid to accept this level of swap contracts;
- Even if the NSW DNSPs were able to hedge their full debt portfolios using interest rate swaps over a longer period (e.g. three months), the transaction would need to be performed behind information barriers to avoid speculators taking advantage of the hedging requirement. However, this would also limit the ability to gain a competitive rate through competition across market participants;
- The costs involved in executing such a large hedging transaction would be significant and the market risk that the NSW DNSPs would have to take on during the execution period would be extraordinarily high. It may be possible for the NSW DNSPs to issue their debt offshore in the US market and then enter into swaps to fix the USD/AUD exchange rate. However, the transaction costs including information requirements, credit rating reports, and advertising would be high;
- Moreover, even though the US bond market is much more deep and liquid than the Australian market a new issuance of $17bn or greater would attract a significant new issuance premium. For example, the recent debt issuance by Verizon (approximately $US49 billion) attracted a 100 basis point new issue premium. There would also be significant lead time (up to three months) before such a transaction could be completed;
- In addition to this, there is insufficient liquidity in the Australian cross currency basis swap market to hedge the exchange rate risk for such a large debt issuance in the US market immediately following such an issuance. Therefore the NSW DNSPs would be exposed to an extraordinarily high level of currency risk over the three month period before the debt issuance could be completed. One standard deviation in the AUD/USD rate over this period could increase the combined debt obligation of the NSW DNSPs

(based on a notional debt portfolio of 60 per cent of forecast RABs) by close to $1 billion. The maximum shift over a three month period is likely to be two standard deviations leading to a potential increase in the combined debt obligation of the NSW DNSPs of close to $2 billion; and

- In both the domestic and offshore scenarios, it is unlikely that the NSW DNSPs or bank counterparties to swap transactions would be able to engage in swap contracts without a Credit Support Annex (CSA) in place. This would expose the NSW DNSPs to even greater funding risks in the event that collateral is called in accordance with a CSA.

The advice from UBS supports the view that the costs of moving away from Endeavour Energy's existing portfolio approach to debt management would have been, and continue to be prohibitively high for the NSW DNSPs, and therefore would result in inefficiently high debt costs.

Cost of equity – 9.98%

In determining our proposed cost of equity of 9.98%, we have had regard to relevant estimation methods, financial models, market data and other evidence.[9] We have also used an approach that leads to a consistent application of financial parameters within the return on equity.[10]

The Sharpe-Lintner CAPM estimates the cost of equity as follows:

Cost equity = risk free rate + βe × [E(rm) – risk free rate]

One approach is to populate the CAPM using an estimate of the forward looking required return on the market based on the historical average realised real return on the market. The AER has termed this approach the "Wright approach".

CEG has applied this approach estimating the required return on the market consistent with NERA's update to the Brailsford et. al. data.[11] NERA estimates the average real realised return on the market, inclusive of the value of imputation credits, from 1883 to 2011 is 8.84%. Adding currently expected inflation of around 2.50% to the historical average results in a realised real return on the market of 11.56%. Given prevailing interest rates in December 2013 (4.34%) this implies a market risk premium of 7.22%. CEG has applied this approach and estimate a cost of equity for a benchmark DNSP of 10.3% to 11.3% (depending on whether an equity beta of 0.8 or 1.0 is used).

Another approach that relies on the historical average realised return on the market is to assume that the market risk premium is constant over time and to use the historical average realised excess return on the market (i.e., in excess of the 10 year risk fee rate) as a proxy for the prevailing market risk premium. CEG has estimated the cost of capital using this approach. For our proposed cost of equity, we use:

- A long term average of yields on ten year Commonwealth Government Bonds of 4.78 per cent as a proxy for the risk-free rate. This is a nominal risk free rate estimate using data from 1883 to 2011 to be consistent with the period over which they calculate our proposed estimate of historical excess returns and an implied market risk premium.[12] (For our high case we have estimated the risk free rate over a ten year period consistent with the benchmark efficient approach to estimating the cost of debt. This provides a risk free rate estimate of 5.17 per cent.
- An equity beta of 0.8 based on long term empirical estimates prepared by Strategic Finance Group Consulting (SFG) and CEG.[13] We note that empirical evidence from NERA consulting using the Black CAPM framework suggests that empirical estimates of the equity beta within the Sharpe-Lintner CAPM framework are likely to understate the return on low beta stocks (i.e. stocks with an equity beta estimate of less than one). NERA's analysis suggests that the best estimate of the cost of equity for a benchmark efficient energy network firm within the Sharpe-Lintner CAPM framework is given by using an equity beta

[9] NER, clause 6.5.2(e)(1).

[10] NER, clause 6.5.2.(e)(3).

[11] See attachment G - CEG "WACC estimates", Page 8.

[12] See attachment G - CEG "WACC estimates", Page 8.

[13] See attachment G - CEG "WACC estimates", Page 8

of one (equivalent to assuming the expected return on the market portfolio is the best predictor of the efficient benchmark cost of equity).[14]

- An excess return to the market portfolio of stocks relative to the risk free rate of 6.5 per cent (often referred to as the market risk premium) based on historical excess returns to stocks above the risk free rate over the period 1883 to 2011.

This approach provides a cost of equity of 9.98 per cent using the CAPM framework. This is very similar to the estimate arrived at following the Wright approach (10.26%). For the purpose of this transitional proposal we have adopted the lower of the two.

We have also had regard to other estimates by CEG of the cost of equity not based on historical averages. These include:

- using the Dividend Growth Model (DGM) to estimate the MRP in order to estimate the capital asset pricing model (CAPM) cost of equity (9.70% to 12.06%)[15];
- using the DGM to directly estimate the cost of equity for the benchmark firm (11.18%); and
- using the Fama French model to estimate the cost of equity for the benchmark firm (11.61%).

We note that most of these estimates fall above the top end of the range used in this submission. Therefore, we consider our cost of equity of 9.98% to be a conservative estimate in the context of all the relevant estimation methods, financial models, market data and other available evidence.

Indicative estimate of forecast capital and operating expenditure

The indicative capital expenditure and operating expenditure for the transitional year is $431 million (2013-14 dollars) and $285 million (2013-14 dollars) respectively. These amounts exclude alternative control services, equity raising costs, and EBSS amounts.

Table 6 below shows annual indicative capital and operating expenditure forecasts in 2013-14 dollar terms over the complete regulatory control period for standard control services. The forecast expenditure profile highlights a reduction in capital and operating expenditure requirements from the current regulatory control period, reflecting our continuing commitment to be prudent and efficient with investments and operations.

Sustained savings

Compared to our current period allowance we are forecasting reductions of 44% in our capital and 5% in operating expenditure programs in real terms (or below the rate of inflation)

It is important to note that at this stage these expenditure forecasts are indicative only. Our proposed expenditure and supporting information for the complete regulatory control period will be detailed in the substantive regulatory proposal, due to be submitted to the AER on 31 May 2014.

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

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Capex	430.7	357.5	309.4	318.7	303.4	**1,719.7**
Opex	284.7	285.9	281.0	275.9	279.3	**1,406.8**

Indicative income tax and depreciation

To estimate the cost of corporate income tax we have used the current corporate tax rate of 30% and assumed a value for imputation credits of 0.25 per dollar of tax paid. This estimate is based on a payout ratio

[14] NERA, *Estimates of the zero-beta premium*, June 2013, pp. 39.

[15] Associated with a theta of 0.35.

for imputation credits of 70%[16] and SFG Consulting's latest estimate of the market value of distributed imputation credits of 0.35[17]. The estimated cost of corporate income tax has been calculated using the AER's PTRM and is outlined in table 3, page 17.

We have estimated revenue allowances for regulatory depreciation based on the AER's preferred approach to calculating regulatory depreciation. This estimates straight line depreciation and divides asset values by the remaining life for each asset.

Remaining lives for each class of asset have been estimated as a weighted average of the remaining life of existing assets, and depreciation of new assets by the standard life for that asset. This average is weighted by the value of assets as at 30 June 2014. We note that this gives greater weight to new assets and therefore extends the remaining life for each class of assets. However, we have not sought to take this into account at this time.

Straight line depreciation is offset by indexation of the RAB within the building blocks framework set out in the NER. This is reflected in the revenue allowances for regulatory depreciation outlined in table 3.

Indicative EBSS amount

The indicative EBSS amount for the transitional year is $95.1 million (in 2013-14 dollar terms). The calculation of this amount and relevant inputs are contained in Attachment G. The EBSS is an incentive scheme that was implemented by the AER as a part of its final 2009-14 determination on Endeavour Energy.

This scheme seeks to provide an ongoing incentive for efficiency improvements over the 2009-14 regulatory period by allowing revenue adjustments to the following transitional and subsequent regulatory control periods.

The EBSS necessitated the establishment of a forecast "controllable opex" amount, against which the actual controllable operating expenditure would be compared to assess the relative rate of change in efficiency improvements. The purpose of excluding some specific categories of opex from the calculation of the EBSS was to ensure that:

- costs are controllable;
- the manner in which the controllable cost allowances were established did not result in a duplication of incentives;
- incentive penalties and rewards were based on a like-for-like comparison; and
- EBSS did not negatively impact the operation of any other incentive arrangement, such as the D-factor or Demand Management Innovation Allowance (DMIA).

In calculating the EBSS carry over for the next five regulatory years, we have made allowances for the matters listed above, in line with the annual regulatory reporting to the AER. Table 7 below sets out the nominal annual revenue adjustments arising from the EBSS over the 2009-14 regulatory period.

Table 7: Forecast EBSS Adjustments

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

Endeavour Energy lodged a pass through application as a result of the retail transaction, but we did not seek to increase revenues to account for the lost synergies. Instead we committed to reducing our overhead costs during the current regulatory period.

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

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

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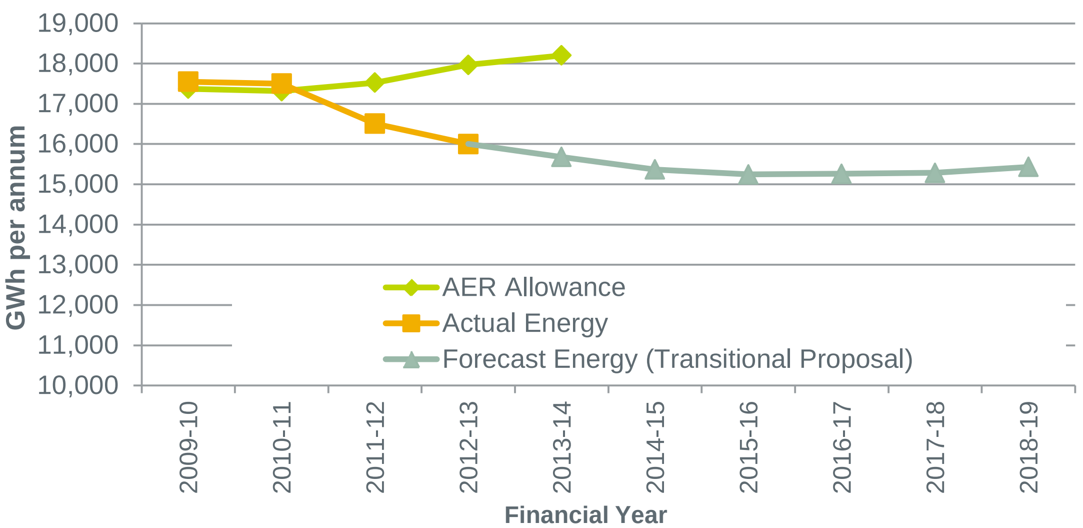
We are committed to reducing costs rather than passing them on to customers, however to ensure that the operation of the EBSS did not impose duplicate penalties on Endeavour Energy, we lodged and the AER subsequently approved, a pass through proposal that was restricted to recognising the retail transaction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

Estimate of consumption

The annual energy consumption across our network is expected to fall by 11% over the 2009-14 regulatory control period with a final year difference between AER approved forecast and our updated energy consumption projection of 14%. Variances in total energy delivered and AER allowances are expected to result in an estimated revenue shortfall of $193 million, despite our ongoing need to invest millions in capital to meet the peak demand that occurs on the hottest days each year.

The forecast reduction in energy consumption is attributable to economic pressures on businesses and manufacturers, our customer response to recent electricity price rises, government-led energy efficiency programs, and the wind-up of the NSW solar bonus scheme and ongoing investment in photovoltaic generators. Our actual and forecast energy consumption is outlined in the following figure.

Figure 6: Energy Volume Forecast



Underlying our energy consumption forecast above, we expect on average, our customers will continue to reduce their use of electricity by 1.6% per annum over the five years commencing 1 July 2014. This expectation is a consequence of the continuing take up of domestic solar panels, the high Australian dollar impacting Australian manufacturing and the continuing impact of double digit electricity price increases from July 2009 to July 2011.

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

Charges for standard control services

Endeavour Energy is committed to alleviating electricity price pressures on customers over the next regulatory control period.

Total revenue for pricing

In the sections above we outline the amount we propose to be the annual revenue requirements for standard control services for the transitional year and subsequent regulatory control period and the inputs used in this calculation.

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In accordance with the approach preferred by the AER in relation to the setting of indicative charges for the transitional year, we have aggregated the costs of providing standard control services and certain alternative control services to calculate a total bundled revenue for the purpose of setting DUOS charges for the transitional year.

This 'bundled revenue' is shown in table 8 below. We propose this to be the amount that will be recovered via DUOS charges for the 2014-15 year. The AER will effectively make a decision, either to accept or otherwise amend, on this proposed amount in its determination for the transitional regulatory control period.

Table 8: Total bundled revenue for 2014-15 pricing

$m; Nominal	2014-15
Annual revenue requirement for standard control services	987.7
Revenue adjustment for type 5-6 metering and ancillary network services[18]	62.6
Total unsmoothed bundled revenue	1,050.3
Total smoothed bundled revenue	**1,007.2**

Our proposed bundled revenue requirement for 2014-15 and the subsequent four years to 2018-19 reflects our commitment to reducing or maintaining our network bill to at or below CPI. We aim to be effective and efficient across the organisation, without compromising the safe and reliable supply of electricity.

In the following sections below we:

- demonstrate how our proposed revenue for 2014-15 is reasonably likely to minimise variations in our network bill between the current, transitional and subsequent regulatory control period and between the regulatory years of the subsequent regulatory control period in line with our commitment to price stability[19];
- provide indicative prices for standard control services; and
- discuss bill impacts for residential and small business customers.

Minimising price variations

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

The National Electricity Rules (NER) require that revenues be smoothed to minimise the difference between required revenues and expected revenue recovery in the final year of the regulatory period (2018-19).[20]The intention is to reduce the potential for network bill shocks between the 2014-19 regulatory years and the regulatory control period that follows.[21]

We have taken customers' preference for pricing stability between years and the requirement for smoothing into account when developing our proposed revenue for 2014-15. The graph at figure 7 illustrates our best estimate of our smoothed revenues that will be required over the 2014-19 regulatory years. The revenue profile has been calculated using the AER's PTRM and ensures that our proposed revenues equal required revenues in net present value terms.

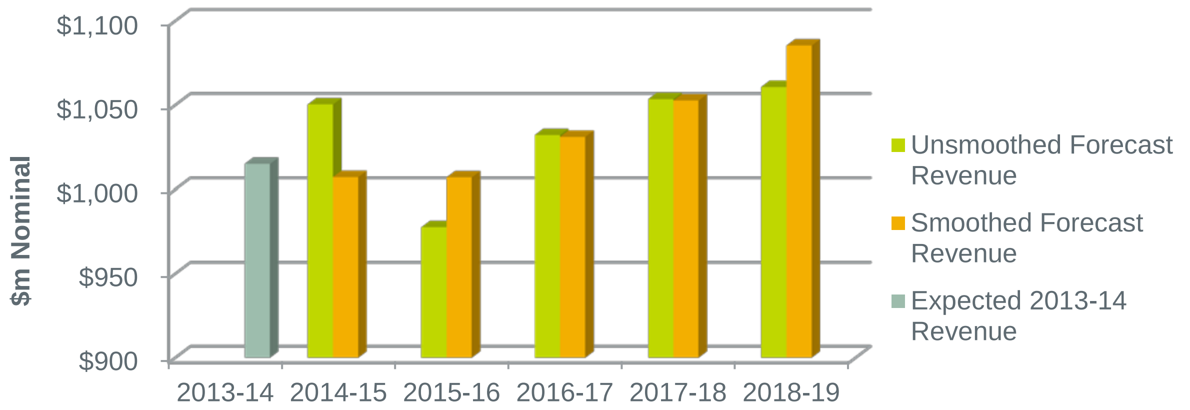
[18] Note: this is the total amount of revenue required to meet the efficient costs of these services. Of this total amount $9.6 million (nominal) will be recovered through existing charges with the remainder being recovered through DUOS for the transitional year.

[19] This is the criteria for the AER's approval as set out in the AEMC's final rule determination, see AEMC, Final rule determination: Economic regulation of Network Service Providers and Price and Revenue Regulation of Gas Services, November 2012, p. 238.

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

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

Figure 7: Indicative annual and smoothed revenue requirements



The 2014-19 revenue requirements include the EBSS carry over amounts which are explained in further detail below, along with other supporting inputs. Expected revenue for 2013-14 is $1,015 million in nominal terms.

As stated in chapter 2, the AER has stated that for the purposes of this transitional proposal it prefers that Endeavour Energy maintain existing classifications for these services (i.e. 2009-10 to 2013-14 classification of services). This is what is reflected in our proposed revenues for 2014-15. From 2015-16 onwards revenues reflect the classifications of services set out in the AER's framework and approach Stage 1 final position paper.

Therefore the drop in revenues from 2014-15 to 2015-16 incorporates the removal of metering and ancillary services related revenues from standard control service revenues. Overall we have aimed to minimise the prospect of bill shocks between 2013-14 and 2014-15 using the smoothing profile outlined above.

As demonstrated in the graph above, we have smoothed revenues so they do not fluctuate greatly between regulatory years. In addition, we have sought to minimise as far as practically possible the difference between smoothed and required revenues in 2018-19. This is consistent with clause 6.5.9(b)(1) of the NER.[22]

Table 9 outlines the real change in revenues each year over the 2014-19 period, which we have used to calculate our proposed revenue for 2014-15. As previously noted, we are striving to contain our share of customers' electricity bill increases to at or below CPI for the next regulatory control period.[23]

Table 9: X-factors used to smooth revenues (% change in real revenues), excluding inflation

%; Real	2014-15	2015-16	2016-17	2017-18	2018-19
Distribution x-factors	3.19%	2.46%	0.11%	0.40%	-0.59%

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

We know that customers value bill stability. As shown in table 10, we expect the proposed smoothed annual revenue requirement, combined with our forecast for energy consumption, will mean customers receive a one-off stepped price reduction followed by a smooth annual real reduction afterwards.

To minimise price variations from the current regulatory period to the transitional year and across the regulatory period we need to take account of changes in energy consumption over the regulatory period.

The following section provides our indicative charges for 2014-15. They are based on our proposed revenue for 2014-15, our latest energy consumption forecasts and our 2013-14 tariff structures as contained in Attachment A1.

[22] In order to manage price variations on behalf of customers, we have sought to manage the one off impact of the inclusion of alternative control service costs (excluding public lighting) in 2014-15 revenues by smoothing the recovery of standard control services into latter years.

[23] Our actual contribution to customers' electricity bills will be affected by several factors including the AER's determination and actual energy volumes for the period.

- if energy consumption falls below our forecast, average distribution network charges will need to increase more than in table 10; or
- if energy consumption rises above our forecast, average distribution network charges would decline below what is in table 10.

Table 10: Change in average distribution charges based on latest energy forecasts (% change, real), excluding inflation

%; Real	2014-15	2015-16	2016-17	2017-18	2018-19
Weighted average change in distribution charges	-2.68%	-1.25%	-1.25%	-1.25%	-1.25%

Note: This forecast does not incorporate alternative control services revenue or changes in the relative contribution of each tariff and/or tariff component to overall distribution revenues over the five-year period. This may change based on energy consumption and pricing decisions each year.

Indicative charges

Table 11 outlines indicative distribution use of system (DUOS) prices for 2014-15 based on our proposed bundled revenue and our latest forecast of energy volumes. This table also outlines the percentage change in average DUOS prices between 2013-14 and 2014-15.

Table 11: Indicative average DUOS for 2014-15

c/kWh; Nominal	2013-14	2014-15	% change
Residential customer consuming 6MWh p.a.	11.76	11.73	-0.24%
Small business customer consuming 26MWh p.a.	9.14	9.11	-0.24%

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

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

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

Typical bill impacts

Table 12 illustrates bill impacts for a typical residential customer and a typical small business customer. This assumes that energy consumption is constant for the customer between 2013-14 and 2014-15. Although metering will not be classified as a standard control service in 2014-15, we have included metering charges in the typical annual bill for 2014-15 because all customers will incur metering related charges in their network bills for both 2013-14 and 2014-15.

Table 12: Bill impact from network charges for typical residential and small business customers (including metering)

$pa; Nominal	2013-14	2014-15	% change
Residential customer consuming 6MWh p.a.	705.6	703.9	-0.24%
Small business customer consuming 26MWh p.a.	2,375.4	2,369.6	-0.24%

BUILDING AND MAINTAINING OUR NETWORK

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Our focus for capital expenditure plans for transitional period and years 2015-2019

Our expenditure plans focus on maintaining a safe, sustainable and reliable network at the lowest practicable charges for customers.

This period follows a significant expenditure program delivered during 2009-14. That expenditure addressed the ageing, deterioration and growth requirements of the network in order to comply with statutory obligations and licence obligations.

Our capex program targets new developments and growth in key areas of North West and South West Sydney.

The lower capex is reflective of the lower demand forecast as well as the initiatives we have implemented to risk manage our capital requirement and therefore contain average increases in our share of customers' electricity bill at or below CPI. Furthermore, we have reduced costs through a stronger focus at both design and delivery stages.

The need for network augmentation has lessened significantly due to improvements in the accuracy of our demand forecasts and a lower demand forecast than approved by the AER for the 2009-14 period. The reduced requirements of the mandated design planning standards has also been reflected in this proposal.

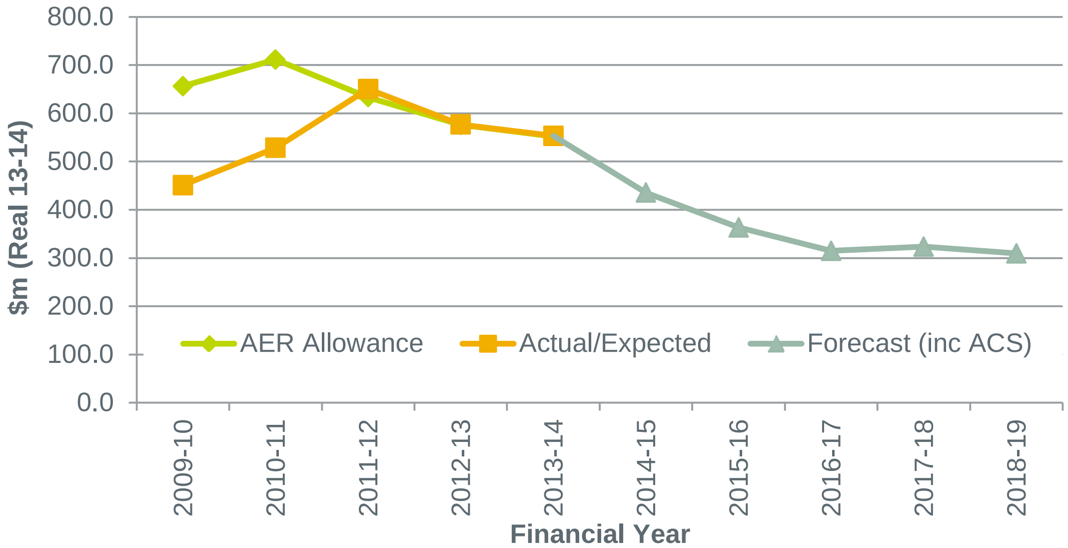
The overall investment portfolio has been optimised using an investment prioritisation model that produces an assessed risk ranking for all proposed capex projects and programs. This has been used in parallel with our planning processes to produce the final capital works program for the regulatory period based on an acceptable level of risk. A zero real cost escalator has been applied to internal labour costs, reflecting our commitment to offset labour cost increases through efficiency improvements.

While we have sought to minimise expenditure, we still need to incur capex 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 last period, we made significant inroads into addressing condition issues. Despite this an ongoing investment program is needed to limit maintenance and breakdown costs and manage safety (including public safety), environmental and other risks.

We are also investing to meet pockets of high demand on our network, including augmentations of the network to meet the needs of new customers particularly in key development areas of North West and South West Sydney. 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 small areas of growing demand or to meet the needs of new customers. Despite the relatively smaller level of investment in capacity, we have taken advantage of demand management to defer capex in a prudent manner wherever possible, and included this in our investment plans.

The proposed expenditure will maintain improvements made during the current period, and continue to meet licence conditions. Figure 8 over the page depicts our capital program trending downwards when comparing actual and forecast expenditure during the current regulatory period. We now have a greater focus on replacing ageing assets rather than growth-related expenditure.

Figure 8: Total Capital Expenditure Forecast 2010-2019



As evident in the figure above, our actual expenditure in the current regulatory control period is below the AER allowance. As discussed on page 9 of this proposal, there were several changes during the current period that reduced energy consumption. In response to this we reviewed our capital program deferring expenditure where appropriate. We also improved our delivery efficiency via our blended delivery approach, which involved using a mix of internal and externally resources. Our forecast capital expenditure is outlined in the table below:

Table 13: Indicative expenditure plans

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
SCS Capex	430.7	357.5	309.4	318.7	303.4	**1,719.7**
ACS Capex (excluding public lighting)	4.7	5.7	5.4	4.9	6.1	**26.8**
Total Capex	**435.4**	**363.2**	**314.8**	**323.6**	**309.5**	**1,746.4**

Capital expenditure drivers

The main purpose of our 2014-19 network strategy is to contain the impact of our share of network bill increases for our customers to at or below CPI. In meeting this objective, and in light of our current period performance, our forecast capital expenditure addresses the following key challenges:

- Maintain a safe, reliable and sustainable network;
- Service growth in demand in the key greenfield growth areas of North West and South West Sydney in the context of falling demand across the broader network; and
- Renew ageing network assets, with a focus on targeted programs to address issues on specific asset classes.

We have sought cost efficiency opportunities in the following three areas:

1. Technical efficiencies

We are committed to understanding the performance parameters of individual assets and asset classes. We invest to achieve the required outcome for the lowest achievable cost. A key aspect of this effort has been the review of asset management strategies in conjunction with Networks NSW. Collaboration with the three NSW DNSPs has helped us better understand how to optimise asset performance.

One area of focus has been in the introduction of cyclic ratings. These allow greater short-term loading capacity of assets. Because the peak demand on our network occurs for relatively short periods of time, by better understanding the short-term capability of our assets we have avoided the need to augment some assets, while still maintaining an appropriate degree of supply security.

Technical efficiencies have also been applied to our maintenance program. The continuation of our failure modes, effects and criticality analysis (FMECA) of maintenance standards has enabled better targeted maintenance expenditure.

Technology has an important role in delivery of technical efficiencies. Over the current regulatory period, there have been price reductions in telecommunications which now make the implementation of technology-enabled networks viable. Over the coming regulatory period we will continue to leverage technologies where they provide proven, cost-effective alternatives to traditional network solutions.

2. Program efficiencies

Our expenditure program is intended to mitigate network risks. By focusing on understanding the specific risks that each project or program of expenditure is intended to address, we are able to target our expenditure at the areas which will have the greatest impact on customer outcomes. Our risk assessment is validated by comparison of like programs run by other NSW network businesses.

3. Delivery efficiencies

Equipment and services necessary to deliver our program are purchased at the best price and the delivery process is planned to make the most efficient use of available resources.

To execute the proposed capital program we have developed a Strategic Delivery Plan. The plan identifies what level of resources are needed to deliver the capital program in a timely and efficient way by using a combination of contractors and employees. A fundamental part of ensuring delivery efficiency has been our introduction of a work process reform to streamline works management.

The pursuit of efficiencies in our capital expenditure program has been carried out in consultation with our workforce. This approach ensures all relevant knowledge on an issue from across the Company is leveraged to obtain the best solution to a problem. The collaborative approach is also in line with our determination to foster a workplace culture which delivers high standards of performance to customers.

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Breakdown of expenditure

The program focuses on expenditure in the drivers outlined below:

Table 14: Forecast Capital Expenditure for Standard Control Services

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Growth	119.2	92.1	61.5	76.2	75.3	**424.2**
Renewal	207.0	195.4	175.5	170.9	156.8	**905.5**
Reliability	13.6	12.3	12.6	12.5	12.9	**63.9**
Compliance	29.7	17.8	23.2	22.8	20.6	**114.0**
Other	6.8	7.2	7.4	7.1	7.2	**35.8**
Non-System	54.4	32.7	29.3	29.2	30.7	**176.2**
Total (SCS)	**430.7**	**357.5**	**309.4**	**318.7**	**303.4**	**1,719.7**
ACS (excluding public lighting)	4.7	5.7	5.4	4.9	6.1	**26.8**
Total Capex	**435.4**	**363.2**	**314.8**	**323.6**	**309.5**	**1,746.4**

- Growth – We augment the network to connect new customers and to ensure that the capacity of the network is adequate to meet forecast demand.

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

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

- Renewal – We invest in the renewal and replacement of assets when the condition of the assets indicates that the continued safe and reliable operation of the assets is no longer economically viable.
- Reliability – We invest to ensure ongoing compliance with reliability performance obligations set out in jurisdictional licence conditions, and in particular to ensure that customers connected to all parts of the network receive at least the minimum specified levels of reliability.
- Compliance – A number of regulatory obligations drive our investment. They include public safety, workplace safety and environmental legislation. Our forecast is to spend an indicative $114 million for the complete regulatory control period on compliance.

- Non-system assets – We invest in assets to support network and corporate functions. This includes expenditure on IT, plant and equipment, and land and buildings.

  Non-system investment has been a focus area of the Networks NSW reforms seeking to leverage the most efficient strategies and practices of the three distribution businesses such as the fleet policy. Further, the non-system capex was subject to prioritisation to ensure that only projects that contribute to the safe and reliable operation of the network were included.

Demand Management

Demand management refers to strategies that reduce peak load on the network. Demand is affected by customer behaviour, the kind of equipment used, and the existence of small-scale generation at a local level. Strategies based on these variables can help postpone or remove the need to augment the network.

We investigate demand management alternatives to major network infrastructure investment. The objective is to determine whether implementation of these alternatives might allow us to avoid or postpone further expansion of the network. We work with customers to manage peak demand to ensure efficient investment in the network.

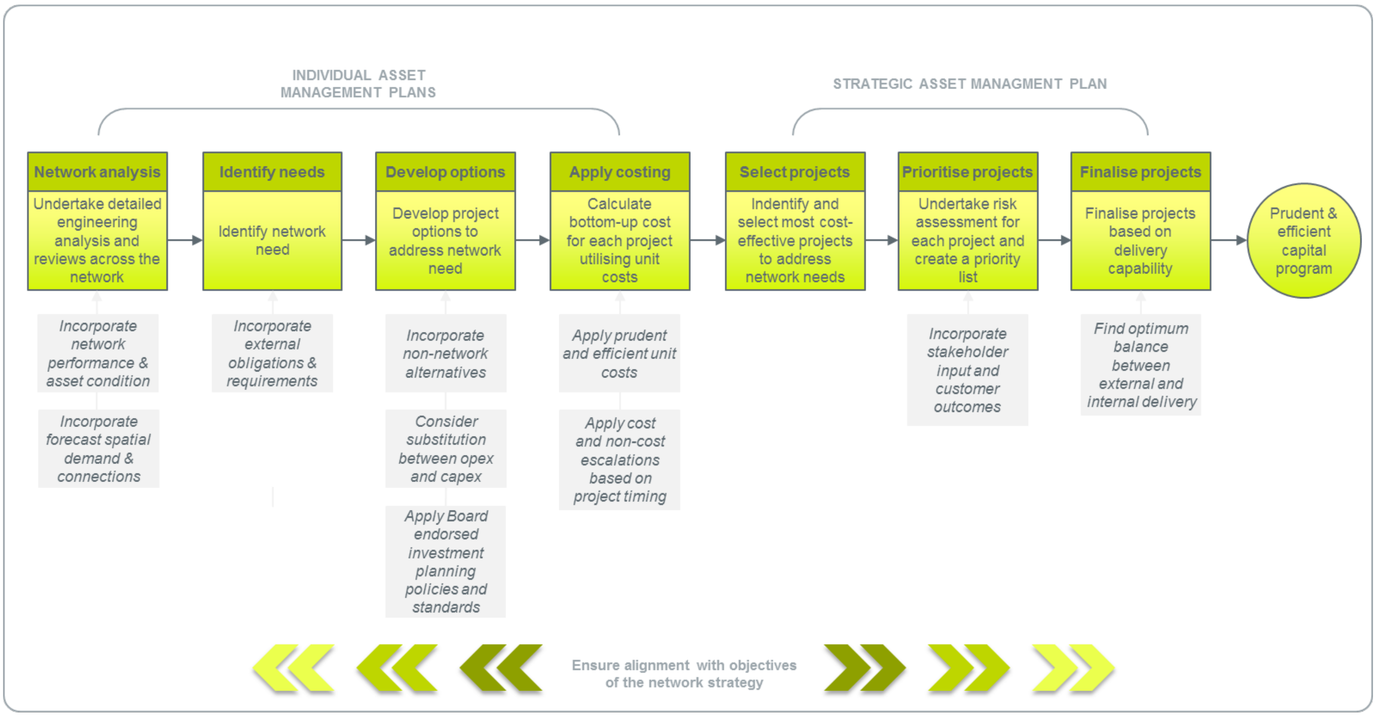
Demand management is a priority for Endeavour Energy. We develop broad-based innovative programs, where they are cost effective and feasible, that encourage customer participation. We expect these initiatives to benefit customers and Endeavour Energy.

The five-year demand management program consists of targeted broad-based projects such as pool pumps on controlled load and power factor correction. It will include DMIA and constraint-driven business as usual projects. In this proposal we have assumed a continuation of the annual DMIA scheme allowance of $0.6 million (in real terms) from the 2009-14 regulatory control period, or $3.0 million over the 2014-19 period.

Capital expenditure forecasting methodology overview

The Strategic Asset Management Plan is the key tool used by Endeavour Energy to ensure that the individual program expenditures are integrated to obtain the maximum network benefit efficiently and sustainably. The key steps in our annual capital expenditure forecasting process are depicted in figure 9 below:

Figure 9: Endeavour Energy Forecasting Process



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As part of the Networks NSW reform program, we have instituted an investment governance process to review and rationalise our capital program.

A prioritisation model is being used for all network projects and programs. The use of an algorithm based on an assessment of risk provides a ranking outcome for investments. This gives both the board and management flexibility to compare investment priorities against the costs and financial risks of doing so.

Our operating efficiency and business transformation journey

Endeavour Energy recognises the impact that changes in operating expenditures have on prices. We have (and continue to) set self-imposed efficiency improvement challenges to meet and manage the impact of changes to our operating environment.

We utilise a base step trend approach to forecasting our operating expenditure requirements. For the 2009-14 regulatory control period we escalated our 2008-09 costs to account for the general movement of inflation and for underlying cost increases relating to commodities and benchmark changes in wages.

We made a cumulative 2% per annum reduction to the labour component of this required operating expenditure forecast as a self-imposed efficiency program. These reduced operating expenditures were included in our forecasts lodged to the AER as part of the initial regulatory proposal in 2008. This efficiency dividend was passed onto customers through lower prices as the AER approved the reduced operating expenditure forecast we submitted.

On 1 March 2011, the sale of the Integral retail business to Origin Energy was completed, triggering a 'Retail project event' as defined in the current AER determination. This inclusion of this nominated pass through event recognised that the retail activities of the three NSW DNSPs provided scale and scope efficiencies. In the absence of these retail businesses a greater portion of our efficient corporate costs would be allocated to our standard control services (by operation of the approved costs allocation method).

The costs transferring to standard control services in the pass through application are set out in the table below. These estimates excluded any transaction or stranded costs associated with the retail project event.

Table 15: Endeavour Energy estimate of cost increases

$m; Nominal	2010-11	2011-12	2012-13	2013-14	Total
Cost to distribution business	4.3	12.4	14.3	16.7	**47.6**

After reviewing the costs presented by Endeavour, the AER concluded in the pass through application decision made by the AER in March 2012 that:

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

Further the AER's decision was to provide for the pass through of the assessed pass through costs being:

- an approved pass through amount of $48.8 million (which includes an adjustment for the time cost of money); and
- that the amount that should be passed through to distribution network users in each regulatory year during the regulatory control period be according to the table over the page:

Table 16: Approved pass through amounts

$m; Nominal	2012-13	2013-14
Annual pass through amount	33.1	15.7

As noted earlier in this proposal, although Endeavour Energy's proposal to recover the corporate costs being reallocated to standard control services was approved, we did not increase our charges. Rather, we targeted (and achieved) efficiency gains across all aspects of our business throughout this current regulatory control period to offset the increased share of corporate overheads being allocated to standard control services.

Further, we note that reductions in operating costs reported against unregulated activities were not merely reallocated to standard control costs. Rather these were true reductions in our operating costs across the business with net operating cost decreases in 2011-12 and 2012-13 totaling over $60 million.

Our focus of operating expenditure plans for the transitional period and years 2015-2019

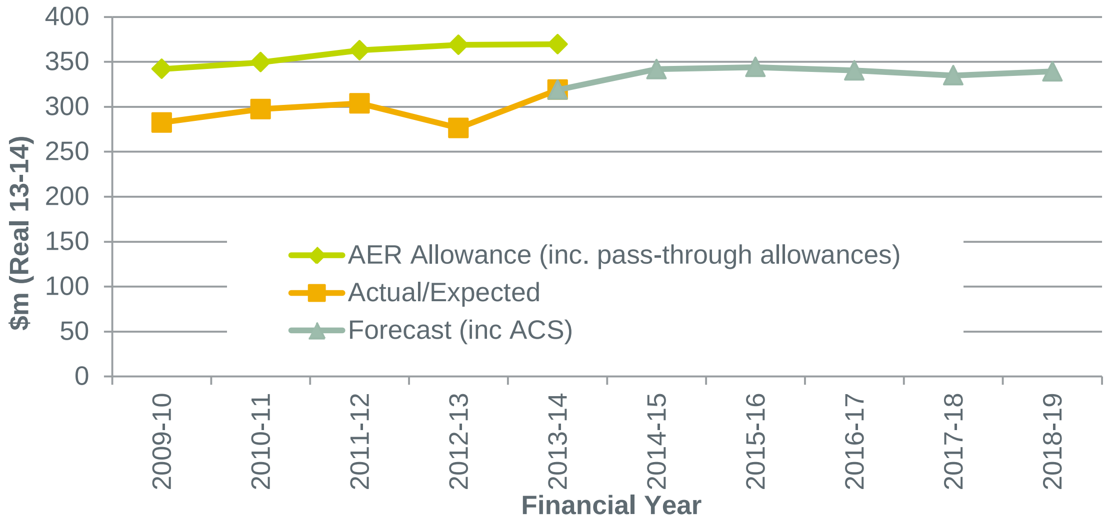
The operating expenditure plan incorporates significant productivity and efficiency gains. It is driven by a combination of our internal efficiency drive and Networks NSW cost reduction initiatives.

Our efficiency programs initially delivered substantial short-term savings at the beginning of the current regulatory period. This is demonstrated by the operating expenditure efficiency saving of approximately $54 million we achieved in the first year of the current regulatory period. We also sought efficiencies to deliver savings over time and expect to achieve savings totalling an estimated $300 million over the current regulatory period.

As discussed on page 10 of this proposal, these savings were the result of a three year efficiency program across the company followed by the Network Reform Program and supporting a reduced capital program in a more efficient manner through our blended delivery approach.

Our forecast operating expenditure seeks to maintain this efficient level of expenditure. The savings made in the current regulatory period were in excess of the annual reduction of 2% of labour opex we committed to making at the time of our last proposal, which was incorporated into the AER allowance as outlined in the figure below:

Figure 11: Operating Expenditure Forecast 2010-2019[24]



[24] An explanation of the changes between the 2012-13 base year and 2014-15 year can be found on page 35 of this proposal

Table 17: Indicative expenditure plans

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
SCS Opex	284.7	285.9	281.0	275.9	279.3	**1,406.8**
ACS Opex (excluding public lighting)	57.1	58.3	59.3	58.9	60.0	**293.7**
Total Opex	**341.8**	**344.2**	**340.3**	**334.8**	**339.4**	**1,700.5**

The forecast opex primarily contains expenditure on maintenance and corporate support functions to maintain current network performance. As a result, the opex profile is smooth with no substantive increases between years. This is in line with our determination to reduce our costs and increase efficiencies to provide better value for our customers.

Operating expenditure drivers

Our operating expenditure for the transitional year and following period is designed to support the network and comply with our legislative obligations. A number of efficiency programs have been developed within the current period that will continue into the next period to ensure we deliver our services at the lowest cost to customers. Our operating expenditure is driven by the following factors:

1. Regulatory and legislative obligations, changes to these obligations or the introduction of new obligations. These obligations stem from:
   - obligations under the Electricity Supply Act 1995 (NSW) and our operating licence;
   - obligations under the National Electricity Law and National Electricity Rules;
   - general legal obligations that have specific impacts on the electricity industry such as work health and safety obligations; and
   - the governance and financial obligations associated with being a state-owned corporation.
2. The particular environment in which we operate, and changes to this operating environment since the last determination, including:
   - the current condition of our assets;
   - the inherent relationship between existing assets and operating expenditure and the impact on operating expenditure from future capital investments;
   - the expected cost of inputs (for example, labour) in the 2014-19 years; and
   - market factors that impact on financial parameters relevant to the forecasting of specific operating expenditure costs. For example, insurance premiums or debt raising costs.

As described later in this section, we apply a ‘base-step-trend’ approach to forecast our operating expenditure. The specific ‘step’ and ‘trend’ factors included in our forecasts as evident between the 2012-13 base year and 2014-15 in the graph above are described in further detail below:

- Cost escalation – In accordance with a base-step-trend approach we have trended our base year opex to reflect nominal cost pressures from input labor, materials and contractors. For the purposes of our transitional proposal we have assumed general cost increases in line with the forecast rate of inflation;
- Vegetation management – For 2014-19 an increase in annual vegetation management costs compared to our base year arises due to observed improvements in contract performance from our market providers. This is consistent with our ongoing focus to achieve required program compliance for this critical risk management function.

  However, it is anticipated that following the step change to address these conformance issues vegetation management costs will be downwards trending in real terms over the 2014-19 period;

- Retail dis-synergy costs – as foreshadowed in Endeavour Energy's pass through application approved by the AER in March 2012, the sale of the retail business results in the regulated network services being allocated a greater share of the (reduced) residual corporate and overhead costs. As the 2012-13 financial year was the last year in which we provided any retail support services, the 2013-14 financial year is the first year in which these dis-synergy costs are fully crystallised. As discussed earlier, we implemented opex savings programs in prior years to off-set the impact of the dis-synergy costs; and
- Capital prioritisation and efficiency program costs – as noted earlier in this chapter, lower capital spending will create an increase in our operating expenditure compared to our base year. This increase reflects costs of redundancy and other costs as we reduce our labour force, reallocation of some overheads from capital to operating costs and the need to undertake some additional maintenance expenditure.

  We expect the reductions in our capital program will deliver savings in excess of these operating cost increases. It is anticipated that once the step change to address these considerations has been addressed that maintenance costs will be downwards trending in real terms over the 2014-19 period

In addressing these factors, we have incorporated significant network reform savings into our forecast expenditure. These savings are driven by a suite of initiatives which were outlined in the overview section of this proposal. We have also delivered significant savings during the current regulatory control period to off-set some of these step changes, in particular the dis-synergy costs associated with the sale of the retail business and the completion of the Transitional Service Agreement (TSA).

Breakdown of expenditure

This program is highlighted by expenditure in the following areas:

Table 18: Forecast Operating Expenditure for Standard Control Services

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Network Operating Costs	24.9	25.3	24.1	23.3	23.4	**120.9**
Inspection	29.7	30.1	29.5	28.7	28.8	**146.8**
Maintenance & Repair	62.6	60.2	59.5	57.9	58.3	**298.5**
Vegetation Management	68.0	69.0	67.7	65.8	66.0	**336.5**
Emergency Response	49.8	50.9	50.1	51.1	53.5	**255.3**
Network Maintenance Operating Costs	20.8	21.0	20.9	20.7	20.8	**104.2**
Customer Service	5.7	5.8	5.7	5.5	5.5	**28.1**
Other Operating Costs	19.5	19.9	19.6	19.1	19.1	**97.3**
DMIA	0.6	0.6	0.6	0.6	0.6	**3.0**
Debt Raising Costs	3.0	3.2	3.3	3.3	3.4	**16.1**
Total SCS Opex	**284.7**	**285.9**	**281.0**	**275.9**	**279.3**	**1,406.8**
ACS (ex Public Lighting)	57.1	58.3	59.3	58.9	60.0	**293.7**
Total Opex	**341.8**	**344.2**	**340.3**	**334.8**	**339.4**	**1,700.5**

A description of the types costs incurred under each of these categories is explained below:

- Network operating costs – This category of costs cover operating costs required to manage the network such as: staffing of the control centre; operational switching personnel; outage planning personnel; and provision of authorised distribution personnel. It also covers support activities directly related to the network such as: demand forecasting; procurement, logistics and stores; information technology (IT) costs directly attributable to distribution operation; and land taxes.
- Inspections – Routine asset inspection and condition monitoring activities include field and aerial inspection of overhead distribution assets (poles, pole top structures, conductors, substation structures, transformers, high and low voltage switchgear, and other distribution electrical equipment); powerline to ground and vegetation clearances; thermography of powerline and substation structures; and non-destructive testing of power transformers and switchgear.
- Maintenance and repair – This category covers all maintenance and repair activities on network assets. But excludes fault and emergency repairs and restoration of supply for planned and unplanned interruptions which is categorised as emergency response. Components include maintenance and repair of distribution powerline equipment, damaged or inoperable switchgear, distribution and zone substations, and customer service mains;
- Vegetation management – This work, mainly carried out by external contractors, reduces safety hazards and interruptions to supply on our overhead electricity network. Compliance with this policy is a critical control measure associated with management of bushfire risk. Vegetation management must be done regularly to ensure a reliable and safe electricity supply. It must also be done in a way that is sensitive to environmental and community issues;
- Emergency response – This covers fault and emergency repairs and restoration of supply for planned and unplanned interruptions caused by events such as storms, equipment failures, acts of vandalism, and vehicle collisions. When notified of an interruption to customer supply, Endeavour Energy promptly dispatches field employees to deal with the fault;
- Network maintenance operating cost – This cost category covers other activities that are required to support the maintenance of the network itself such as: fire mitigation (excluding vegetation management); field training; and any other cost required for the safe operation and maintenance of the distribution network;
- Customer service – This activity includes call centre and operational activities relating to customer interaction and reporting on issues such as: distribution faults and safety hazards; complaints about the quality and reliability of supply; queries on new connections, disconnections and reconnections; and queries on improving power factor or load factor; and
- Other operating costs – This category includes all other costs that are incurred in the provision of standard control services but are not related to the operation of the network itself such as, operating tools and equipment purchases, billing and revenue collection and regulatory costs. .

Operating expenditure forecasting methodology overview

To comply with the NER and to ensure that the nature of each cost category is appropriately accounted for in preparing the total forecast, we have used the following approach:

- The base step trend revealed cost approach will be applied to the majority of Endeavour Energy's network maintenance activities, other operating costs and direct and indirect overhead forecast operating expenditure. We use a 2012-13 base year adjusted where necessary for one-off or non-recurrent expenditure to forecast expenditure. We forecast operating expenditure at the category or activity level where appropriate; and
- Other operating expenditure (including non-network alternative programs, self-insurance and debt raising costs) is forecast using benchmark costs or individual project forecasts where appropriate.

We have used the actual operating expenditure for the financial year 2012-13 as the starting operating expenditure in developing the 2014-19 forecast. This financial year is the fourth year of the current regulatory period and is used because it is the latest actual operating expenditure data available at the time of preparing the forecast.

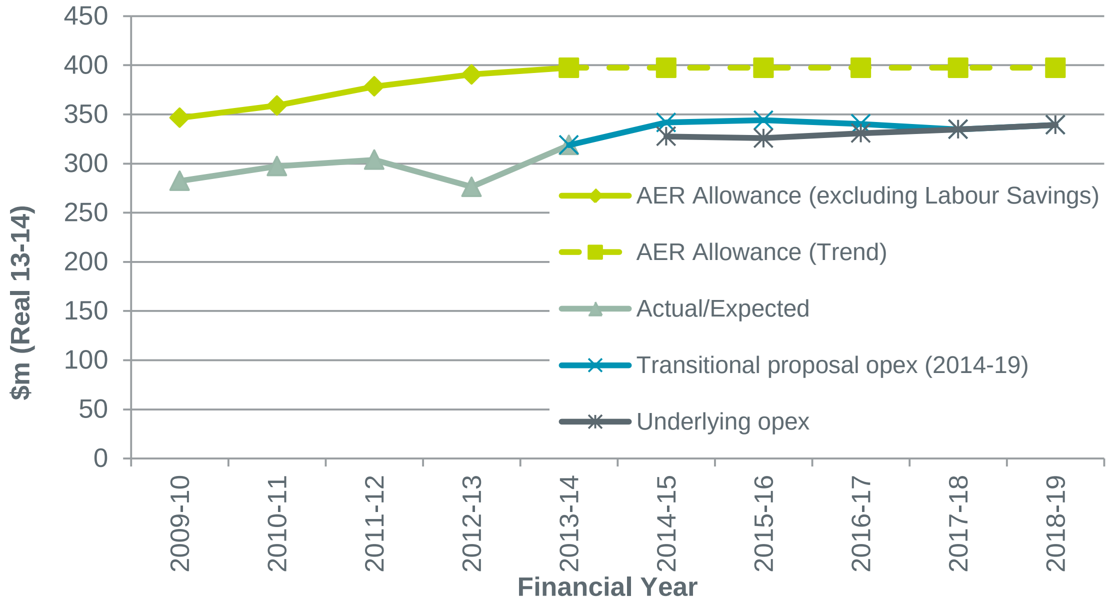
The base year represents the actual operating expenditure that had been properly allocated to standard control services in accordance with the principles and policies set out in Endeavour Energy's approved cost allocation method applicable to the 2009-14 regulatory control period. The base year total actual operating expenditure has also been adjusted for one-off expenditure to ensure the base amount reflects recurrent expenditure only.

Endeavour Energy has a commitment to achieving sustainable operating expenditure savings that will benefit our customers in the longer term.

Figure 12 below sets out the AER approved opex allowance for 2009-14 exclusive of our commitment to achieve a 2% annual improvement in labour efficiencies over the same period. This has then been trended forward into the 2014-19 period and compared with our actual and forecast operating expenditure over the two regulatory periods 2009-19 to demonstrate the impact of our various efficiency programs. The underlying opex depicted in figure 12 is our proposed opex for the 2014-19 period after removing the transition costs incurred to achieve our above mentioned capital efficiency program.

The key observation from figure 12 below is that Endeavour Energy has succeeded in maintaining operating expenditure reductions despite increases of costs from the reallocation of corporate costs and increases in vegetation management costs. As a consequence our customers will receive the benefit from more than $50 million in annual operating expenditure costs being removed from the charges they pay.

Figure 12: Operating Expenditure Forecast 2010-2019 compared to allowance (without savings)



Public lighting services

In accordance with cl 11.56.3(j) of the transitional rules, public lighting prices for the final year of the current regulatory period have been escalated by CPI to calculate transitional year prices. A listing of these prices can be found in Attachment E.

As public lighting services are subject to a cap on prices, we are required to provide an indicative estimate of demand. Demand for public lighting services is best estimated by forecasting the number of lights that will be provided by Endeavour Energy during the regulatory period. Indicative estimates of demand for the transitional year can be found in the table below:

Table 19: Indicative estimate of demand for Public Lighting services

	2014-15	2015-16	2016-17	2017-18	2018-19
Number of Lights	201,519	204,743	208,019	211,348	214,729

Newly classified alternative control services

Type 5-6 metering services

Metering services cover the provision, installation, reading, maintenance and related data services. The AER has unbundled the charges for some metering services (type 5 and type 6) from standard control services, to promote competition, facilitate customer choice and remove any subsidies between existing services.

For type 5-6 metering installations located our network area, we are required to:

- ensure that all relevant connection points are metered to the defined standard;
- develop a Meter Asset Management Plan (MAMP) for the maintenance of metering installations and for the MAMP to be approved by the Australian Energy Market Operator (AEMO); and
- 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 metering data services.

Endeavour Energy's existing meters are predominantly basic accumulation (type 6) meters, so the issue of significant cross-subsidisation amongst customers due to technology choice is not significant. Few customers have type 5 meters, which are not smart meters but do capture more detail about usage than type 6.

During the F&A process we raised some concerns about whether unbundling might lead to customer confusion, but we have nonetheless undertaken a process to separate metering services from standard control services, and develop cost reflective prices.

The costs needed to deliver metering services for type 5-6 comprise of operating and capital costs. In addition to the capital costs of meters installed after 1 July 2014, capital costs also relate to the return on and return of the meter asset base that existed prior to 1 July 2014.

Operating costs

The total operating costs for metering services comprise of costs for maintenance, meter reading and meter data services. The total indicative operating costs of providing metering services for the transitional year is $19.8 million and the details are shown in table 20 over the page:

Table 20: Forecast average annual operating costs type 5-6 metering

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Total type 5-6 metering operating costs	19.8	19.6	19.7	19.5	19.7	**98.3**

Capital costs

The capital costs represent the cost of financing the capital value of the meters installed at customer premises (the return on capital) as well as the return of this capital (regulatory depreciation).

Up until the 30 June 2014, all metering assets form part of Endeavour Energy's total Regulated Asset Base (RAB) for standard control services. As a consequence of the change in classification by the AER of type 5-6 metering services, we will need to separate the value of our existing types 5-6 metering assets from the standard control services opening RAB value as at 1 July 2014.

The value required to be deducted from the RAB for standard control services is $22.1 million as shown in table 21 below:

Table 21: Indicative Starting Value of Metering Services RAB at 1 July 2014 ($M)

$m; Real 13-14	2014-15
Customer metering and load control	20.5
Information & Communication Technology	0.2
Furniture, fittings, plant and equipment	0.2
Motor Vehicles	0.1
Buildings	0.8
Land (non-system)	0.5
Other non-system assets	0.0
Total metering services RAB value	**22.1**

We forecast a total capital expenditure of $4.7 million for the transitional year. The annual forecast capital expenditure is shown below:

Table 22: Forecast average annual capital costs type 5-6 metering

$m; Real 13-14	2014-15	2015-16	2016-17	2017-18	2018-19	Total
Total type 5-6 metering capital costs	4.7	5.7	5.4	4.9	6.1	**26.8**

The total forecast capex is made up of two components and these are:

- the provision of new metering assets in response to customer demand at new or upgraded premises, or where the customer elects to change the meter type installed(the installation work is provided in a contestable environment, and therefore these costs are not included), and
- the reactive and proactive replacement of meters that have failed in service or form part of Endeavour's Meter Replacement Plan.

Ancillary network services

The AER has proposed to create a group of services called ancillary network services to capture non-routine services provided to customers on an as-needed basis. Examples of such services include providing customer design related information, special meter readings and after hours service provision.

This class of service is currently grouped as "miscellaneous and monopoly" services. It will also include incidental services and potentially also new distribution services which Endeavour Energy has identified as being necessary to satisfy the National Energy Customer Framework's requirements.

As the nature of service involves work on or in relation to parts of Endeavour Energy's distribution network, the AER decided to classify ancillary network services as direct control services. The AER decided that these services should be further classified as alternative control services, as the costs of such services can be directly attributed to an individual or small group of customers.

In giving effect to the change in classification for each of these services, our consultation with the AER has indicated that the transitional rules guide the implementation of these changes. We have prepared our proposal based on the AER's interpretation of the transitional rules, which is set out below.

Approach for the transitional year

As discussed in Chapter 2, for the 2014-15 year, the transitional rules require that we:

- classify our services as per the AER's framework and approach paper published in respect of the subsequent regulatory control period (cl. 11.56.3(a)(1)); and
- allocate our costs for the transitional year as if it were the last year of the current regulatory control period (cl. 11.56.3(i)).

Essentially, whilst type 5-6 metering and ancillary network services have been reclassified, the costs relating to these services remain allocated to standard control services. The AER's preferred approach specifies that:

- for the existing group of "miscellaneous and monopoly" fees (a subset of the reclassified ancillary network services) the existing prices for these services will be escalated by CPI;
- for services currently provided as standard control services that are not separately recovered from customers prices for these services for the transitional year will be zero as the AER have formed the view that the costs for these services will continue to be recovered through DUOS for the transitional year; and
- for services that were not provided during the current period cost reflective prices will be determined. It should be noted that for Endeavour Energy, there are no "new" services that have not been previously provided in some form as part of our existing miscellaneous and monopoly services or standard control services in general.

These costs will be allocated to alternative control services from the 2015-16 period onwards. At the time of our substantive proposal we will therefore propose fully cost reflective prices for all of these services.

We have prepared this proposal by separating the costs of the reclassified services from standard control costs for the whole forthcoming regulatory period. A revenue adjustment has been made to the transitional year for the costs of the reclassified services that are to be recovered from standard control services revenue for that year. We have calculated this adjustment using the AER's PTRM, at Attachment A3.

The adjustment made to unsmoothed standard control service revenues for the 2014-15 year based on the inclusion of these type 5-6 metering and ancillary network services costs is outlined in the table over the page:

Table 23: Breakdown of revenue adjustment for newly classified alternative control services

$m; Real 13-14	2014-15
Return on capital	1.9
Return of capital	2.3
Operating expenditure	57.1
Cost of corporate tax	-0.2[25]
Total	**61.1**

This revenue adjustment has therefore been included in the smoothing of our revenue requirements over the 2014-19 regulatory control period which is described in Chapter 3 of this proposal.

As described in Chapter 2, it is our understanding that consistent with the treatment of the costs in 2014-15, any necessary adjustment to our metering or ancillary network services expenditure for the transitional year will be applied to DUOS prices over the remainder of the substantive period.

Indicative estimate of demand

As type 5-6 metering services are subject to a cap on prices, we are required to provide an indicative estimate of demand. Demand for metering services is best estimated from metering customer number forecasts. These estimates can be found in the table below:

Table 24: Indicative estimate of demand for Metering type 5-6 services

	2014-15	2015-16	2016-17	2017-18	2018-19
Type 5-6 Metering Services	1,350,134	1,363,708	1,375,405	1,386,760	1,398,785

Similarly, as ancillary network services are subject to a cap on prices, we are required to provide an indicative estimate of demand. Demand for ancillary network services is best estimated by forecasting the volume of services to be provided during the regulatory period. Our volume calculations were predominantly based on data extracted from the various billing systems that we currently use for invoicing miscellaneous and monopoly fees. In most cases the volumes were derived based on the average of three or four years of historical data adjusted for growth (if applicable).

For new fees the volumes were derived based on internal analysis. Please refer to Attachment F for a listing of our prices and forecast volumes per service.

Indicative prices for transitional year

As outlined above, for ancillary network services that are priced in the current period, CPI escalation is to be applied. Our price list has been prepared in accordance with this rules requirement and can be found in Attachment F.

[25] A negative tax impact can occur when the residual technical life of the asset is less than the residual tax life. This scenario is analogous to accelerated tax depreciation, and is not unexpected when developing building block revenue for a single asset class.

COMPLIANCE AND REPORTING ARRANGEMENTS

06

In this section we propose our reporting arrangements on the recovery of designated pricing proposal charges and jurisdictional schemes amounts such as the Climate Change Fund. We also address how we intend to comply with the revenue cap control mechanism that will apply to our standard control services.

Jurisdictional schemes are specified in the rules or by the AER and refer to programs established under state legislation. These programs require that we pay certain amounts to a person or into a fund established by NSW legislation. The rules allow us to recover these amounts from customers as part of their electricity bills.

Reporting on recovery of designated pricing proposal charges and jurisdictional scheme amounts

Designated Pricing Proposal Charges include the transmission-related charges payable to TransGrid, avoided Transmission Use of System (TUOS) charges payable to certain generators, and inter-distributor payments.

Jurisdictional scheme amounts are amounts which Endeavour Energy is required to pay under jurisdictional requirements. They have been recognised as amounts which may be recovered under the rules as part of Endeavour Energy's pricing proposal. There are currently two jurisdictional schemes relevant to Endeavour Energy recognised in the rules. The first is the NSW Solar Bonus Scheme[26]; the second is the NSW Climate Change Fund.

Endeavour Energy proposes that the AER should use the same overs and unders account mechanism to report the recovery of designated pricing proposal charges and jurisdictional scheme amounts as has been used to report TUOS charges and the Climate Change Fund payments during the 2009-14 regulatory period.

The proposed overs and unders account mechanism ensures that these charges and scheme amounts are passed through to customers in a manner that ensures that they pay no more or less than required.

The mechanism also includes an adjustment on outstanding balances that is consistent with the allowed rate of return. The over or under recovery calculated by this mechanism is passed through to customers via an adjustment in annual prices. It will be reported in the pricing compliance model submitted to the AER as part of the annual pricing proposal.

The proposed mechanism is included in Attachment B to this transitional regulatory proposal.

Demonstration of compliance with control mechanism for standard control services

The control mechanism to apply to standard control services for the 2014-19 years is a revenue cap. The AER's proposed formula for the revenue cap is set out in the framework and approach paper. We have included the AER's approach and our proposed demonstration of compliance in Attachment B to this transitional regulatory proposal.

[26]During the 2009-2014 period all payments made under the NSW Solar Bonus Scheme have been recovered by NSW DNSPs through payments to and from NSW Climate Change Fund.

ATTACHMENTS

07

Item No	Description
A1	Completed Post Tax Revenue Model – Transitional Proposal
A2	Completed Post Tax Revenue Model – Exclusive of Metering and ANS
A3	Completed Post Tax Revenue Model – Inclusive of Metering and ANS
B	Compliance Model with control mechanisms for Standard Control Services
C	Completed Roll Forward Model
D	WACC report (CEG)
E	Public Lighting price list
F	Ancillary Network Services price list
G	Application of incentive schemes (EBSS)
H	Connection Policy
I	Approach to reclassified Alternative Control Services

GLOSSARY

08

Term	Definition
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
CAPEX	Capital Expenditure
CPI	Consumer Price Index
DMIA	Demand Management Innovation Allowance
DNSP	Distribution network service provider
DUOS	Distribution Use of System
EBSS	Efficiency benefit sharing scheme
FMECA	Failure modes, effects and criticality analysis
GWh	Gigawatt Hour
IPART	Independent Pricing and Regulatory Tribunal of NSW
MRP	Market Risk Premium
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NMI	National Metering Identifier
NPV	Net present value
NUOS	Network Use of System
Pass through event	Per the Transitional Rules
PTRM	Post tax revenue model
RAB	Regulatory asset base
Regulatory proposal	Per the Transitional Rules
Rules	National Electricity Rules
SAMP	Strategic Asset Management Plan
SCI	Statement of Corporate Intent
STPIS	Service target performance incentive scheme
Transitional Rules	Division 2 of Chapter 11 transitional provisions for NSW/ACT distribution network service providers for the economic regulation of NSW distribution services for the transitional regulatory control period 1 July 2014 to 30 June 2015
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital
X factor	(%) change in real revenues between regulatory years