Revised Regulatory Proposal

1 JULY 2019 – 30 JUNE 2024

Endeavour Energy

This document is Endeavour Energy's revised Revenue Proposal submitted to the Australian Energy Regulator (AER) under Rule 6.10.3 of the National Electricity Rules (the Rules) on 8 January 2019.

This revised proposal details our proposed revisions to our operating and investment plans for the period from 1 July 2019 to 30 June 2024 in response to the AER's draft decision. It follows the AER's review of our initial proposal lodged on 30 April 2018 and the subsequent AER draft decision of 1 November 2018.

In this revised proposal we either confirm or update our proposal in response to the AER's draft decision and ongoing engagement with customers and stakeholders.

Following the lodgement of this revised proposal, we will continue to work with the AER, customers and stakeholders to help inform the AER's decision-making to deliver a final revenue determination that is in the long term interests of the 2.4 million people across the one million households and businesses we serve in Sydney's Greater West, the Blue Mountains, the Southern Highlands, the Illawarra and the South Coast.

The forecasts and projections included in this revised proposal are based on information available at this time. Although reasonable endeavours have been made to ensure accuracy at the time of writing, we note that methodologies, legislation, judicial decisions, regulatory guidance and prevailing market conditions are subject to change.

To enable comparisons of trends and costs over time, forecast and historical expenditure is expressed in real terms (excluding inflation) in 2018-19 dollars unless otherwise indicated, while the Regulated Asset Base (RAB) and revenue 'building blocks' are presented in nominal terms (including inflation) consistent with the AER's Post Tax Revenue Model (PTRM).

Table of contents

Foreword

Every five years, we work with customers and stakeholders to prepare investment plans to build, operate and maintain our vast electricity network. These costs make up about 30 percent of the average residential electricity bill, so it is vitally important that every dollar we spend aligns with our customers' priorities.

From extensive engagement with stakeholders and consumer representatives over the past three years, we know that affordability remains the number one concern for our customers, but not at the cost of reliability or safety. That is why our revised plans for the 2019-24 period accept the bulk of the AER's draft decision. We will also apply the new rate of return instrument. In doing so, we will deliver greater price reductions for consumers than those originally proposed and determined in the AER's draft decision. If accepted, this revised proposal would see:

- average residential customers pay approximately $66 less on their annual bill in FY24 than they do today in real terms
- average small business customers pay about $113 less on their annual bill in FY24 than they do today in real terms

Adjusted for inflation, this means that six years from now an average residential customer would pay about $10 less for the network component of their bill (in FY24) and an average small business would pay $17 less.

This is a significant positive step for the one million customers within our network that already pay the lowest network charges in NSW and will continue to do so for the next five years locking in a decade of no real price increases, whilst at the same time responding to significant growth that is occurring within our supply area.

This revised proposal has been possible due to the collaborative and respectful relationship developed between the AER, Endeavour Energy and its many stakeholders and customers. Constructive discussion between all parties has been a key factor in shaping our expenditure forecasts and organisational focus, and we thank all of those who have participated for your valued assistance, support and feedback in helping us prepare this final five-year revenue proposal.

It also reflects the necessary improvements we have made to become a more agile business under our new owners, who bring a strong efficiency focus that is enabling us to respond quickly to the dramatic changes in the industry. Growth is a key distinguishing feature for Endeavour Energy, as is the need to invest now to accommodate increasingly levels of distributed energy resources across the network in the future.

In publishing this revised proposal, we are now seeking further input from our stakeholders and customers before our plans are finalised with the final determination by the AER in April 2019. We set out a snapshot of our Revised Regulatory Proposal below, which we explain in more detail in the remainder of this document.

I encourage you to read the following pages to find out more about what is planned, what this means for your future electricity bills, and how you can have your say on how you want us to meet your electricity needs and operate in the future.

Tony Narvaez

Chief Executive Officer
Endeavour Energy

Our revised proposal at a glance

Standard Control Services ($M, Real 2018-19)	Proposal	Draft Decision	Revised proposal	Revised Proposal Commentary
Operating expenditure (excluding debt raising costs)	1,485.5	1,452.0	1,452.9	Accept AER methodology[1].
Net capital expenditure (plus disposals and excluding equity raising costs)	2,158.1	1,700.3[2]	1,739.6	Updated to include the Western Sydney Aerotropolis that was originally proposed to be a contingent project.
Capital contributions	534.7	709.8	709.8	Accept AER draft decision
Opening Regulatory Asset Base	6,512.1	6,512.1	6,529.5	Accept AER methodology
Closing Regulatory Asset Base	7,293.6	6,873.2	6,906.2	Accept AER methodology
Revenue Requirements $M, Nominal				
Return on capital (%)[3]	6.11%	5.71%	5.74%	Updated for the final Rate of Return Instrument
Regulatory depreciation	504.3	531.5	529.6	Accept AER methodology
Revenue adjustments (incentive schemes and 2014-19 remittal)	-1.5	9.0	-11.8	Accept AER methodology
Corporate tax allowance	192.1 Gamma: 0.400	166.5 Gamma: 0.500	134.5 Gamma: 0.585	Updated for the final Rate of Return Instrument
Maximum allowable revenue (MAR)[4]	3,891.6	3,731.8	3,686.6	Updated for the above
Revenue x factors (%)	We accept the smooth profile in AER's draft decision. We have proposed a similar profile for our revised revenue proposal.			
Energy consumption (GWh)	We accept the AER's draft decision to accept our proposed forecasts for energy consumption, customer numbers and maximum demand.			
Customer numbers				
Maximum Demand (MW)				

[1] For several aspects of the AER's draft decision we accept the methodology noting that updates are required to reflect the latest available information like FY18 actual performance. We also note that the AER will make further updates in the final decision e.g. latest actual CPI data and applying the agreed cost of debt averaging period.
[2] This is the AER's intended draft decision correcting for a modelling error in the treatment of disposals.
[3] As a forward debt curve is estimated resulting in annual variations in the WACC this is the average WACC over 2019-24.
[4] Figures presented in Net Present Value (NPV) terms

Key Decisions	Proposal	Draft Decision	Revised proposal
Service classification	Accept the AER's 2019-24 Framework and Approach (F&A) paper.	Accepted with amendment to 'common distribution services' definition to incorporate the rectification of simple customer faults.	Accept AER draft decision.
Control mechanisms	Accept the AER's F&A paper	Several amendments made to the formulae to give effect of the control mechanism.	Accept control mechanism draft decision. Propose amendments to side constraint formula
Incentive schemes	Apply all four available incentive schemes as per F&A paper. With respect to STPIS we proposed an alternate approach to calculate the Major Event Day thresholds	Accepted proposal.	Propose the newly amended STPIS is applied.
Pass-throughs	Apply same four nominated pass-through events as approved for the 2014-19 period with updated definitions	Accepted with minor amendments to definitions	Accept AER draft decision
Contingent Projects	Nominated the Western Sydney Aerotropolis as a contingent project.	Rejected. Consider a lower cost solution will be required during the 2019-24 period.	Accept draft decision.
Tariffs	Refer to proposal Attachment TSS0.01	Various amendments designed to quicken the transition to cost-reflective pricing.	Refer to Attachment 0.19

Alternative Control Services	Proposal	Draft Decision	Revised Proposal
Public Lighting	Existing arrangements plus the inclusion of a differential price for LED lighting.	Reduced prices by increasing LED standard life from 12 to 20 years and updated WACC and labour escalators.	Revised proposal reflects a 16 year standard life for LED lighting, otherwise accept AER draft decision.
Type 5 & 6 Metering	Existing arrangements with assumed impact of Power of Choice on customer numbers and the associated diseconomies of scale.	Reduced metering prices with a $4M reduction to opex and updated WACC and labour escalators.	Accept AER draft decision.
Ancillary Network Services	Existing arrangements carried forward and applied to new services.	Reduced several labour rates and time assumptions.	Accept AER draft decision.

How our revised proposal best serves the long term interests of customers

Our revised proposal continues to be based on customers' main goals of affordability, safety and reliability.

As a direct result of our engagement program our revised proposal will accept most aspects of the AER's draft decision and see our existing and future customers benefit from the following over the next five years:

An average residential customer will pay about **$66 less** annually for the network component of their bill in FY24 compared to today

An average small business customer will pay about **$113 less** annually for the network component of their bill in FY24 compared to today

99.9% average reliability will be maintained without compromising safety

105,000 connections will become available for new homes and businesses in 2019-24

*Prices in today's dollars

This is a positive outcome for the one million customers across the Endeavour Energy network and will ensure our customers will continue to pay the lowest network charges in NSW for the next five years.

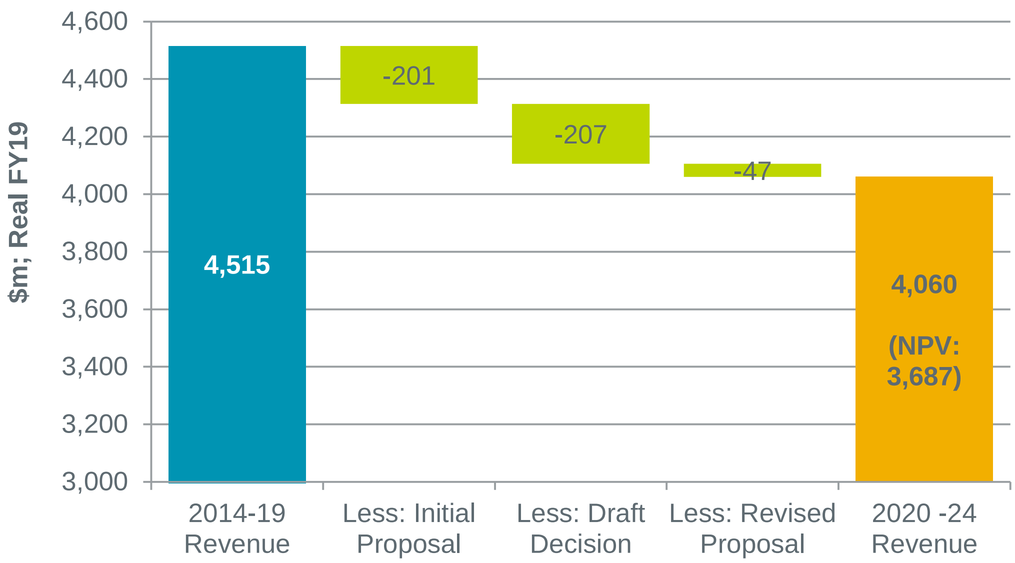
Our revised proposal delivers on customers' priorities in the following ways.

An affordable network

We have adopted the AER's final 2018 Rate of Return instrument. This, along with our updated capex forecast and other modelling updates results in a revised revenue allowance of $3.7 billion (nominal, NPV), 1.1 percent below the AER's draft decision.

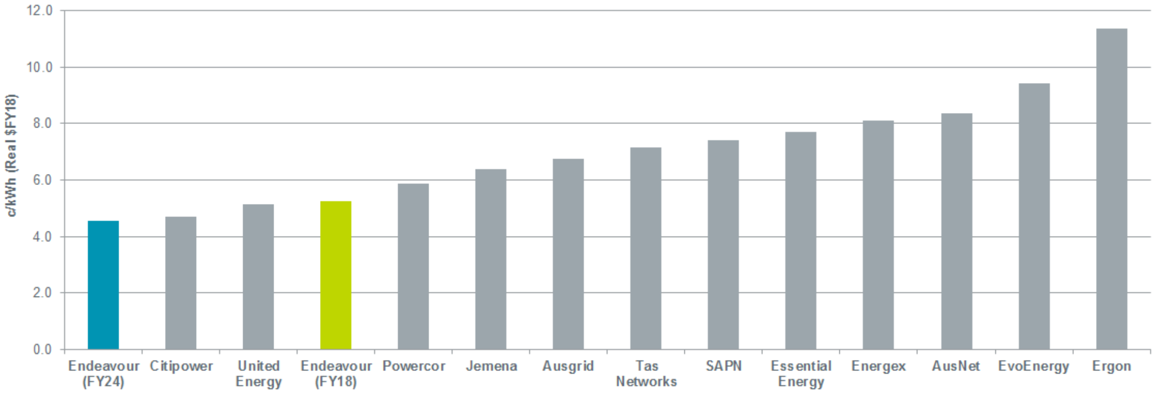
This is materially below our revenue allowance for the 2014-19 period as shown in the figure below.

Figure 1 - Endeavour Energy smoothed revenue 2014-19 compared to 2019-24 revised proposal



Importantly, this means we will continue to deliver some of the lowest network charges in the NEM.

Figure 2 - Endeavour Energy average network price (c/kWh) industry benchmark (FY17 RIN data)



An efficient network

We committed to achieving or bettering the AER's 2017-18 opex allowance in our initial proposal. We achieved this objective which is a reflection of concerted efforts to significantly reform our operations over the best part of a decade. Under our revised proposal, annual opex per customer improves from an average of $305 over 2014-19 to an average of $270 over 2019-24 (in today's dollars).

A safe, reliable and sustainable network

We have improved average reliability in 2017-18 and are committed to maintaining this performance over the 2019-24 period without compromising the safety of our customers, the public and our employees.

We have based our revised capex proposal on the capex revisions made in August 2018 which were confirmed in the AER draft decision.

We will continue to service record customer growth based on a revised sharing of new development costs. We have included additional capex for a lower cost solution to the Western Sydney Aerotropolis which was included as a contingent project in our initial proposal.

This revised capex forecast results in RAB per customer reducing from $6,326 at the end of 2018-19 to $6,053 in 2023-24 (in today's dollars).

A network of the future

We will transition customers to more cost-reflective tariffs, specifically a demand-based tariff. We have proposed a transition that preserves customer choice and that is mindful of the need to manage the impacts on customers.

We will continue to investigate innovative ways of addressing network constraints. We expect our new interactive network opportunity map will improve our engagement with the non-network market and help us achieve the capex reductions we have committed to.

We will also endeavour to provide customers with the opportunity to continue to connect and utilise generation technologies like solar PV and battery systems at increasing rates without compromising the safety and reliability of the remaining network.

To summarise, we are acutely aware that electricity prices and the rapid transformation of energy networks will remain important issues for many customers and stakeholders and we welcome your ongoing involvement in helping to shape the future of our business. We consider these outcomes demonstrate that we have responded to the key concerns raised by customers and stakeholders.

In the following section we provide more details about how we engaged with customers, what feedback we received and how we have responded to this feedback in preparing this revised proposal.

Customer Engagement

CHAPTER 1

1.1 Our new approach

Our objective is to develop a proposal that best serves the long-term interests of customers.

Our initial proposal and this revised proposal are the product of extensive engagement processes that have been a key factor in shaping our expenditure forecasts and organisational focus. In the following sections we provide a brief overview of; the engagement activities we have undertaken, the feedback we have received and how we have responded to this feedback in our revised proposal.

1.1.1 Engagement prior to lodgement of our proposal

Our goal over the past two years has been to substantially improve engagement and build on the extensive engagement we have undertaken since 2012.

We have spent more time consulting and listening and less time informing. We agreed on a principle of 'no surprises' and focused conversations on tough issues in our expenditure proposals, explaining risks and trade-offs and teasing out realistic alternatives where possible. This helped to build genuine respect and understanding, and narrow the gap where opinions differed. We also sought expert advice, broadened the involvement of our executive team and increased resources.

Finally, we tried some new engagement processes that had not been used by network businesses before. We responded to feedback from the AER's Consumer Challenge Panel and ran a series of 'deep dive workshops' which were co-designed to examine expenditure plans in greater detail with our regulator, shareholders, customer representatives, retailers, state and local government representatives, developer associations and Endeavour Energy's senior management team.

We have listened harder and adjusted our plans based on what we heard. Our executive team has played the lead role in engaging with both customers and stakeholders which has led to an increased sense of trust in the decision-making process.

We undertook four phases of engagement in the lead up to the submission of our initial proposal. These phases were explained in detail in our proposal and plain English overview. For the purposes of this document we have provided a high-level summary of these phases below. More detailed information about our most recent engagement follows.

Establishment phase
- Review and improvement
- Key learnings
- Strategy setting and design

Research phase
- City Smart persona research
- Research of attitudes towards electricity in Australia

Engagement phase 1
- Directions paper
- 11 Focus groups
- 2 Deliberative forums
- Online community
- Engagement audit

Engagement phase 2
- Extension granted to conduct further stakeholder engagement
- Deep Dive 1
- Deep Dive 2
- Deep Dive 3
- Deep Dive 4

1.1.2 What we heard and what we did

To provide the necessary background to this revised proposal, we have listed a summary of the most prominent themes of our engagement pre-lodgement of our regulatory proposal, and how we reflected these views in our initial proposal. More detailed information on these themes and our response is available in our initial proposal and the plain English overview which accompanied our submission.

Engagement findings and our response in our initial proposal lodged April 2018

What we heard	What we did in our initial proposal
Customers and stakeholders have asked us to concentrate on: • providing an affordable, safe and reliable electricity supply • containing investment to support new customer connections and economic growth • enabling customers' future energy choices • frank, respectful engagement with key stakeholders providing a clear understanding of risks and trade-offs.	• Made affordability, safety, and reliability our key deliverables for all customers. • Submitted plans that will build on a $75 reduction in network charges since 2012-13 and decrease by a further $25 for an average residential customer by 2024 in today's dollars. • Focused on maintaining reliability across the existing network and limit reliability improvements to the poorest performing areas, consistent with licence conditions. • Planned battery storage trials so that reliability is not compromised as we connect and utilise new generation and storage technologies in accordance with the *CSIRO/ENA Electricity Network Transformation Roadmap.* • Proposed an overall real reduction in public lighting charges in the order of 8 percent followed by annual CPI increases until end of period. • Proposed a pricing differential between LED and non-LED of 15 percent to reflect expected maintenance savings from increased density of LED lighting. • Reduced our proposed capital expenditure plans by almost $90 million (real, 2018-19). • Designed a new energy and demand-based tariff. • Continued to engage with stakeholders in a collaborative and respectful manner with the objective of working towards a regulatory outcome that is acceptable to all parties.

1.1.3 Since our initial proposal

We acknowledged that despite the success of our deep dive process, consensus had not been reached on two main issues at the time our initial proposal was submitted: our capital forecast and our capital contributions policy.

The AER and some stakeholder groups thought our capital forecast of $2.1 billion (real, 2018-19) should be reduced. The categories of focus were our augmentation expenditure, replacement expenditure and new connections expenditure.

Regarding capital contributions business groups, councils and developers prioritised timely and affordable construction of new networks to facilitate housing growth, while customer advocates wanted a fairer 'causer pays' capital contributions policy that does not burden existing customers.

As a result, we committed to undertake further engagement post-lodgement to resolve these issues.

1.1.4 Engagement phase 3: May to December 2018

We sought to engage further with the AER and stakeholders immediately following the lodgement of our initial proposal to resolve the outstanding matters outlined above. We did not believe it was in customers' interests, or stakeholders' interests to leave these matters unresolved for an extended period until the draft decision had been published.

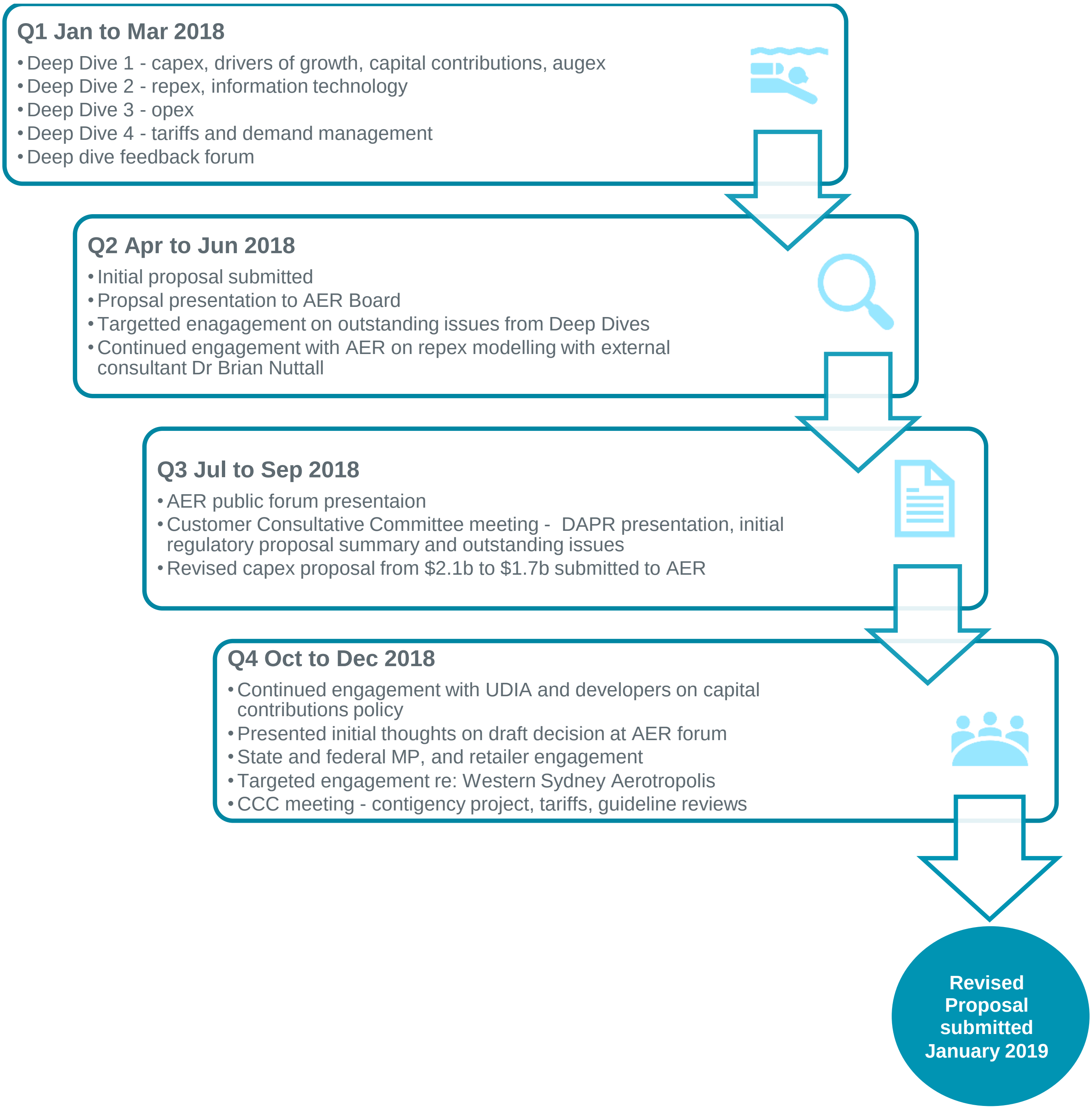
Instead, we favoured a more transparent and responsive approach that would reduce regulatory costs and provides greater certainty for customers.

We were also aware that stakeholder groups could be exposed to an intensive consultation period following the draft decision which was not optimal for them and would be a significant drain on their time and resource.

In addition to our capital forecast and capital contributions policy it also became clear that an opex productivity factor was a new issue to be considered. The AER committed to conducting a broader, industry wide review of its approach to forecasting opex productivity growth. For this reason, we focused our post-lodgement efforts on the outstanding matters from our deep dive engagement that were specific to Endeavour Energy.

As a result of this post-lodgement engagement and the separate opex productivity review, there were fewer issues arising from the AER's draft decision to be resolved. This allowed for more targeted engagement following the AER's draft decision on the TSS and the Western Sydney Aerotropolis contingent project. Below is a summary of the activities we undertook following lodgement of our initial proposal and the outcomes of this engagement.

Figure 3 - Endeavour Energy's customer and stakeholder engagement activities January 2018 to January 2019



1.1.5 Results of phase 3

What we heard	What we have done
Pricing outcomes for customers	
• Stakeholders felt that Endeavour Energy was working hard to become more efficient which will lower their operating costs and provide greater benefit to consumers • They wanted us to do more to reduce network costs for customers.	• Submitted plans that will see Endeavour Energy customers continue to have the lowest network charges in NSW. • Submitted revised plans that mean the average residential and small business customer will annually pay approximately $66 and $113 less in FY24 than they do today (in today's dollars). • Submitted plans that will see annual opex per customer improve from an average of $305 in 2014-19 to an average of $270 in 2019-24.
Capital expenditure program	

• Most stakeholders raised concerns with the overall level of capital investment proposed by Endeavour Energy.
• Areas of concern related primarily to:
  ○ replacement program; and
  ○ concerns that non-network options such as demand management were not adequately considered as cost-effective alternatives to augmentation investment
	• Acknowledged the amount of capex proposed was an outstanding issue from our deep dive process, and we committed to further engagement.
	• On 30 August 2018 we submitted a revised capex forecast of $1.70 billion (real, 2018-19), a 21 percent reduction from our proposal forecast of $2.16 billion (real, 2018-19). We have committed to this lower amount without compromising our current network performance and reliability levels.
	• Overall, these changes resulted in an improvement in the pricing outcome associated with our proposal. The AER accepted these revisions in the draft decision.

Contribution arrangements for connecting new customers and development areas	
• Most stakeholders who commented on this issue raised concerns with the amendments to the funding arrangements for connecting large developments that we adopted in 2017. • More clarity on the policy question of how to apply cost reflectivity, with specific focus on defining the beneficiaries of the investment.	• Acknowledged this was an outstanding issue from our deep dive process, and we committed to further engagement. • Committed to changing our capital contribution policy resulting in a 62 percent reduction to our connection capex forecast and a 36 percent increase in our capital contribution forecast. The policy is now more 'causer pays' to reflect a view strongly advocated by several stakeholder groups. Existing customers will go from paying for 36 percent of connection costs to 15 percent.
Forecast operating cost efficiency improvements	

• Customer advocate groups raised the issue of requiring productivity improvements to be built into the forecast opex allowance at the AER's public forum and subsequently in their submissions. The issue was also noted in submissions from retailers.
• This issue was not one that was raised during our pre-lodgement engagement, where Endeavour Energy had proposed to apply the AER's base/step/trend method from a base year
	• Unlike the issues outstanding at the end of the deep dive process, Endeavour Energy is not proposing to amend its proposal, which is materially lower than our 2014-19 opex spend, in light of these submissions.
	• Rather the proposal lodged rests on[5]:
	  ○ Our 2017-18 opex performance in meeting the AER's efficiency benchmark level
	  ○ relying on the incentive-based framework to

[5] With respect to the AER's draft forecasting opex productivity decision our response is contained in Attachment 0.15

What we heard	What we have done
opex considered to be efficient. • Opex and the Rate of Return are important factors. Draft 1 percent productivity factor seen as the bare minimum but would like to see a higher productivity factor.	drive and fund efficiency improvements that customers have, and will continue to, receive the majority of the benefit of. ○ absorbing cost pressures arising from the reduced capital program, such as required DM opex and increased maintenance as discussed earlier. ○ accepting the AER's reduced labour cost escalators. ○ absorbing the costs of all potential step changes that may occur over the period estimated to be $10m p.a.
Tariff reform and approach	
• Customers and customer advocates were generally supportive of the approach proposed by Endeavour Energy, although improvement opportunities were identified in some submissions, often in the area of more locational targeted and innovative tariff types. • Retailers were less supportive, requesting a slowing down of cost reflective pricing, questioning the need in the current environment, and requesting greater uniformity across the state. • The AER recognised our focus and leadership on customer impact tariff reform, but sought more aggressive transition to cost-reflective pricing than proposed by Endeavour Energy.	• Our initial TSS proposal was prepared in accordance with best practice principles for customer engagement and in close consultation with consumers, their representatives and retailers. This was acknowledged by both stakeholders in submissions and the AER in its draft TSS decision. • Accordingly, we have been guided by stakeholder feedback responding to the AER's draft decision. On this basis we have accepted all aspects of the AER's draft decision with the exception of the tariff assignment policies. • We have retained our proposed tariff assignment policies as we are concerned that the draft decision de-emphasises the consumer impact principle and puts at risk valuable tariff and metering reforms.
Contingent project – Western Sydney Airport	
• The AER rejected the Western Sydney Airport (Aerotropolis) project as a contingent project on the basis that some investment will most likely be required and a lower cost alternative may be available through staging the solution. • The AER wanted Endeavour Energy to undertake more consultation and assessment and requested we explore whether the project could be rolled out in increments over successive regulatory periods.	• Accepted the AER's view that the Aerotropolis project was not 'uncertain' and some form of investment in the five year period will be required. • Presented several investment scenarios to key stakeholders including Western Sydney Airport and selected a preferred option following their input. • Revised capex forecast to incorporate a lower cost solution compared to our original proposal. The contingent project of $61.2m (real, 2018-19) was designed as a one-off solution. We have instead proposed an initial project of $39.3m (real, 2018-19) that involves a lower cost solution that utilises existing network in the earlier stage of development with further work to be considered for the next regulatory period.
Engagement	
• Stakeholders widely commended TSS engagement. Endeavour Energy is seen as a business that stood out in terms of being progressive on the user pays path. • Positive feedback on targeted engagement that was undertaken following stakeholder 'pushback' on proposed capital contributions policy and capex proposal.	• Conducted targeted engagement in the lead up to this revised submission as we were acutely aware of intensive engagement being undertaken by other NSW networks.

Our Revised Proposal

CHAPTER 2

2.1 Overview

In accepting most aspects of the AER's draft decision, our revised proposal continues to put downward pressure on electricity bills for our customers while also addressing stakeholder and customer priorities.

In April 2018 we submitted our plans for the 2019-24 period to the AER. These plans would have reduced network charges by one percent each year in today's dollars, locking in 10 years of no real price increases in network charges.

This reflected in part substantial improvements to our operating efficiency over the past few years and represented a significant positive step for the one million customers within our network that already pay the lowest network charges in NSW and will continue to do so for the next five years.

Since lodging our initial proposal in April, we have continued to engage with the AER and stakeholders with the objective of working towards an outcome that is acceptable to all parties. Based on these discussions, in August last year we reduced our capital plan from $2.1 billion to $1.7 billion and increased our capital contribution forecast. These changes reflected the clear feedback we received that new developments should fund a higher proportion of their connection costs and that elements of our proposed repex and augex needed to be reduced and/or deferred.

The AER in its draft decision accepted most aspects of our initial proposal and our subsequent reduction in proposed capital expenditure, including the drivers of future revenue requirements. The AER also adopted a new, lower draft Rate of Return guideline which was the primary driver behind a 4.1 percent reduction in the revenue we can collect and thereby further reducing costs for our customers. This was not available at the time of our April submission and we have reflected the now final Rate of Return instrument in full in this revised proposal.

Although smaller in quantum, other differences between our initial proposal and the AER's draft decision have been informed by the input of peak consumer groups and electricity retailers. Based on these discussions, our revised proposal:

1. accepts most components of the AER's draft decision and updates several aspects where more up to date information is available.
2. accepts most components of the draft decision with respect to our TSS with the exception of the tariff assignment policies. Based on feedback from peak stakeholder groups we have retained our proposed tariff assignment policies as we consider the AER's approach de-emphasises the consumer impact principle and puts at risk valuable tariff and metering reforms.
3. includes proposed lower-cost capital expenditure for the Western Sydney Aerotropolis, in line with the AER's view that some form of investment would be required during 2019-24 but that lower cost solutions should be considered in place of the original contingent project approach. The revised project will better utilise the existing surrounding network in the earlier stages of development.

The building block components of our revised proposed indicative annual revenue requirements for 2019-20 to 2023-24 are 1 percent lower than the AER's draft decision and outlined in table 1 below:

Table 1 - Forecast standard control revised revenue requirement over the FY20-FY24 regulatory control period

$m; Nominal	2019-20	2020-21	2021-22	2022-23	2023-24	Total (NPV)
Return on capital	390.5	398.3	403.5	408.2	413.5	**1,702.3**
Return of capital	106.3	120.0	130.6	138.8	134.1	**529.6**
Operating expenditure	287.6	300.2	315.3	331.2	347.5	**1,332.0**
Cost of corporate tax	29.0	28.2	32.8	35.3	34.5	**134.5**
Revenue adjustments	(223.9)	74.5	86.7	72.7	2.5	**(11.8)**
Total unsmoothed revenue	589.5	921.3	968.9	986.2	932.1	**3,686.6**
Smoothed ARR	855.9	857.4	861.7	882.6	904.0	**3,686.6**

2.2 Our initial proposal

Our initial proposal, for the period from 1 July 2019 to 30 June 2024, was lodged 30 April 2018 and was developed following a change in our ownership structure and an extensive customer and stakeholder engagement program.

A change in ownership during 2017 means Endeavour Energy is now 50.4 percent owned by an Australian-led consortium of long-term investors in the private sector operating the network under a 99-year lease. This enables Endeavour Energy to leverage the vast infrastructure management experience of the consortium to transform our business into a world-class utility. The consortium has identified five priorities that will shape the future direction of the business:

- Improving safety for staff and the community.
- Developing a stronger, flexible and better skilled workforce.
- Investing to improve network resilience and customer outcomes.
- Over time, reducing customers' bills.
- Supporting future growth in Western Sydney and across our network.

Similar priorities were identified by customers and stakeholders during our engagement program. Based on these priorities we committed to improving our performance in 2018-19 and passing the benefits through to our customers over the 2019-24 period. Our most recent performance against these key priorities is summarised below.

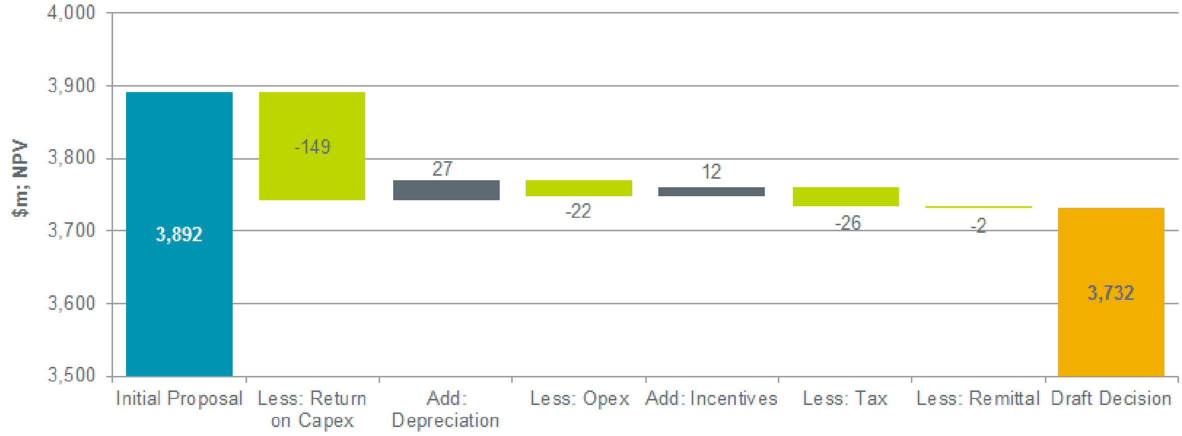
- Affordability: Over the five-year period between 2012-13 and 2017-18, Endeavour Energy's average annual network charges decreased by $75 in nominal terms (for an average residential customer) while our share of the average residential bill has reduced to 31 percent (from 43 percent in 2016-17). Our proposed revenue requirement would see annual network charges decrease by a further $10 in nominal terms for the average residential customers over the 2019-24 period.
- Efficiency: We have continued to respond to incentives through improving our operating efficiency. We committed to achieving the AER's efficient opex allowance during the 2014-19 period. We have reduced our opex by $72.9 million (real, 2018-19) since 2014-15, achieving the AER's 2017-18 opex target. In accordance with the EBSS we used this outcome as our base for forecasting our 2019-24 opex requirements which means customers will receive the majority of the benefits.
- Reliability: Over the 2014-19 period we improved our reliability performance while achieving the AER's opex target and spending less than the capex allowance. This means our customers are receiving a better service at a lower cost. Our 2019-24 STPIS targets will reflect our 2014-19 performance at a lower price.
- Servicing growth: We have continued to service the significant customer growth and development occurring in our network area. We recently connected our one millionth customer and we expect the population of Western Sydney to swell by a further 900,000 over the next 20 years with the introduction of Sydney's second airport and the continued development of the North West and South West Priority Growth Areas. We adjusted our capital contribution policies in response to stakeholder feedback to ensure we continue to service growth in a timely, fair and efficient manner.
- Safety and Compliance: Our performance has continued its improvement against key safety metrics; total recordable injuries, lost time injuries and frequency rates. Our expenditure forecasts were developed with the objective of continuing to operate and maintain our network in accordance with various International and Australian Standards, including vegetation management clearance requirements, our licence conditions and numerous other obligations as a DNSP.

Our revised proposal is based on this improved performance containing an efficient estimate of the revenue required to continue to deliver an affordable, safe and reliable electricity supply that services growth efficiently and enables customers' future energy choices.

2.3 AER draft decision: detailed response

The AER's draft decision did not accept our proposed unsmoothed distribution revenue requirements of $3.89 billion (nominal, NPV)) for the 2019-24 period, and instead set an alternative allowance of $3.73 billion (nominal, NPV) comprising the adjustments set out in the figure below.

Figure 4 - Building Block Revenue (nominal, NPV) initial proposal compared to AER draft decision



A summary of the differences in each building block component between our proposal and the AER's draft decision is provided below, along with our revised position.

2.3.1 Return on capital

In our initial proposal we applied the then prevailing rate of return guideline i.e. the 2013 version. The AER instead adopted the draft 2018 rate of return guideline in the draft decision. In this revised proposal we have adopted the final 2018 rate of return instrument which drives the reduction to the 'return on' capital allowance pictured above.

The return on capital allowance is also lower following the reductions we made to our capex forecast discussed in section 2.3.3 below.

These reductions were marginally offset by increases associated with higher than forecast capital spend in 2017-18 and the AER's inflation forecast which is 2.42 percent compared to our proposal of 2.50 percent.

We maintain our position that the prevailing rate of return guideline or instrument should be applied in determinations. The final rate of return instrument has now been published resulting in an average WACC estimate of 5.74[6] percent compared to the AER's draft decision of 5.71 percent. This difference is driven by an increase to the market risk premium from 6.0 percent to 6.1 percent.

In adopting this instrument, we repeat the concerns raised during the consultation process by the ENA, investors and other networks. We consider the rate of return is below international comparisons and it poses a significant risk to our ability to raise the capital required to manage the network in a safe and reliable manner over the longer term. We recently commissioned a report (Attachment 0.06) by Deloitte Access Economics (Deloitte or DAE) which outlines the benefits associated with the 'future grid' and the investment environment required to unlock its full potential. As noted by the ENA, the final rate of return instrument fails to provide the balance required to realise the benefits of grid modernisation.

[6] We note the AER will need to update the cost of debt and risk-free rate, in accordance with the agreed averaging periods in its final decision.

2.3.2 Regulatory depreciation

The AER accepted our proposed approach to regulatory depreciation. The allowance in the draft decision differs from our initial proposal due to adjustments made to our capex forecast and the lower expected inflation rate.

We accept the AER's draft decision methodology and have updated it to incorporate the impacts of the changes to the opening RAB and the capex revisions. We note that it will be further updated to reflect the most recent inflation data at the time of the AER's final decision.

Following the AER's adoption of the diminishing value method for tax depreciation we suggest the AER review whether a straight-line method remains appropriate for regulatory depreciation purposes. The depreciation methods have been aligned to date and our submission to the Tax Review identified inter-generational and long-term pricing benefits from applying the diminishing value method to both regulatory and tax depreciation.

2.3.3 Capital expenditure (Capex)

The AER has accepted our revised capex forecast of $1.7 billion (real, 2018-19) which was lodged in August 2018, given the difference between it and the AER's alternative estimate was immaterial.

We accept this decision and note the constructive engagement we have had with the AER and stakeholders to reach this outcome since the initial proposal in April 2018.

Our initial capex forecast of $2.1 billion (real, 2018-19) was developed using a combination of top-down and bottom-up models including the AER's repex model and was driven by the need to replace ageing assets and to service significant customer growth in several locations across our network.

As a result of further engagement with the AER and stakeholders, a number of concerns were identified and addressed. These included:

- Governance and risk framework: the AER and its consultant EMCa considered our governance and risk framework to be conservative and prioritisation process to be unsophisticated;
- Forecast methodology: the AER and EMCa considered our forecasting methodology did not capture the expected benefits of our newly implemented delivery model, potential non-network/demand management opportunities and the historical benefits we realised from deferment/staging investment;
- Reimbursement policy: stakeholders were concerned with our capital contribution policy and did not consider it constituted an efficient or fair sharing of costs between existing and connecting customers;
- Detailed justification: the AER, EMCa and stakeholders raised concerns with our business case level documentation and whether sufficient cost-benefit analysis had been conducted; and
- Overheads: stakeholders were concerned that our capitalised overheads did not reflect the benefits that should be expected of our Information and Communications Technology (ICT) capex program.

We came to the view that some of the concerns raised about our capex forecast were reasonable and that a reduced forecast would better serve the interests of customers. We submitted a revised capex forecast of $1.7 billion (real; 2018-19), a 21 percent reduction to the original proposal, to the AER on 30 August 2018.

The modifications made to better reflect consumer preferences, included:

- Reducing the connection capex forecast by almost $200 million with these connection costs to be paid by developers and new residents instead of being spread over the total customer base;
- Reducing replacement expenditure by 25 percent based on new repex modelling which benchmarks asset lives and unit costs across the industry rather than against a DNSP's historical performance; and

- Deferring various augmentation works through temporary supply options, utilisation of existing network infrastructure and non-network options.

As noted in our August 2018 submission revising our capex forecast, these reductions are material and increase risk of asset failure or delaying growth in our network area. Capex reductions will put upward pressure on our opex spend given the increased maintenance and non-network costs that will be required to achieve these outcomes. However, we have committed to achieving these reductions without compromising the service and reliability outcomes promised in our initial proposal.

We are currently replacing our ICT systems which will improve the information we have about our network and improving our asset management practices in response to the feedback we have received from the AER and EMCa. These improvements should enable us to deliver the outcomes we have committed to at a lower cost and without increasing risk.

We note that some stakeholders have requested additional information on the revised capex forecast of $1.7 billion (real, 2018-19) and how it was developed. The AER's draft decision provides a detailed explanation of the AER's assessment approach and alternative capex estimate. We consider the draft decision provides comfort that our revised capex forecast is a reasonable and efficient estimate informed by expert advice, robust modelling and detailed analysis.

Addressing outstanding stakeholder capex issues

We note that the Consumer Challenge Panel 10 (CCP10) and other stakeholders have raised concerns with capitalised overheads and ICT capex. These concerns are industry wide and centre on how ICT capex is assessed and the need to more clearly define the benefits that should be expected of it, for instance a reduction in capitalised overheads. We address this feedback as follows:

- We provided evidence in our initial proposal that **our forecast capitalised overheads** are efficient. To summarise, our proposal showed that:
    - Our total overheads have reduced significantly from an annual average cost of $307 (real, 2018-19) per customer (FY09-13) to $258 (real, 2018-19) per customer (FY14-17)
    - Our average capitalised overheads per customer (FY12-16) was amongst the lowest in the NEM;
    - Our capitalisation rate (FY09-16) was lower than most DNSPs despite capex making up a relatively higher portion of totex; and
    - The AER has historically estimated 25 percent of capitalised overheads to be variable. Our forecast capitalised overheads increased by 10 percent despite a larger increase in system capex.

We acknowledge that in revising our capex forecast we did not adjust our capitalised overheads forecast as our focus was on setting an overall level of capex that was considered efficient in a relatively short period of time in order to respond to AER and customer feedback in a timely manner. The category level breakdown of the revisions is therefore indicative to give effect to the reduction and will necessarily vary to reflect circumstances as they arise. We consider the 21 percent overall reduction to our capex forecast addresses the concerns listed above, including overheads.

As noted by the AER in its draft decision, we are provided with an efficient revenue allowance for the period. Reducing our forecast capex requirements by 21 percent compared to what we considered was an efficient forecast will be a challenge which could result in increased opex and/or reduced service outcomes if managed poorly. However, we have strong incentives to achieve or end up below the capex allowance where it is efficient to do so without compromising service outcomes.

- Our initial proposal provided substantial evidence supporting the necessity and efficiency of our **ICT capex forecast** was well justified and accepted in the AER's draft decision.
    - A material portion of our ICT capex is required in order to comply with our critical infrastructure licence conditions, and our forecast ICT capex was below both 2009-14 and 2014-19 levels providing prima facie evidence of its efficiency under a revealed cost incentive based regulatory framework.

- Our forecast ICT capex as a percentage of total capex is 4.2 percent compared to the 2016 industry average of 7.2 percent, our ICT totex per employee has been consistently below the industry average, and our ICT totex per customer in 2016 was equal to the industry average.

At a high level, our ICT investment will enable us to deliver the reductions made to our capex proposal both prior to lodgement (e.g. $50 million repex reduction) and post lodgement (the further 21 percent reduction) through improved data and processes that will enable more efficient management of our assets.

With respect to opex we did not propose any step changes associated with our ICT transformation program. It is typical for ICT transformation to be followed by a period or short-term opex increases associated with training staff and as new processes and systems are 'bedded down'. Instead, we sought to absorb approximately $10m p.a. of step changes, the equivalent of a one percent p.a. productivity factor, through yet to be determined efficiency savings.

In light of the above, we have not revised the draft decision capex forecast for these matters which we consider to be more applicable at an industry level rather than to our current circumstances.

2.3.4 Western Sydney Aerotropolis

We have revised our capex forecast to incorporate the Western Sydney Aerotropolis which was originally included as a contingent project in our initial proposal. This growth area will include Sydney's second airport and become Sydney's 'third city', key details are as follows:

- Land size: 11,200 hectares which is comparable in size to the area extending from the Sydney CBD to the Kingsford Smith Airport and the Eastern Suburbs.
- Load requirements: 26 MVA by 2024 growing to 176 MVA by 2035 and 850 MVA at maturity post-2050.
- Airport details: a full-service airport catering for both domestic and international passengers as well as freight services. Construction is underway and the Australian Government has committed up to $5.3 billion to develop the Airport. The airport is on track to open in 2026 with a second runway to be added at a later date.
- Infrastructure: the Australian and NSW governments are constructing new and upgraded roads around the airport under the $3.6 billion Western Sydney Infrastructure plan. The governments have also committed a further $7.0 billion to a new North South Rail line and South West Rail link.
- Industrial and agricultural precincts will support approximately 200,000 jobs across Western Sydney including the re-location of Sydney Markets, a combined university campus from four major metropolitan universities, advanced manufacturing and aerospace industries.
- Residential precincts will house approximately 60,000 dwellings

Supplying this growth area will be critical to supporting economic development and investment in Western Sydney. We have been in constant dialogue with the Western Sydney Airport Corporation (WSA Co), councils, Government and stakeholders to understand their expectations and requirements over the last few years.

At the time of our initial proposal the full extent and nature of the supply requirements were still subject to a degree of uncertainty. Based on the preliminary forecasts we developed a contingent project to service the expected long-term requirements of the growth area at the lowest overall cost.

The AER and stakeholders raised concerns with this approach and considered that a lower cost solution may be adequate in servicing growth in the early stages of development. On this basis, the proposed contingent project was not accepted.

Since our initial proposal we have received additional information on the growth area. Both the nature and the timing of the development are now more certain. We have developed a lower cost solution that will service expected growth in the shorter term by building a single 132kV feeder (rather than two) and utilising the existing surrounding 33kV network. This option will cost $39.3 million (real, 2018-

19) and provide additional time to monitor actual growth and investigate non-network solutions for servicing expected long-term growth. This is discussed in more detail in Attachment 0.11 to this revised proposal.

2.3.5 Operating expenditure (Opex)

Our opex forecast was developed using the AER's preferred base-step-trend method in accordance with the revealed cost framework. The 2019-24 forecast was based on our expected 2017-18 performance.

In its draft decision the AER has accepted the efficiency of our base year opex based on its benchmarking analysis. The primary difference between the forecast opex in our initial proposal and the AER's draft decision estimate is a reduction in the forecast labour price growth.

In our initial proposal, labour price growth was accounted for using a forecast in the NSW utilities wage price index provided by BIS Oxford Economics. Output growth was calculated based on forecast growth in customer numbers, ratcheted maximum demand and circuit line length weighted in accordance with previous AER decisions. We did not apply any step changes or productivity factors. The AER in its draft decision applied its standard approach of averaging forecast growth in the NSW utilities wage price index from Deloitte and BIS Oxford Economics.

The AER also adjusted the benchmark proportion of labour opex from 64.8 percent to 59.7 percent[7], and refined the output growth factor weightings by relying on the specification and estimated weights for four models rather than a single model as in previous decisions.

We accept the AER's draft decision methodology. We have updated it to incorporate our actual 2017-18 opex and the output weightings from the final 2018 ABR, including a new econometric model which Economic Insights consider to be reliable[8]. Our revised opex forecast (including debt raising costs) is $1,469.6 million (real, 2018-19), a $1.0 million increase to the AER's draft decision.

In the draft decision, the AER noted that it is currently reviewing its approach to forecasting opex productivity. Consistent with previous AER decisions, we consider the available evidence does not support a positive productivity factor (to the contrary, the evidence favours a negative one). We have other concerns with the AER's recent draft forecasting opex productivity decision (including in relation to procedural fairness) and consider it contains errors. For further details, refer to our response to the AER's draft decision on forecasting opex productivity, Attachment 0.15 to this proposal.

We also note that at the time of our initial proposal we identified step changes totalling up to $10 million p.a. Since the lodgement of our initial proposal we have experienced further cost pressures, specifically our insurance premiums have increased following the 2017 Californian bushfires and these are expected to further increase with the 2018 Californian bushfires and the withdrawal of some insurers from providing bushfire coverage. On the basis of the AER's draft decision and our revised opex proposal we have not sought to pass on these step changes and have maintained our position of absorbing them within our opex allowance.

2.3.6 Revenue adjustments

The revenue adjustments in our proposal included our forecast carryover EBSS incentive payments for the 2014-19 period, a forecast DMIA allowance and the 2014-19 remittal decision. Our forecast CESS payment was zero but we had concerns with the accuracy of the model that we raised in consultation with the AER.

In its draft decision the AER has:

- updated the forecast EBSS carryover benefit for inflation;

[7] Our proposal relied on the draft 2017 ABR and not the 2013 ABR as stated in the AER's draft decision. The draft 2017 ABR relied on unadjusted data from DNSPs on their labour opex. The final 2017 ABR adjusted this data for DNSPs that reported contracted opex which consisted zero labour opex using the contracted opex labour/non-labour split of other DNSPs.
[8] Economic Insights, Economic Benchmarking Results for the AER's 2018 DNSP Annual Benchmarking Report, November 2018, p. 19

- included a $12.3m (real, 2018-19) forecast CESS carryover benefit following revisions it has made to the CESS model;
- updated the forecast DMIA allowance to reflect the draft decision revenue allowance; and
- updated the 2014-19 remittal amount for the AER's latest actual and forecast information.

We accept the AER's draft decision methodology and we have updated it to reflect our actual capex and opex performance in 2017-18. The reduces the CESS benefit from $12.3m (real, 2018-19) to $7.0m (real, 2018-19) and marginally reduces the EBSS benefit. As a consequence of other amendments, we have also updated the DMIA allowance from $4.3m (real, 2018-19) to $4.1m (real, 2018-19).

2.3.7 Impact of set aside 2014-19 determination and remittal

As noted in our initial proposal, a determination was not in place for the majority of the 2014-19 period due to the appeals process. In the absence of a regulatory determination, Endeavour Energy gave, and the AER accepted, an Enforceable Undertaking for 2016-17 to 2018-19, under section 59A of the NEL.

At the time of submitting our initial 2019-24 proposal, we were in the process of consulting with the AER on the 2014-19 re-determination and pricing undertaking for 2018-19. Our initial proposal was based on our proposed 2014-19 re-made revenue allowance and our forecast revenue recovery for the 2014-19 period. The assumptions were:

- During the 2014-19 period we expected to recover an additional $336.7 million (real, 2018-19) in DUOS revenue compared to the AER's April 2015 2014-19 determination.
- We proposed to retain $110.0 million (real, 2018-19) of the over-recovery and return $226.7 million (real, 2018-19) to customers during the 2019-24 period in order to resolve the outstanding matters of dispute from our 2014-19 remittal.

The AER made its final re-made 2014-19 decision on 20 September 2018 which accepted our proposal for this period. We have updated this revised proposal to reflect our actual revenue over-recovery for 2017-18 and our updated forecast over-recovery for 2018-19. This results in a remittal amount of $243.5 million (real, 2018-19) compared to the AER draft decision amount of $228.3 million (real, 2018-19) which further benefits customers.

2.3.8 Corporate income tax

The corporate income tax allowance in our proposal was based on a 0.4 gamma as per the AER's application of the prevailing (at the time) 2013 Rate of Return guideline. In its draft decision the AER adopted a gamma value of 0.5 as per the 2018 draft rate of return guideline. This is the primary driver for the reduced corporate income tax allowance. This allowance was also impacted by other aspects of the AER's draft decision; its estimate of inflation, the capex forecast and the return on and of capex.

The final 2018 rate of return instrument includes a gamma estimate of 0.585. We have applied this estimate in our revised proposal. We have also updated the corporate income tax allowance as a consequence to changes to the other building block components.

2.3.9 Other constituent decisions

In addition to the revenue building blocks, there are several other key decisions the AER is required to make as part of a distribution determination. This includes a decision on our TSS, which is discussed separately in Attachment 0.19 to this proposal. The majority of the remaining constituent decisions, relating to the services we provide, how these services are regulated, and which incentive schemes are to apply and how, are addressed by the AER's F&A decision.

In our initial proposal we adopted all aspects of the AER's F&A paper. In addition to these F&A matters we also nominated four pass-through events, a contingent project for the Western Sydney Aerotropolis and a connection policy.

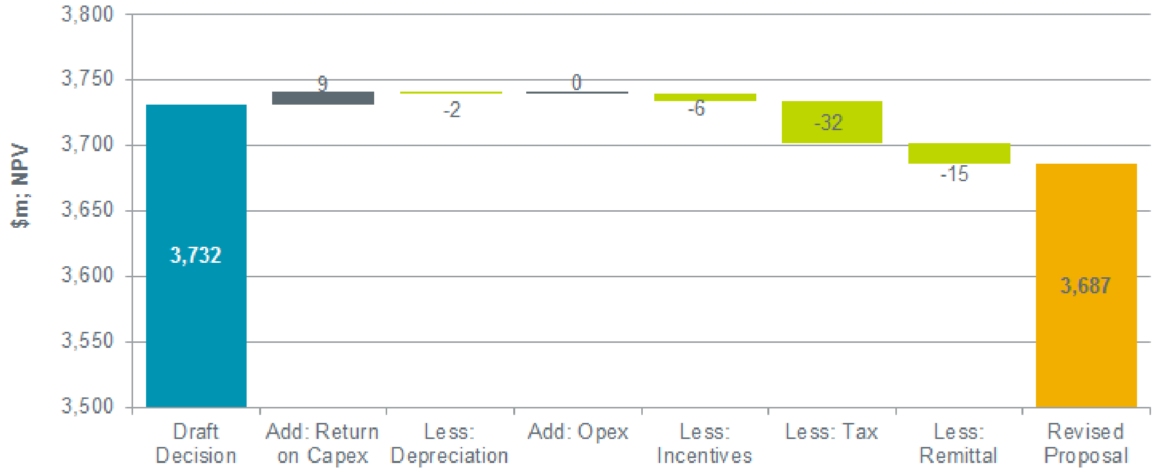
In the draft decision the AER has:

- expanded the ‘common distribution services’ definition to include the rectification of simple customer faults in particular circumstances. This is to ensure that the ring-fencing guideline does not result in undesirable service outcomes for customers. We support this amendment and accept the AER’s draft decision.
- accepted our proposed negotiating framework for negotiated distribution services. We accept the AER’s draft decision.
- accepted the proposed form of control for standard and alternative control services, being a revenue cap and price cap respectively. We accept the AER’s draft decision.
- provided a more detailed decision on the formulae to give effect to the control mechanisms. We have some concerns with the AER’s draft decision and propose several amendments to the AER’s draft decision. See section 2.4.4 for further details.
- accepted our proposal that all four available incentive schemes apply to Endeavour Energy for the 2019-24 period. We note the AER released an updated STPIS and Distribution Reliability Measures Guideline (DRMG) 16 November 2018. We propose that the updated STPIS and DRMG should apply to Endeavour Energy for the 2019-24 period, see section 2.6 for further details.
- accepted the four nominated pass-through events with minor amendments to the definitions to align them with more recent decisions. We accept the AER’s draft decision.
- amended our proposed connection policy to more clearly address three Rules requirements. Some of these changes were proposed by Endeavour Energy in consultation with the AER post-lodgement of our initial proposal. We have made a few minor amendments to the AER’s draft decision for its consideration; see Attachment 0.05. to our revised proposal for an amended connection policy.
- rejected the proposed contingent project on the grounds that a lower cost solution will most likely be required during the 2019-24 period. We have considered feedback from the AER and stakeholders and have removed the contingent project and have updated our capex forecast to incorporate a lower cost solution.

2.4 Revised Revenue Requirements

Our revised proposed smoothed revenue requirement of $3.7 billion (NPV) is a one percent decrease compared to the AER's draft decision. The decrease is attributable to various updates and revisions which impact each building block as evident in the figure below.

Figure 5 – Revised revenue requirement (nominal, NPV) compared to the AER Draft Decision



2.4.1 Modelling updates

We have accepted most aspects of the AER's draft decision. In this revised proposal we have updated the AER's draft decision for our revised capex forecast and to account for information that was not available to the AER at the time it was making the draft decision. The updates we have made to the AER's draft decision, and the impacts of these changes are summarised in table 2 below.

Table 2 – Revenue impacts of the adjustments made to the AER's draft decision

Input	Description	Revenue impact ($m; nominal)
Actual 2017-18 revenue	We have updated our 2014-19 remittal revenue adjustment to reflect our 2017-18 actual revenue over-recovery.	-14.7
Actual 2017-18 capex	We have updated the RFM and CESS to reflect our actual 2017-18 capex performance.	-2.7
Actual 2017-18 opex	We have updated the EBSS and Opex model to reflect our actual 2017-18 opex performance.	0.3
Output growth	We have updated the Opex model to reflect the output weightings from the AER's final 2018 ABR.	-0.4
Forecast Capex update	We have updated our capex forecast to correct an error in the treatment of disposals in the AER's draft decision and to incorporate the Western Sydney Aerotropolis project.	-1.0
Final rate of return instrument update	We have updated our forecast revenue requirements based on the final 2018 rate of return instrument.	-26.6
DMIA	We have updated the DMIA as it is calculated in reference to forecast annual revenue .requirement which has been revised.	-0.2
Total adjustments		**-45.3**

As evident in the table, the revenue impact of these changes is relatively low, and we consider these to be uncontroversial amendments to the AER's draft decision.

We also acknowledge that additional updates will be required in the AER's final decision that will result in further refinement of the forecast revenue allowance.

We also note that an update will be required for the 2019-24 STPIS performance targets specified in the AER's draft decision. In the draft decision the AER proposed reliability and customer service targets for STPIS purposes on the 2013-14 to 2016-17 years.

The AER noted that these targets would be updated to reflect actual performance in 2017-18 which was unavailable at the time of making the draft decision. We support this and propose that the 2019-24 performance targets are adjusted to incorporate the 2017-18 results in accordance with clause 3.2.1(a)(1B) of version 2.0 of the STPIS.

2.4.1 Smoothed revenue requirements and x-factors

We have set out our acceptance and proposed amendments to each of the draft decision building blocks above. By adding these building blocks together, we derive our revised proposed total unsmoothed annual revenue requirement (ARR) for the 2019-24 regulatory period. This revenue will be recovered from our customers via network tariffs (or charges).

To smooth the lumpy profile of these revenue requirements and limit customer price volatility between years, the Rules allow the AER to constrain revenues to follow a CPI-X path. The AER specified what we considered to be a sustainable CPI-X path in its draft decision based on the draft ARR. Below we outline our revised proposed X-factors to deliver similarly sustainable pricing outcomes over the 2019-24 period.

Proposed smoothed revenue and X-factors

Our customer engagement has consistently confirmed stakeholder preference for stable, smooth price movements between years.

Similar to our initial proposal and the AER draft decision, we have derived X-factors that comply with the Rules and are consistent with principles ensuring that the:

- net present value of smoothed and unsmoothed revenue over the 2019-24 period are equal;
- pricing impact is smooth and consistent over the period; and
- difference between smoothed and unsmoothed revenue in 2023-24 is as low as reasonably possible in order to minimise pricing volatility between regulatory periods[9].

The resulting revenue X-factors are provided in the PTRM, Attachment 0.03. The revenue requirement and pricing X-factors that underpin them are provided in table 3 below.

Table 3 - Proposed unsmoothed and smoothed annual revenue requirement for FY20-FY24

$m; Nominal	2019-20	2020-21	2021-22	2022-23	2023-24	Total (NPV)
Unsmoothed revenue requirement	589.5	921.3	968.9	986.2	932.1	**3,686.6**
Revenue X-Factors*	1.90%	2.20%	1.88%	0.00%	0.00%	
Real price movement (%)*	-3.78%	-3.52%	-2.99%	-1.39%	-2.11%	
Smoothed revenue requirement	855.9	857.4	961.7	882.6	904.0	**3,686.6**

* A negative revenue X-factor denotes a real revenue increase.

[9] Rules, cl. 6.5.9(b)(1)

As discussed in the sections below, in proposing X-factors that result in the smoothed revenue profile, we have:

- responded to customer feedback indicating a preference for stable, consistent prices;
- utilised the forecast changes in energy consumption that underpinned our initial proposal;
- sought to minimise the final year difference between smoothed and unsmoothed revenues; and
- incorporated the impacts of the remittal of the 2014-19 determination.

Final year pricing difference 2019-24 period

As mentioned earlier, the Rules require that the difference between smoothed and unsmoothed revenue in the final year of a regulatory control period be as low as reasonably practicable in order to minimise pricing volatility between periods. In the draft decision the AER set X-factors that resulted in a difference of -3.0 percent which we consider to be reasonable.

Consistent with the AER's draft decision, the final year difference between our revised smoothed and unsmoothed revenue in the final year for the 2019-24 period is -3.0 percent.

2.4.2 Indicative bill impacts

Our initial proposal continued our commitment to keeping downward pressure on network prices by locking in a full 10 years of no real DUOS price increase. The AER draft decision made reductions to our proposed revenue requirements which reduced prices further in real terms.

We have accepted most aspects of the AER's draft decision which reflects our commitment to alleviate price pressures and our ongoing effort to be effective and efficient in everything we do, without compromising the safe, sustainable and reliable supply of electricity. As noted above, we have made several amendments to the AER's draft decision to account for the latest available information. Indicative DUOS prices for 2019-24 based on our revised proposed bundled revenue and our latest forecast of energy volumes are provided in table 4 below.

Table 4 - Indicative average annual DUOS for 2018-24 (exclusive of metering)

$; Real 18-19	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Residential customer consuming 5MWh p.a.	502.8	483.9	466.8	452.9	446.6	437.2
Small business customer consuming 10MWh p.a.	862.8	830.2	801.0	777.1	766.3	750.2

The prices outlined above are indicative only and will be updated in our pricing proposal for each year of the 2019-24 period to reflect the:

- AER's final decision on allowed revenue for the 2019-24 period;
- AER's decision on allowed revenue for the remade 2014-19 determination and any differences between this revenue amount and revenue collected under enforceable undertaking arrangements with the AER;
- updated energy consumption forecasts;
- actual CPI;
- updated cost of debt; 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 (NUOS) charge to customers. NUOS charges include the cost of the services provided by the NSW Transmission Network Service Provider (TransGrid) as well as the recovery of an amount to satisfy obligations under the NSW Climate Change Fund (CCF). These components are outside our control.

2.4.3 Formulae to give effect to the control mechanism

We accept the revenue cap control mechanism formula included in the AER's draft decision. However, we do not accept the side constraints formula in its current form.

This is because it is inconsistent with the revenue cap formula. Specifically, it does not include the S factor, or I factor adjustments included in the revenue cap formula. Without these adjustments it is possible that the side constraint formula becomes binding before the revenue cap formula. In this instance we would not be able to recover the efficient costs of providing network services.
We note that elsewhere in the draft decision the AER defines the terms of the side constraint formula including an S factor that does not appear in the formula[10]

We propose that the side constraint formula is updated to include adjustments for the S factor and I factor amounts calculated in the revenue cap control mechanism.

[1010] AER, Endeavour Energy distribution determination 2019-24, Draft decision, Attachment 13, November 2018, p. 15

2.5 Alternative Control Services

In our initial proposal we proposed prices for our public lighting, Ancillary Network Service (ANS) and metering services applying the same pricing methodologies/models from the 2014-19 period. For ANS, an additional pricing model was included to price the newly regulated private security lighting service which had previously been unregulated. These models used the same rate of return, inflation and labour price growth assumptions as contained in our standard control services initial proposal.

2.5.1 Public Lighting

Based on feedback from public lighting customers we proposed a pricing differential be introduced for LED lighting in order to facilitate and encourage the transition to this technology. We proposed to maintain our existing service levels and reduced our forecast revenue requirements by 8 percent.

In its draft decision, the AER has adopted a 20-year standard life assumption for LED lights rather than the 12 years we proposed. Following amendments to the standard control services decision the AER also updated the rate of return, inflation estimate and labour escalation assumptions in our public lighting model. The AER also expressed concerns with the complexity of our model and the confidentiality issues associated with it. Given this, the AER encouraged Endeavour Energy to engage with councils in developing a more transparent and simple public lighting model in the future.

We do not accept a the AER's LED standard asset life assumption of 20 years. We accept that it is difficult to estimate the standard life of these assets given they have not been in service long enough for historical failure rate data to provide a reliable estimation basis. However, we have estimated a revised standard life of 16 years for this revised proposal. This is based on warranty conditions offered by suppliers of LED products which typically include at least a 10 percent failure rate (i.e. a 10 percent failure threshold must be exceeded before it is considered a failure under warranty conditions). It also accounts for the pricing differential we have received from suppliers when requesting a 20-year warranty. In our view a 16-year life better balances the risk of failure and accounts for the limited supplier confidence in the 20-year life.

We accept the AER's draft decision on the rate of return and estimated inflation and have updated it for the final 2018 rate of return instrument. Overall, these amendments will still ensure that public lighting prices will reduce compared to the current period. See Attachment 0.16 for our revised public lighting model and proposed prices.

We also acknowledge the limitations of our existing public lighting model. There is insufficient time available between the AER's draft decision and our revised proposal to develop a new pricing model/approach in consultation with councils. However, we will engage with councils over the course of the 2019-24 period to develop a more transparent, easy-to-use model and pricing approach.

2.5.2 Ancillary Network Services

In our proposal we sought to roll forward the prices from the current period by using the same 18 labour rates and time assumptions for existing services. For new services we selected an applicable labour rate and developed a time assumption based on similar existing services. This was with the exception of private security lighting which is similar to public lighting from a pricing perspective rather than a fee for service pricing approach. Given this, a separate private security lighting pricing model was submitted.

The AER assessed our ANS model based on the implied labour rates by correctly applying the approved x-factors for the 2014-19 period to the rates contained in the model. The AER assessed these labour rates against a series of benchmark rates provided by Marsden Jacobs. Based on this report the AER accepted 5 of the 18 labour rates and reduced the remainder by 9 percent on average. The largest reduction was made to the reconnection/disconnection (meter box) labour rate. Consistent with Marsden Jacob's benchmarking, the AER also reduced labour times for a small number of services.

For the private security lighting model, the AER accepted the assumptions, inputs and prices in both the short and long-term models.

We accept the AER's draft decision including the amendments made to the ANS fee and quoted model. We note that as per previous practice, the AER has used the forecast labour escalator as the pricing x-factor in the ANS model. We have revised the model to incorporate the outcomes of the final rate of return instrument. See Attachment 0.17 for our revised ANS (fee and quoted) model and proposed prices[11].

2.5.3 Metering

In our initial proposal we utilised the model and pricing approach approved for the 2014-19 period to price our type 5 & 6 metering services. We included assumptions in our metering model to account for the impacts of competition in metering services, which commenced 1 December 2017 (with transitional arrangements). This included a forecast metering churn over the 2019-24 period, i.e. the rate at which our metering customer base will transition to smart metering. Also, Energeia provided an estimate of the diseconomy of scale impacts this gradual reduction in customers will have on our metering opex.

In its draft decision the AER accepted several aspects of our metering prices; the pricing approach, the opening RAB, capex forecast and customer churn rate. The AER updated the rate of return, estimated inflation and labour escalation forecast to align these inputs with its standard control services decision. The AER also reduced our proposed metering opex by $4.0 million (real; 2018-19).

While the AER accepted that there would be diseconomies of scale associated with the loss of metering customers they considered the Energeia assumptions require additional justification and questioned whether the assumptions were accurately implemented. Given these concerns the AER examined the historical productivity factors of each NSW DNSP i.e. the rate at which opex changed relative to the rate at which the metering population changed. The AER considered Ausgrid's productivity factor was the most efficient and re-estimated the diseconomies of scale opex impacts on this basis.

We have some concerns with the AER's analysis and its reliance on the Ausgrid productivity factor. However, given it produces an opex estimate that is not materially lower than that proposed in reference to the Energeia assumptions, we accept the AER's draft decision and have updated it for the final rate of return instrument. See Attachment 0.18 for our revised metering model and proposed prices.

[11] With the exception of the Nightwatch models for which we accept the AER's draft decision unamended.

2.6 Implications of other AER Reviews and Guidelines

We note that several inputs to this determination process have been, or remain subject to, separate AER reviews. The ongoing reviews may materially impact the AER's final determination for our 2019-24 revenue requirements.

The following issues have been managed in parallel to this process:

- Rate of Return: the AER commenced its rate of return guideline review on 31 July 2017 and finalised it on 17 December 2018 (14 days prior to the submission of this revised proposal). In addition to this, legislation was introduced in SA Parliament to make this a binding instrument. The rate of return has the single, largest impact on our forecast revenue requirements in the order of 46 percent.
- Productivity: following submissions from stakeholders on the current round of regulatory determinations the AER commenced a process to review its approach to forecasting opex productivity growth. A draft decision was released 9 November 2018 with a final decision to be made sometime after the submission of our revised proposal. This may materially impact our opex forecast which makes up approximately 36 percent of our forecast revenue requirements.
- Tax: the AER commenced a review of its regulatory tax approach on 15 May 2018 following a request from the Federal Minister for the Environment and Energy. A final report on the recommended changes was released 17 December 2018. To give effect to the recommendations of this report, amendments will be required to the AER's regulatory models. This will have a material impact on net tax allowance which makes up approximately 4 percent of our forecast revenue requirements.

We accept that the timing of the rate of return guideline review was made in accordance with the NER and that the AER is responding to the direction and feedback it receives from the Federal Minister for the Environment and Energy and stakeholders. However, from a procedural perspective we have concerns with the timing of these reviews and our ability to engage, particularly with the tax and productivity reviews which have commenced during this determination process and conclude after our revised proposal is submitted and submissions on the AER's draft decision and our revised proposal close.

In developing our initial and revised proposals we have had to commit to a position on the outcomes of yet to be completed reviews which have a material impact on our overall revenue allowance. We have been criticised by some stakeholders for not applying draft and incomplete guidelines rather than the prevailing guidelines as previously agreed with stakeholders prior to the commencement of guideline reviews. We also consider agreeing to unresolved matters undermines our ability to respond meaningfully in the separate reviews.

Our forecast revenue requirements are assessed with regard to the National Electricity Objective and the Revenue and Pricing principles. Essentially, individual building block components are assessed against specific criteria in the NER and the sum total of that process is then assessed against the NEO and RPP. It is therefore difficult for us to forecast our revenue requirements with certainty and then justify the forecast as an efficient allowance that best serves the long-term interests of customers when approximately 86 percent of it is subject to separate, ongoing (or recently finalised) reviews. The impacts (if applied) of these reviews may result in changes to our revenue forecast that would change our view as to whether the overall revenue allowance is efficient and satisfies the NEO and RPP.

This creates a significant degree of investment uncertainty which may seriously hamper our ability to raise an efficient level of capital at efficient rates to keep costs for our customers down. It is important that there is timely and transparent engagement on critical issues and that sufficient time is available to properly consider them and then properly account for them in a determination process. Our concern is that some of the current reviews have been expedited so that they apply to the current determinations when more detailed consideration is required.

Amended STPIS

The AER commenced a review of the STPIS and DRMG on 5 January 2017. A draft decision was released 14 December 2017 before a final STPIS amendment and DRMG on 14 November 2018. The amended STPIS provides for AER discretion in managing the transition between version 1 and 2 of the scheme between regulatory control periods. Additionally, in the final F&A decision the AER noted that the NSW DNSPs may need to apply the revised STPIS depending on when it was completed[12]. The AER's draft decision confirmed the F&A decision noting that the revised STPIS was not yet complete at that point in time[13].

There are some aspects of the AER's discretion in departing from the F&A decision that are limited by the Rules (cl 6.12.3). We do not consider the AER's decision on the application of incentive schemes is subject to this restriction. Even if it were, there has been a material change in circumstances, namely the publication of an amended guideline, which justifies a departure from the F&A decision.

There are also restrictions on what matters we can raise in a revised proposal (NER cl 6.10.3). The AER has consistently made reference to the STPIS and DRMG reviews and prefaced its decision to apply version 1 of the STPIS on the unavailability of the amended STPIS. On this basis, it is our view that this matter has been raised and maintained throughout the determination process to date and it can therefore be addressed as part of our revised proposal.

The amendments made to the STPIS and DRMG were done so to improve the incentive scheme and the measurement of reliability in order to improve customer outcomes. From a procedural perspective this guideline review differs from the other reviews discussed above as it commenced prior to the completion of the F&A process for the 2019-24 determinations. Additionally, a draft decision was available well in advance of our initial proposal so that our plans were developed in consideration of the proposed changes. The changes consulted on were generally well accepted by both networks and stakeholders and the final decision does not differ materially from the draft decision. It is also our understanding that our jurisdictional regulator will amend our licence conditions to adopt the AER's newly defined momentary interruption threshold.

Given this, and our view that the issue is open for revision, we propose that the updated DRMG and version 2 of the STPIS are applied to us for the 2019-24 period. We have provided the re-cast historical information the AER requires to apply the amended STPIS in Attachment 0.09 to this revised proposal. We note that this data was not auditable in the time available to submit our revised proposal, an audit opinion confirming the accuracy of this data will be provided post-submission.

[12] AER, Framework and Approach - Ausgrid, Endeavour Energy and Essential Energy Regulatory control period commencing 1 July 2019, Final decision, July 2017, p. 61
[13] AER, Endeavour Energy distribution determination 2019-24, Draft decision, Attachment 10, November 2018, p. 6

Glossary

TERM	DEFINITION
ABR	Annual Benchmarking Report
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AER CCP 10	Australian Energy Regulator’s Consumer Challenge Panel
ANS	Ancillary Network service
ARR	Annual Revenue Requirement
Capex	Capital Expenditure
CCF	Climate Change Fund
CESS	Capital Efficiency Sharing Scheme
CPI	Consumer Price Index
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAPR	Distribution Annual Planning Report
DMIA	Demand management innovation allowance
DMIS	Demand management incentive scheme
DNSP	Distribution network service provider
DRED	Demand response enabling devices
DUOS	Distribution use of system
EBSS	Efficiency benefit sharing scheme
EGWWS	Electricity, Gas, Water and Waste services
ENA	Energy Networks Australia
F&A	Framework and approach
GWh	Gigawatt Hour
ICT	Information and Communications Technology
kV	Kilovolt
kWh	Kilowatt Hour
LED	Light-emitting diode

MAR	Maximum Allowable Revenue
MED	Major Event Day
MRP	Market risk premium
MVA	Mega Volt Amperes
MWh	Megawatt Hour
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NSW	New South Wales
NUOS	Network use of system
Opex	Operating expenditure
PTRM	Post tax revenue model
RAB	Regulatory asset base
RFM	Roll-forward model
Rules	National Electricity Rules
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
STPIS	Service target performance incentive scheme
TOU	Time of Use
TSS	Tariff Structure Statement
UDIA	Urban Development Institute of Australia
WACC	Weighted Average Cost of Capital
WPI	Wage Price Index
WSA Co	Western Sydney Airport corporation

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Produced by
Endeavour Energy – Network Regulation Branch

Head Office
51 Huntingwood Drive
Huntingwood NSW 2148
PO Box 811, Seven Hills NSW 1730

Phone
131 081 or (02) 9853 6666
(8.00am – 5.30pm Monday to Friday)

Fax
(02) 9853 6000

Email
ENDV19-24Determination@endeavourenergy.com.au