Draft decision

Essential Energy distribution determination

2015–16 to 2018–19

Overview

November 2014

AUSTRALIAN ENERGY REGULATOR

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Note

This overview forms part of the AER's draft decision on Essential Energy's 2015–19 distribution determination. It should be read with other parts of the draft decision.

The draft decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

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Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

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Shortened forms

Shortened form	Extended form
AARR	aggregate annual revenue requirement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASRR	aggregate service revenue requirement
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
CPI-X	consumer price index minus X
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
expenditure assessment guideline	expenditure forecast assessment guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium

Shortened form	Extended form
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

1 Our draft decision

Essential Energy is one of three distribution network service providers (DNSPs) in New South Wales. We, the Australian Energy Regulator (AER), regulate the revenues of Essential Energy and other DNSPs in the national electricity market (NEM).

This is one of the first draft decisions we have made following changes to the National Electricity Rules (NER) and National Electricity Law (NEL) in 2012 and 2013. The amended NER encourages us to approach decision making more holistically, with a greater emphasis on the efficient costs of providing network services. As part of our Better Regulation program, which we started in 2012, we developed more sophisticated tools with which we can assess efficient costs. Our Better Regulation program emphasised the importance of transparency and consultation in making our decisions.

This draft decision is one of the key steps in reaching our final decision. Our final decision will be released in April 2015. Before that, Essential Energy will have the opportunity to submit a revised proposal in response to this draft decision. Stakeholders will also have the opportunity to make submissions on our draft decision and Essential Energy's revised proposal. While we welcome submissions on any aspects of this draft decisions, we have highlighted certain areas where we are particularly interested in hearing stakeholders' views. Following receipt of the revised proposal and submissions, we will then make our final decision taking everything we have heard into account.

We have made a draft decision on the revenue that Essential Energy may recover from its customers in the upcoming 2015–19 regulatory control period. In total, our draft decision provides an allowance of $3678.6 million ($ nominal). This allowance represents a reduction of around 33.9 per cent compared to Essential Energy's proposal.

Distribution charges represent approximately 43 per cent, on average, of the annual electricity bill for Essential Energy customers. If the lower distribution charges from our draft decision are passed through to consumers, we would expect the annual electricity bill for a typical residential customer to reduce on average by $346 in 2015–16, all else being equal. This compares with a typical bill increasing on average by $157 in 2015–16 under Essential Energy's proposal. Further details can be found in chapter 7 of this Overview.

If we had accepted Essential Energy's proposal, Essential Energy would have been permitted to recover $5561.6 million ($ nominal) from customers over the 2015–19 regulatory control period.[1] We are not satisfied that Essential Energy's proposed revenue would "contribute to the achievement of the National Electricity Objective (NEO) to the greatest degree" as required by the rules.

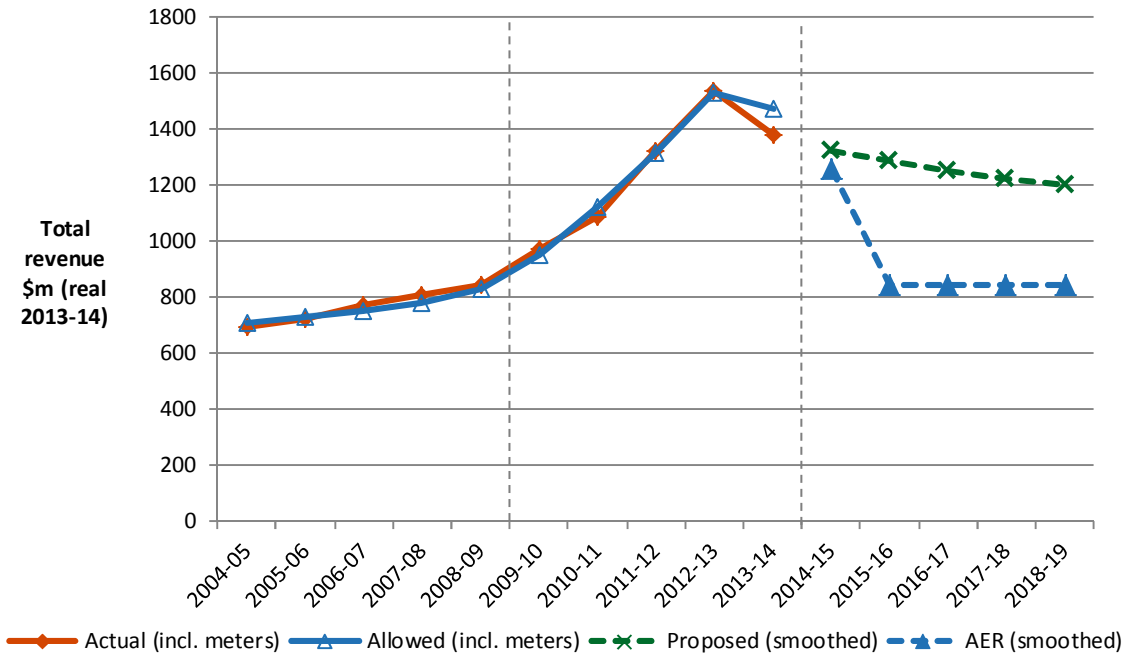
This document provides the reader with an overview of our draft decision. It offers an insight into the issues we considered, the conclusions we made and how those conclusions were reached. Detailed reasons for each of the elements of our decision can be found in attachments and appendices accompanying this decision.

Essential Energy's regulatory proposal puts forward revenue broadly in line with its current levels. The total revenue we propose to allow in this draft decision reflects the underlying drivers of the costs of providing distribution services in Essential Energy's network area. Specifically, circumstances have changed since the last regulatory period such that there has been a material easing in the pressure

[1] Essential Energy's proposal did not take account of the transitional placeholder revenue for 2014–15. The proposed amount has been adjusted to reflect the true-up for the placeholder revenue.

on costs since we made our last determination in 2009. Consequently, our draft decision provides for less revenue (on average) than what was approved in the last period. Figure 1-1 shows Essential Energy's past total revenue (both allowed and actual),[2] proposed total revenue and our draft total revenue allowance.[3]

Figure 1-1 Essential Energy's past total revenue, proposed total revenue and AER total revenue allowance ($ million, 2013–14)



Source: AER analysis.

The underlying drivers of the costs of providing network services in Essential Energy's network area that are reflected in this draft decision include the following:

- Efficiency. Our assessment of Essential Energy's proposal shows that there are opportunities for Essential Energy's network services to be provided more efficiently. Essential Energy itself has identified inefficiencies in its business practices and proposed measures to reduce its costs going forward. Our benchmarking work (outlined in attachment 7) highlights the extent of efficiencies that are available.
- Better risk assessment. In the course of our review of Essential Energy's proposal we have come to the view that Essential Energy's risk management practices are overly risk averse and result in higher capital expenditure forecasts than what is necessary.
- Demand. At the time of making our last determination in 2009, demand for electricity was expected to increase. However, these forecast increases did not eventuate. System peak demand in Essential Energy's network decreased on average by around 1.13 per cent per annum over the past five years. Recent forecasts suggest that the trend will continue downwards, at least for the

[2] The actual for 2013–14 is an estimate provided by the service provider.
[3] The draft decision revenue for 2014–15 is based on the AER's placeholder decision for this year made under the transitional rules.

next few years. This implies that Essential Energy is under less pressure to expand its network. These expectations suggest that only modest amounts of growth related expenditure will be required in the forthcoming period.

- Financial market conditions. The investment environment has improved since our previous decision. That decision, in 2009, was made at the height of uncertainty surrounding the global financial crisis. Interest rates and risk premiums are now materially lower than in 2009.

Our analysis has taken these underlying drivers into account and this is reflected in the total revenue allowance we have calculated. The total allowed revenue we have determined is broadly in line with the trend in revenue that was allowed in the 2004–09 regulatory period. In 2009, there were a range of pressures that led to a step up in total allowed revenue. This draft decision reflects an easing in many of the underlying drivers that influenced the revenue outcome in 2009. By contrast, we have found that Essential Energy's proposal does not adequately incorporate these underlying drivers.

We have had an unprecedented level of consumer participation in our decision making process. Stakeholders, including both businesses and consumer advocates, have been telling us that Essential Energy's proposal does not adequately incorporate their views and is not in the long term interests of consumers. We have taken all submissions from stakeholders into account in reaching our draft decision.

Transition to efficient operating expenditure

One further issue we address in this draft decision is whether it is appropriate to allow Essential Energy to transition over time from its current level of operating expenditure to what we have determined as efficient expenditure. If such a need can be demonstrated to be consistent with the NEL, the NER and the NEO, the question that then arises is how this transition should be funded. That is, should consumers be asked to share the costs associated with transitioning to efficiency and, if so, how.

Essential Energy has acknowledged its current practices and expenditures are inefficient and has demonstrated it is taking steps to these inefficiencies. Essential Energy submits, however, that given the impact this process will have on its business, the process of transitioning will take time, particularly given legal obligations arising from its enterprise agreement.[4] This is reflected in Essential Energy's operating expenditure proposal, which is at a similar level to what it spent during the 2009–14 period.

We expect all service providers to comply with their legal obligations, whether those obligations arise in legislation, contract, or some other legal duty. Service providers must comply with, for example, the Fair Work Act 2009 and other relevant laws in providing their services. However, we find that the presence of a legal obligation, by itself, is insufficient to justify us providing operating expenditure for a particular item. Service providers undertake many significant activities by agreeing to enter into legally binding arrangements. Enterprise agreements are one example of this. If a contractual or legal obligation was sufficient to justify the provision of operating expenditure, it would curtail the scope for us to undertake efficiency assessments. Put differently, the costs of a contract that incorporated inefficient expenditures would be passed through to consumers if we were unable to assess efficiency. Such an approach is more in keeping with a cost of service model rather than the efficiency based regulatory regime under which we operate.

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[4] See, for example, NSW DNSPs, *Submission on AER issues paper*, August 2014, pp. 12–16.

Also, we determine a service provider's operating expenditure allowance at the total level. We do not seek to interfere in the decisions a service provider will make about how and when to spend this total operating expenditure allowance to run its network, including the particular legal obligations it enters into to do so. The service provider is free to choose how to manage the operating expenditure our decision allows for.

We are encouraged by Essential Energy's effort to take the necessary steps to improve its efficiency. However, we consider its proposed operating expenditure allowance is above the level required by a prudent operator to meet its obligations under the NEL and the NER. Therefore, we have not accepted Essential Energy's proposed total operating expenditure allowance and have substituted an allowance that we are satisfied reasonably reflects the following criteria from the NER:[5]

(1) the efficient costs of achieving the operating expenditure objectives; and

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

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

Based on the information before us, we are not satisfied that Essential Energy has made a sufficiently robust argument for why consumers should share in funding Essential Energy's transition to an efficient level of operating expenditure. Moreover, it is not clear from the information before us that this is consistent with the incentive framework provided by the NEL and the NER. This is not an issue we have canvassed fully with stakeholders to date. We welcome submissions on this issue and will consider this issue further in view of any submissions received.

Key constituent decisions

Our draft decision is predicated on a number of constituent decisions.6 We list our constituent decisions in appendix A to this overview. Three of the key constituent decisions include:

- Rate of return. We are not satisfied that Essential Energy's proposed 8.83 per cent rate of return is such that it achieves the allowed rate of return objective. We have therefore not accepted Essential Energy's proposal. The NER defines the rate of return objective as follows: that the rate of return is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to Essential Energy in respect of the provision of many network services.[7] Using our rate of return guideline as our starting point, we have allowed a rate of return of 7.15 per cent (nominal vanilla) that achieves the rate of return objective and will allow Essential Energy to fund its efficient network investment.

- Operating expenditure. We are not satisfied that Essential Energy's proposed forecast operating expenditure of $2331.8 million ($2013–14) reasonably reflects the operating expenditure criteria. We have therefore not accepted Essential Energy's proposal. Our alternative estimate of Essential Energy's total forecast operating expenditure for the 2014–19 period that we are satisfied reasonably reflects the opex criteria is $1436.5 million ($2013–14).[8] The main driver for

5 NER, cl. 6.5.6(c), 6.5.7(c).
6 NER, cl. 6.12.1.
7 NER, cl. 6.5.2(b).
8 Includes debt raising costs.

our substitute operating expenditure forecast is our alternative estimate for what we consider represents an efficient base level of operating expenditure.

- Capital expenditure. We are not satisfied that Essential's proposed total forecast capital expenditure of $2618.7 million ($2013–14) reasonably reflects the capital expenditure criteria. We therefore have not accepted Essential's proposal. Our alternative estimate of Essential's total forecast capital expenditure for the 2014–19 period that we are satisfied reasonably reflects the capital expenditure criteria, is $1934.3 million. The main driver for our substitute capital expenditure forecast is our reduction in the amount of forecast replacement expenditure.

We are satisfied that our draft decision an appropriate balance between the efficient investment operation and use of electricity services that contribute to the achievement of the NEO. We are satisfied the overall revenue allowance we propose for Essential Energy provides a return sufficient to promote efficient investment, while also providing Essential Energy with incentives to operate its network more efficiently.

2 About our draft decision – context and framework

The NEL anticipates that there may be two or more possible overall outcomes that will or are likely to contribute to the achievement of the NEO. In those cases, we must make the decision we are satisfied will contribute to the achievement of the NEO to the greatest degree.[9]

This overview sets out why we are satisfied that our draft decision will contribute to the achievement of the NEO to the greatest degree.[10] Specifically, we address section 16 of the NEL which sets out how we must exercise our regulatory functions and powers. This overview sets out our holistic analysis. The Australian Energy Market Commission (AEMC) and Ministers considered taking a more holistic approach is essential to our task, under the regulatory and limited merits review regimes.[11] The attachments and appendices that follow the Overview include more specific detailed analysis for each constituent component of this draft decision. This Overview is based on that detailed analysis, especially in identifying key interrelationships that drive our overall decision.[12]

The NEL and the NER provide the legal framework under which we operate. The NEO is the central feature of the legal framework. The NEO is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—

> price, quality, safety, reliability and security of supply of electricity; and
>
> the reliability, safety and security of the national electricity system.[13]

The NEL also includes the revenue and pricing principles (RPP), which support the NEO.[14] As the NEL requires,[15] we have taken the RPPs into account throughout our analysis. The RPPs are:

> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in—
>
> - providing direct control network services; and
> - complying with a regulatory obligation or requirement or making a regulatory payment.
>
> A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
>
> - efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
> - the efficient provision of electricity network services; and
> - the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
>
> Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted—

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9 NEL, s. 16(1)(d).

10 For the reasons set out throughout this decision, we do not consider Essential Energy's proposal would contribute to the achievement of the NEO. Therefore, we do not need to address s. 16(1)(d) of the NEL. However, in any case, our reasoning demonstrates that we are also satisfied that our draft decision would contribute to the achievement of the NEO to a greater degree than Essential Energy's proposal.

11 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* pp. xi, 10, 19, 35, 148.

12 See especially sections 5 and 6 below.

13 NEL, s. 7.

14 NEL, s. 7A.

15 NEL, s. 16(2).

- in any previous—
- as the case requires, distribution determination or transmission determination; or
- determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or
- in the Rules.

A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.

We regulate distributors' revenue allowances for providing electricity network services in the NEM. The NEL and NER operate to allow a distributor a reasonable opportunity to recover at least efficient costs. We set revenue allowances to balance all of the elements of the NEO and RPPs, consistent with Ministers' view that all of these principles are equally vital.[16] The revenue allowance determines the amount that distributors can recover from customers through network charges.

Chapter 6 of the NER provides specifically for the economic regulation of distributors. It includes detailed rules about the constituent components of our decisions, which are intended to contribute to the achievement of the NEO.[17]

Given this legislative framework, we consider the NEO and how to achieve it throughout our decision making processes.

2.1 Structure of our draft decision

Our draft decision consists of two parts:

Part A: Overview

This Overview sets out why we consider our overall draft decision contributes to the achievement of the NEO to the greatest degree. The Overview:

- states our draft decision to reject Essential Energy's proposal and the total revenue allowance we propose to approve
- outlines the context and framework of our decision. It discusses the NEO18 and section 16 of the NEL, being the manner in which we must perform our economic regulatory functions and powers
- sets out the reasons for our overall decision, including why we consider our approach will, or is likely to, contribute to the achievement of the NEO.

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16 Hansard, SA House of Assembly, 27 September 2007 pp. 965

17 NEL, s. 88.
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* p. 8.

18 NEL, s. 16.

Part B: Attachments

Our attachments support the overview by setting out:

- our detailed analysis of Essential Energy's regulatory proposal and our detailed reasons for developing an alternative total revenue allowance, by building block and why we are satisfied that our decision, as a whole, contributes to the achievement of the NEO
- our demonstrated account of the revenue and pricing principles
- the constituent components of our draft decision.

2.2 What is different about this decision?

This is the first draft decision we have made following changes to the NEL and NER in 2012 and 2013. The NEL and NER were changed to provide greater emphasis on the NEO and greater discretion to us.[19] The amended NER allows and encourages us to approach decision making more holistically to meet overall objectives consistent with the NEO and RPPs.[20] These changes also sought to give consumers a clearer and more prominent role in the decision making process.[21]

In 2013, the NEL was changed with similar aims in mind. Energy Ministers intend that the long term interests of consumers should be a key focus in determining our decision.[22] The changes also encourage analysis of the decision as a whole in light of the NEO when making constituent decisions.[23]

These legislative changes have made this decision different from our previous decisions. In particular, for the first time, we have specifically assessed our overall revenue decision and its contribution to the achievement of the NEO.[24] We consider this is an appropriate change as we determine an overall revenue allowance.[25] We do not seek to interfere in the decisions a service provider will make about how and when to spend the total capex or opex allowance to run its network. The service provider is free to choose how to manage its allowance. For example, we do not approve individual capital expenditure projects that a distributor must then implement. Rather, we determine the sum total of revenue that we consider satisfies the requirements of the NEL and NER.[26] Consistent with incentive regulation, it is then for the distributor to determine the particulars of how this allowance is applied in the next regulatory control period (usually five years). As the overall revenue allowance is the key

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19 NEL, ss. 16(1)(d) and 71P(2a)(c).
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, pp. i, iii, iv, vi, vii, 8, 24 32, 36, 38, 45, 49, 67, 68, 90, 96 106, 112 and 113.
Hansard, SA House of Assembly, 26 September 2013 p. 7172.

20 For example, NER, cl. 6.5.2(b) and (c), 6.5.6(a) and 6.5.7(a).
AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, pp. xi, 10, 19, 32 and 35.

21 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, esp. pp. 166–170.

22 Hansard, SA House of Assembly, 26 September 2013 p. 7171.

23 NEL, ss. 2, 16, 71A and 71P which focus the AER's decision making and merits review at the overall decision, rather than its constituent components.
Hansard, SA House of Assembly, 26 September 2013 pp. 7171 and 7173; See also NEL, ss. 2, 16 and 71A which focus the AER's decision making and merits review at the overall decision, rather than its constituent components.
SCER, *Regulation Impact Statement – Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks*' 6 June 2013 pp. i, ii, 6–7, 10, 36, 41 and 76.

24 See sections 5 and 6.

25 NEL, ss. 2, 16, 71A and 71P.

26 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012,* esp. p. vii

binding feature of our draft decision, it is important that we specifically assess its contribution to the achievement of the NEO.

2.3 Understanding the NEO

The NEO is to promote three factors for the long term interests of consumers:

- efficient investment in
- efficient operation of
- efficient use of;

electricity services.

Energy Ministers have provided us with a substantial body of analysis and explanation that guides our understanding of the NEO.[27] The long term interests of consumers are not delivered by any one of the NEO's factors in isolation, but rather by balancing them.[28]

In general, we consider that we will achieve this balance and, therefore, contribute to the achievement of the NEO where consumers are provided a reasonable level of service at the lowest sustainable price.[29] In most industries, competition creates this outcome. Competition drives suppliers to develop their offerings to attract customers. Where a supplier's offering is not attractive it risks being displaced by other suppliers.

However, in the energy networks industry the usual competitive disciplines do not operate. The distributors are largely natural monopolies. Many of the products they offer are essential services for most consumers. Consequently, in an uncompetitive environment, consumers have little choice but to accept the quality and price the distributors offer.

The NEL and NER aim to remedy the absence of competition by empowering us, as regulator, to make decisions that are in the long term interests of consumers. In particular, we might need to require the distributors to offer their services at a different price than they would choose themselves. By its nature, this process will involve exercising regulatory discretion to balance the NEO's various factors.

It is important to recognise that there is no sole correct answer that will solely contribute to the achievement of the NEO. The nature of decisions in the energy sector is such that there may be a range of economically efficient decisions, with different implications for the long term interests of consumers.[30] At the same time, however, there are a range of outcomes that are unlikely to advance the NEO to a satisfactory extent. For example, we do not consider that the NEO would be advanced if allowed revenues encourage overinvestment and result in prices so high that consumers are unwilling or unable to efficiently use the network.[31] This could have significant longer term pricing implications for those consumers who continue to use network services. Equally, we do not consider the NEO would be advanced if allowed revenues result in prices so low that investors are unwilling to invest as

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27 Hansard, SA House of Assembly, 9 February 2005 pp. 1451–1460.
Hansard, SA House of Assembly, 27 September 2007 pp. 963–972.
Hansard, SA House of Assembly, 26 September 2013 pp. 7171–7176.

28 Hansard, SA House of Assembly, 26 September 2013 p. 7173.

29 Hansard, SA House of Assembly, 9 February 2005 p. 1452.

30 *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].
Energy Ministers also accept this view – see Hansard, SA House of Assembly, 26 September 2013 p. 7172.

31 NEL, s. 7A(7).

required to adequately maintain the appropriate quality and level of service, creating longer term problems in the network.[32] This can have adverse consequences for safety, security and reliability of the network.

2.4 The transitional and subsequent regulatory control periods

In November 2012, the Australian Energy Market Commission (AEMC) introduced major changes to the economic regulation of DNSPs under chapter 6 of the NER (the new rules).[33]

Prior to the making of the new rules, distribution determinations for the NSW/ACT distributors were due to commence on 1 July 2014 and would apply for a period of five years. However, the process was delayed so consumers would receive the benefit of the new rules.

To allow for an expedited transition to the new rules, the AEMC made transitional rules in chapter 11 of the NER under which there would be two regulatory control periods to cover the period from 2014-19:[34]

- a regulatory control period covering the period 1 July 2014 to 30 June 2015, referred to in the NER as 'the transitional regulatory control period', and
- a regulatory control period beginning 1 July 2015 referred to in the NER as 'the subsequent regulatory control period'.[35]

For the transitional regulatory control period, we made a fast-tracked placeholder determination on 16 April 2014 for each of the NSW/ACT distributors. In that determination we were not satisfied with the proposed annual revenue requirement for the transitional regulatory control period and instead approved an alternative annual revenue requirement by adjusting a limited number of inputs to the distributors' proposals. We approved this as a placeholder revenue allowance that would later be 'trued-up' in our determination for the 2015–19 regulatory control period.

A more detailed explanation of our placeholder determination and a description of how we apply the true up is set out in appendix B.

Rules applicable to this decision

We assessed Essential Energy's regulatory proposal under a modified version of Chapter 6 of the NER, in accordance with clauses 11.55-11.56 of the NER. Clause 11.56.5 of the Transitional Rules outlines that we are excluded from conducting an ex post review of capital expenditure incurred in the 2009–14 regulatory control period.[36] This means we are not permitted to adjust the opening RAB for any inefficient capex (as assessed to reasonably reflect the capex criteria and in a manner consistent with the capex objectives) during the 2009–14 period. However, historical capex and opex does inform our assessment of expenditure forecasts.

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32 NEL, s. 7A(6).
33 AEMC Final Rule Determination, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012 (AEMC Final Rule Determination).
34 NER, Chapter 11, Savings and Transitional Rules, Part ZW Economic Regulation of Network Service Providers (2012 amendments).
35 NER, cl.11.55.1 definitions.
36 NER, schedule 6A.2.2A, cl. 11.58.5

3 Our approach to this decision and why it contributes to the achievement of the NEO

We must perform our functions in a manner that will or is likely to contribute to the achievement of the NEO.[37] This section focuses on the manner in which we have made this draft decision. Section 4 of this Overview discusses material issues and shows how we take account of stakeholder views. Section 3 and 4 are largely about our process in line with section 16(1)(a) and (b) of the NEL.

Sections 5 and 6 focus more on the outcome of our decision. Section 5 explains how we have taken into account interrelationships between constituent components of our decision. Section 6 explains why we consider our decision is preferable, in that it contributes to the achievement of the NEO to the greatest degree.

3.1 Better Regulation program

Following the 2012 changes to the NER, we spent much of 2013 consulting on and refining our assessment methods and approaches to decision making. We referred to this as our Better Regulation program. The objective of this program was to refine our approaches, with a greater emphasis on incentive regulation.[38] The resulting guidelines support our decision making framework as set out in section 16 of the NEL.

The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged and provide their input.[39] We tested our views and heard from the full range of stakeholders. Our consultation and engagement gives us confidence the approaches set out in the guidelines will result in decisions that contribute to the achievement of the NEO and form an important baseline in future decision making. In particular, we directly engaged consumers in the process through our Consumer Reference Group.[40] We facilitated direct engagement between network service providers and consumers through participation in forums and the almost 140 meetings held with stakeholders over the course of the program.[41] Consumers and network service providers also filed written submissions on our draft guidelines and explanatory statements, responded to advice from our experts and provided their own consultant reports.

One of the themes that emerged from our consultation was a desire from stakeholders for clarity about the approach we would take in our decisions. In particular, many stakeholders observed that greater clarity would aid investment in the sector.[42]

During our consultation processes, there were differences of opinion, particularly between network businesses and consumers. Often there was no consensus. In such cases, we determined an outcome that we were satisfied would best balance competing interests and the range of factors in the NEL and NER that contribute to the NEO. These outcomes went some way to satisfying all parties. But, often, they were neither the network businesses' nor consumers' preferred outcome. Section 16 of the NEL recognises that the regulatory framework allows for potentially more than one outcome.

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37 NEL, s. 16(1)(a).
38 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.
39 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.
40 AER, *Assessment of the Consumer Reference Group*, March 2014. This document includes information on training provided to CRG members, meetings and CRG member feedback. It can be accessed at www.aer.gov.au/node/19166.
41 AER, *Overview of the Better Regulation reform package*, April 2014, pp. 20–21.
42 See for example – AER, *Rate of Return Guideline*, December 2013 pp. 25 and 66.

We consider that the guidelines that resulted from our engagement with all stakeholders provide a solid foundation for our decision making.

The guidelines we developed include:

- Expenditure forecast assessment guideline – describes the process, techniques and associated data requirements for our approach to setting efficient expenditure allowances for network businesses
- Expenditure incentives guideline – sets out our capital expenditure incentives and efficiency benefit sharing schemes which are designed to give electricity network businesses incentives to spend efficiently and share the benefits of efficiencies with consumers
- Rate of return guideline – sets out how we determine the return that network businesses can earn on their investments. Applied consistently over time, the guideline provides regulatory stability and increased certainty through greater transparency of the key components of the rate of return and how these are assessed.
- Consumer engagement guideline for network service providers – aims to help network businesses develop strategies to engage systematically, consistently, effectively and strategically with consumers on issues that are significant to both parties
- Shared assets guideline – outlines how consumers will benefit from the other services electricity network businesses may provide using the assets consumers pay for
- Confidentiality guideline – sets out how network businesses must make confidentiality claims over information they submit to us. This guideline balances protecting genuinely confidential information with ensuring that stakeholders can access sufficient information on issues affecting their interests.

Our guidelines are available on our website[43], and summarised in appendix C.

[43] http://www.aer.gov.au/Better-regulation-reform-program

4 Material issues and opportunity to be heard

The NEL requires us to inform stakeholders of the material issues we are considering and to give them a reasonable opportunity to make submissions in respect of this decision.[44]

The starting point for our draft decision was to assess Essential Energy's regulatory proposal against the NEL and the NER.[45] In doing so, we applied our guidelines and assessment tools, as appropriate, and gathered submissions from stakeholders. We considered Essential Energy's regulatory proposal in light of submissions, its performance to date and its operating environment. A high level overview of these processes follows. Further information on how we informed stakeholders of material issues and provided a reasonable opportunity to make submissions is at appendix D. A list of stakeholder submissions is in appendix E.

4.1 Our engagement

Effective consultation with stakeholders is essential to the performance of our regulatory functions. . In summary, throughout the review process, we engaged with stakeholders by:

- holding monthly meetings with Essential Energy to discuss issues relevant to this decision. These meetings commenced in October 2011 to discuss the framework and approach. The meetings continued throughout our decision making process.
- establishing the Consumer Challenge Panel (CCP) to assist us to make better regulatory determinations by providing input on issues of importance to consumers
- considering 50 submissions on Essential Energy's regulatory proposal
- publishing an issues paper to help stakeholders engage with, and meaningfully respond to issues in Essential Energy's regulatory proposal that we considered material to consumers
- hosting a public forum in Sydney on 10 July 2014 so stakeholders could question the AER, the CCP and Essential Energy on its regulatory proposal
- having Essential Energy present its revenue proposal to the AER Board on 1 August 2014, so questions could be raised and key issues explained
- having the CCP present its advice in response to Essential Energy's regulatory proposal to the AER Board on 5 August 2014
- convening monthly meetings between the CCP and AER staff to discuss key issues
- ongoing formal and informal jurisdictional consumer forums from February 2012
- consulting on benchmarking measures prepared by us and Economic Insights, jointly relevant to the preparation of the annual benchmarking report and our assessment of Essential Energy's regulatory proposal
- having ongoing discussions with Essential Energy about its regulatory proposal. In particular, our consultants and AER staff met with Essential Energy to discuss operating expenditure,

[44] NEL, s. 16(1)(b).
[45] AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012 National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 29 November 2012, p. 111.

augmentation capital expenditure, and replacement capital expenditure. During this process, AER staff and our consultants considered over 40 responses to information requested from Essential Energy.

- hosting a workshop on treatment of metering exit fees on 11 September 2014
- meeting with the NSW Public Interest Advocacy Centre and other stakeholders to discuss their submissions in detail.

We investigated Essential Energy's proposal by engaging with our consultants and visiting Essential Energy at its offices. AER staff, including our technical advisors and EMCa directly engaged with staff at Essential Energy involved in developing and managing the network, and tested material and information which underpins its revenue proposal.

4.1.1 Our issues paper

We published an issues paper to help stakeholders engage with, and meaningfully respond to, issues in Essential Energy's regulatory proposal that we considered material to consumers. Under the transitional rules, we were not required to prepare an issues paper.[46] However, we thought it was important to provide a guide to stakeholders on key issues and where they could focus their responses in light of more than 14 300 pages of material Essential Energy submitted.[47] We therefore structured our issues paper by providing a high level perspective on Essential Energy's proposal and our initial observations followed by some analysis around key drivers of Essential Energy's proposal.[48]

4.1.2 Outcome of submissions

Most submissions considered Essential Energy's regulatory proposal is not in the long term interests of consumers and recommended that we should reject the proposal. A list of all submissions is at appendix E.

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46 NER, cl. 6.9.3(b)–(b), however cl. 11.56.4(o) did not require us to publish an issues paper for this determination.

47 Essential Energy, *Confidentiality template*, May 2014. The figure listed above is the number of pages in the proposal that did not contain confidential information. Including confidential information, Essential Energy's proposal totalled 15 209 pages.

48 AER, *Issues paper NSW electricity distribution regulatory proposals 2014–19*, July 2014. A copy is available at http://www.aer.gov.au/node/11483.

5 Constituent components and interrelationships

The NEL requires us to specify how the constituent components of our decision relate to each other and how we have taken those interrelationships into account in making our decision.[49] We consider this appropriate. When considering any constituent component of a decision as complex as a distribution determination, it is important to also consider the interrelationships between constituent components. Ultimately, a distribution determination is an overall decision and must be considered as such. Considering constituent components in isolation ignores the importance of these interrelationships, would not contribute to the achievement of the NEO and, in the past, has resulted in regulatory failures.[50]

Interrelationships can take various forms including:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period and it also affects how overall revenue is translated into individual prices.
- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall Vanilla WACC.
- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex and vice versa.
- trade-offs between forecast and actual regulatory measures. The reasons for one part of a proposal may have impacts on other parts of a proposal. For example, an increase in augmentation to the network means the distributor has more assets to maintain leading to higher opex requirements.
- the distributor's attitude to managing its network. The distributor's governance arrangements and its approach to risk management will influence most aspects of the proposal, including capex/opex trade-offs.

Interrelationships are also a useful tool when approaching decision making more holistically. This is especially the case for underlying drivers that are likely to affect many aspects of revenue simultaneously. In these cases, individual drivers may influence the overall efficient revenue allowance. As a result, while there is no tool to directly estimate an efficient overall revenue allowance, underlying drivers can indicate the direction and broad magnitude of changes to the efficient level of overall revenue.

Consumer preferences should also be reflected throughout the proposal. More particularly, if the distributor states investment is needed because consumers want it, the distributor needs to show that is has effectively engaged with consumers to evidence this is the case. Any deficiency in consumer engagement will mean consumer views will be reflected less in the proposal. This is likely to impact most aspects of the proposal.

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[49] NEL, s. 16(c).

[50] SCER, *Regulation Impact Statement: Limited Merits Review of Decision-Making in the Electricity and Gas Regulatory Frameworks – Decision Paper*, 6 June 2013 p. 6

5.1 Key drivers impacting revenue

Below, we summarise the key underlying drivers for this decision and illustrate their impact on the constituent components of our decision. We then examine the cumulative effect of these drivers on the efficient level of overall revenue. In our attachments and appendices we include our analysis of the other interrelationships between constituent components of this decision.

Efficiency of past expenditure

A starting point for assessing whether the proposal submitted by Essential Energy is based on efficient costs is to carefully examine its previous expenditure.

Our assessment of Essential Energy's past expenditure suggests that the services provided by Essential Energy can be delivered much more efficiently. Across all of our assessment techniques—incorporating benchmarking, category analysis and detailed review—there is a consistent body of evidence that demonstrates Essential Energy's historical efficiency is lower than the majority of its peers in the NEM. This is consistent with the findings of the NSW Government's review,[51] Deloitte Access Economics' findings in relation to Essential Energy's labour practices, and comments made by the CEO of NNSW.[52]

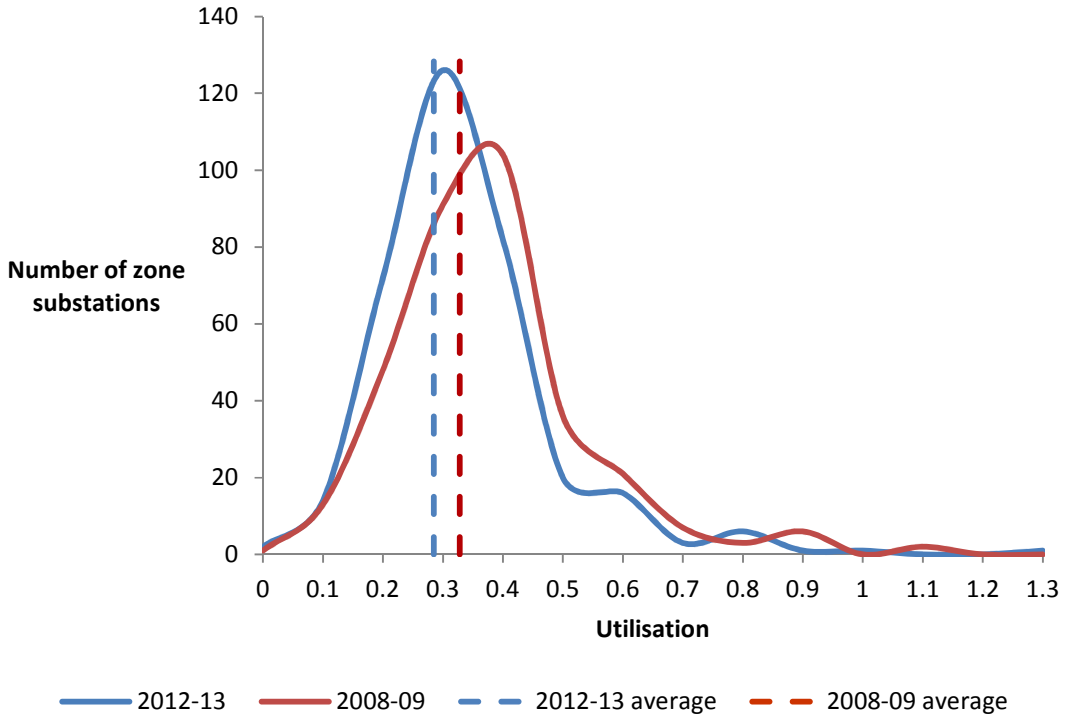
In relation to capital expenditure (capex), Essential Energy is forecasting lower expenditure over the 2014–19 period. However, this proposed reduction follows a period of unprecedented high levels of capex. A key driver of the high levels of capex during the 2009–14 regulatory control period was the change to the planning standards, combined with expected demand growth. In retrospect, the expected demand levels did not eventuate and the NSW Government amended Essential Energy's distribution licence to remove the deterministic planning standard that had been a key driver of much of the previous expenditure.

The result of this expenditure and falling demand can be seen in an analysis of the asset utilisation rates. As shown in Figure 5-1, asset utilisation (shown at the zone substation level) decreased markedly from 2008–09 to 2012–13.

[51] HoustonKemp Economists, *Electricity network service standards: An overview – a report for the NSW Department of Premier and Cabinet*, 2 September 2014.

[52] Vince Graham, Selling off electricity networks will give NSW cheaper power bills, The Australian, 20 August 2014.

Figure 5-1 Zone substation utilisation 2008–09 and 2012–13



Source: AER analysis; reset RIN.
Note: Utilisation is the ratio of maximum demand and the normal cyclic rating of each substation for the specified years.[53] Figure 5.1 shows the number of Essential's total zone substations at each utilisation band.

Putting together the evidence of past levels of opex, combined with the removal of key drivers for capex, it is to be expected that Essential Energy would submit lower forecasts for the 2014–19 period.

Efficiency of forecast expenditure

We are not satisfied that Essential Energy's regulatory proposal has sufficient regard to the levels of efficiency that it should be achieving, and see many opportunities for network services to be provided more efficiently. Our reviews across both capex and opex have highlighted systemic inefficiencies in the work practices employed by Essential Energy and the methodology used to forecast costs.

While Essential Energy acknowledges that it is currently incurring costs above efficient levels, it has (after considering reclassified services) proposed similar levels of opex to the previous period. Essential Energy is proposing that consumers bear some of the costs while it makes the necessary adjustments to become more efficient.[54] This is reflected in Essential Energy's proposal in two ways. First, the proposed revenue requirement is built on existing inefficient base levels of capex and opex. Second, Essential Energy is proposing to transition to an efficient level of opex over the forecast period.

Grid Australia has previously noted that if we reduce a NSP's allowance, it may not be realistic for the NSP to make the necessary efficiency savings immediately; rather, a Fperiod to transition to the

[53] Normal cyclic rating is the maximum peak loading based on a given daily load cycle that a substation can supply each day of its life under normal conditions resulting in a normal rate of wear.
[54] See, for example, NSW DSNPs, Submission on AER issues paper, 8 August 2014, pp. 12-16.

efficient level would be appropriate.[55] However, that approach would provide for the recovery of costs that do not reasonably reflect the opex criteria and cause consumers to fund inefficient expenditure. We will consider the issue further in view of any submissions received on this matter in response to our draft decision.

On capex, Essential Energy has proposed a substantially lower forecast for the 2014–19 period, particularly in relation to augex. However, Essential Energy is seeking to undertake a substantial program of aged asset replacement that we consider is not adequately justified. Essential Energy has a relatively young network compared to its peers and much lower asset utilisation. Essential Energy 's capital efficiency has therefore been steadily declining over time.

Reviews undertaken by our technical consultants EMCa and WorleyParsons have highlighted inefficiencies in the Essential Energy proposal. Specifically, EMCa found that when estimating replacement expenditure, Essential Energy systemically overstates its efficient costs by replacing too many assets earlier than is necessary to meet the capex objectives.[56] On augmentation expenditure, WorleyParsons found that Essential Energy's forecast was overstated as only limited consideration has been given to the impact of the changes to the licence conditions from 1 July 2014. Additionally, the application of risk based cost benefit analysis assessment techniques to projected programs of work would likely result in reductions to projected expenditure.[57]

Essential Energy's approach to managing risk

A key driver of the inefficiencies discovered in Essential Energy's forecast capex is its approach to managing risk. The capital intensive nature of distribution networks makes it prohibitively expensive to build sufficient capacity to avoid all possible interruptions. In addition, the impact of a distribution outage tends to be localised to a specific part of the network, compared with the potentially widespread impact of a generation or transmission outage. For these reasons, distribution outages should be kept at what is termed efficient levels—based on the value of reliability to the community and the willingness of customers to pay—rather than trying to eliminate every possible interruption. In some instances it will be more efficient to compensate customers after an interruption rather than build sufficient capacity to avoid the event.

In the course of our review of Essential Energy's proposal we have determined that Essential Energy's risk management practices are overly risk averse and result in higher capex forecasts than necessary. This view is supported by the independent review conducted by our consultants, EMCa. We see that Essential Energy undertakes expenditure to avoid risks even when the cost benefit is not justified. This impacts all aspects of its proposal and as a consequence its revenue requirement and prices.

Demand

As discussed above, the forecast levels of demand in the 2009–14 period did not eventuate. Recent forecasts show that the trend appears to continue downwards, at least for the next few years. This means electricity networks are under less pressure to expand the network to meet the needs of additional customers or the increased demands of existing customers.

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55 Grid Australia, *Grid Australia submission on AER draft expenditure forecast assessment guidelines*, 20 September 2013, pp. 16–17.

56 EMCa, Technical review of regulatory proposals, Review of proposed replacement capex in Essential's regulatory proposal 2014–2019, October 2014, pp, iv

57 WorleyParsons, Review of proposed augmentation capex in NSW DNSP regulatory proposals 2014 - 2019, 17 November 2014, pp. 22

We understand that Essential Energy is in the process of updating its demand forecasts. If these updated forecasts are lower than those used in the regulatory proposal, this updated information may lead to further downward revisions to expenditure forecasts in our final decision.

Financial market conditions

We estimate the returns on equity and debt for a benchmark efficient business in accordance with the allowed rate of return objective. The allowed rate of return objective in the NER is: for the overall rate of return to be commensurate with the efficient financing costs of a benchmark efficient business.

The investment environment has improved since our previous decision. Our last decision for the NSW distributors was made during the height of uncertainty surrounding the global financial crisis (GFC).[58] Since then perceptions of risk have subsided and investment risk premiums have fallen as evidenced by falling credit risk premiums.[59] The Reserve Bank of Australia has also lowered its target cash rate. As a consequence, the lower cost of debt and equity translate to lower financing costs necessary to attract efficient investment.

Using our rate of return guideline as our starting point, we have assessed a rate of return that achieves the rate of return objective and the NEO and will allow Essential Energy to fund its network investment. This is lower than the rate of return allowed in 2009 and that proposed by Essential Energy which does not reflect the prevailing investment environment.

Individually, each of these key drivers has a substantial impact on the constituent components of our decision. However, it is their cumulative impact that is particularly important. Together, they indicate a consistent picture. Essential Energy's efficient level of overall revenue during the 2014–19 period should decrease substantially, compared both to the current regulatory control period and Essential Energy's proposal. This is consistent with the overall revenue level derived from the detailed analysis in our attachments and appendices.

5.2 Consumer engagement

We acknowledge that Essential Energy has had a short amount of time to implement our consumer engagement guideline for network service providers. Essential Energy has undertaken engagement strategies. However, based on feedback from stakeholders, Essential Energy has not presented compelling evidence of how its proposal adequately incorporates the views and concerns of its customers. This manifests in a number of aspects. First, the number and breadth of submissions received that do not support Essential Energy's proposal as being in the long term interests of consumers. Second, the range of issues that are important to consumers and stakeholders raised in their submissions but not reflected in Essential Energy's regulatory proposal. For example, efficient demand management options instead of capex.[60]

Based on the submissions in response to Essential Energy's regulatory proposal and our consultation with consumers, we are not satisfied that Essential Energy's proposal adequately reflects the views of consumers. In particular, consumers have indicated that they were not offered opportunities to express preferences for service standards and costs which were backed by pricing impact

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58 Lehman Brothers filed for Chapter 11 bankruptcy protection on September 15, 2008. This is generally considered the date the GFC started. See http://dm.epiq11.com/LBH/Project.

59 See attachment 3 for further information.

60 Total Environment Centre, *Submission to the AER issues paper on the NSW electricity distribution businesses' regulatory proposals*, August 2014.

information.[61] Consumers were also concerned that Essential Energy did not disclose its intention to depart from key aspects of our rate of return guideline which was developed with extensive stakeholder consultation.[62]

[61] PIAC, *Moving to a new paradigm: submission to the AER's NSW electricity distribution network price determination*, 8 August 2014, p. 31; NSW Council of Social Services, Submission to the NSW electricity distribution network price determinations, 7 August 2014.

[62] PIAC, *Moving to a new paradigm: submission to the AER's NSW electricity distribution network price determination*, 8 August 2014, p. 32; EUAA, *Submission to NSW Electricity Distribution Revenue Proposals*, 8 August 2014, p. 6.

6 Why our decision, as a whole, is preferable

The NEL anticipates that there may be two or more possible overall decisions that will or are likely to contribute to the achievement of the NEO. In those cases, we must make the decision we are satisfied will contribute to the achievement of the NEO to the greatest degree.[63]

Under the new framework we have turned our mind to the question of what outcome would contribute to the achievement of the NEO to the greatest degree. There is no sole assessment approach that would enable us to determine this question objectively. The NEL recognises this by making our task subjective. It empowers us to determine what we are satisfied contributes to the achievement of the NEO to the greatest degree.[64] In turn, we must determine how we will satisfy ourselves of this requirement. We consider this inherently involves exercising regulatory judgement.

Consistent with Energy Ministers' views, we consider a decision will contribute to the achievement of the NEO to the greatest degree where we are satisfied that it delivers the best balance between the NEO's factors.[65] To assess this, we especially consider whether we are satisfied that:

- the overall revenue allowance is consistent with the key drivers
- the constituent components of a potential decision comply with the NER's requirements.

This is a relative assessment. Some stakeholders may consider that some potential outcomes do not contribute to the achievement of the NEO. However, we have not sought to determine that issue. Rather, we have considered which of these potential outcomes we are satisfied makes the greatest contribution to the achievement of the NEO.

We acknowledge that there are a range of alternative outcomes that might contribute to the achievement of the NEO. This is particularly the case because, for several components of our decision (e.g. equity beta or the market risk premium) we could reasonably select several point estimates from within a range. In turn, this could result in different overall revenue allowances.

We are not satisfied that it is practical or necessary to consider every possible permutation specifically. However, for the reasons in our attachments and appendices we are satisfied that the specific estimates we have selected will or are likely to contribute to the achievement of the NEO to the greatest degree. In particular, we are aware of the consequences of underinvestment for the long term interests of consumers and, therefore, have consistently selected estimates we are satisfied provide Essential Energy with a reasonable opportunity to recover at least efficient costs.[66] We are satisfied this approach results in an overall decision that contributes to the achievement of the NEO to the greatest degree.

6.1 Our draft decision

We are satisfied that our draft decision contributes to the achievement of the NEO to the greatest degree. In the 2009–14 regulatory control period, several factors combined to drive substantial increases in revenue. These included:

- financial market conditions

63 NEL, s. 16(1)(d).
64 NEL, s. 16(1)(d).
65 Hansard, SA House of Assembly, 26 September 2013 p. 7173.
66 NEL, s. 7A(2) and (6).

- expectations that peak demand would grow, driving increased capex and opex
- reliability standards.

However, as discussed in section 5, these drivers have now subsided, indicating that substantial revenue reductions are appropriate. In addition, we have identified several opportunities for Essential Energy to materially improve efficiency in how it invests in, operates and promotes use of its network. Our draft decision reflects these. It sets an overall revenue level consistent with the indications from the key drivers discussed in section 5. Additionally, it is consistent with the trend in Essential Energy's revenue over the 2004–09 regulatory control period.

We are also satisfied, for the reasons set out in our attachments and appendices, the constituent components of our draft decision comply with the NER's requirements.

In addition, we are satisfied that our process for making this draft decision would contribute to the achievement of the NEO to the greatest degree. As discussed in section 3, our decision reflects the approaches set out in our guidelines, developed with extensive stakeholder input. We are satisfied they provide a consistent and balanced framework that encourages efficiency in electricity networks for the long term interests of consumers.

When compared to Essential Energy's proposal, we are satisfied that our draft decision strikes a more appropriate balance between the efficient investment, operation and use of electricity services that contribute to the achievement of the NEO. We are satisfied the overall revenue allowance for Essential Energy provides a return sufficient to promote efficient investment, while also providing Essential Energy incentives to operate its network more efficiently. We are also satisfied that the overall revenue allowance will, to some extent, mitigate potential risks that consumers are unwilling or unable to efficiently use the network.

We acknowledge that our draft decision sets an overall revenue allowance for Essential Energy that is lower than in the 2009–14 regulatory control period and in its proposal. We consider this is appropriate, given the key drivers of efficient revenue for the 2014–19 period. It is also consistent with trends that have tended to moderate the need for investment in the electricity network sector.

6.2 Essential Energy's proposal

We are not satisfied that Essential Energy's proposal would contribute to the achievement of the NEO to the greatest degree. Essential Energy's proposal lists many of the same key drivers of efficient revenue as set out in section 5.[67] However, Essential Energy's proposed overall revenue differs substantially from what the key drivers indicate is appropriate. While the key drivers of efficient revenue indicate a revenue reduction is appropriate, Essential Energy proposed increases to overall revenue. Essential Energy seems to give relatively little weight to these key drivers.

Overall, we consider Essential Energy's proposal would result in a revenue allowance that is greater than necessary for the efficient investment in and operation and use of distribution services. In our view this would not contribute to the achievement of the NEO to the greatest degree. Also, we consider such an outcome would reduce the need and, therefore, dilute the incentive for Essential Energy to transition to an economically efficient cost base.[68]

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[67] Essential Energy, *Regulatory proposal*, 30 May 2014.
[68] NEL, s. 7A(3).

6.3 Consumers' preferences

By their nature, consumer submissions do not provide a comprehensive proposal. However, submissions to the AER from the CCP and other stakeholders also suggest a need for substantial revenue reductions, consistent with indications from the key drivers of efficient revenue we discussed in section 5.

7 Total revenue requirement and impact on annual electricity bills

The total revenue requirement represents our forecast of the efficient costs a prudent operator would incur in providing distribution network services for the 2015–19 regulatory control period.

7.1 Draft decision

Our draft decision on Essential Energy's total revenue requirement over the 2015–19 (and excluding the 2014–15 transitional year) is $3678.6 million ($ nominal).[69] Our draft decision is $1888.3 million (or 33.9 per cent) less than Essential Energy's regulatory proposal.

Table 7–1 shows our draft decision on Essential Energy's building block costs and the resulting revenues (both smoothed and unsmoothed). Attachments to our draft decision discuss in detail each building block cost and its elements; our approaches to assessment; and the interrelationships between elements and across years. All these considerations are brought together to support our overall revenue allowance summarised here.

Table 7–1 AER's draft decision on Essential Energy's proposed revenues ($ million, nominal)

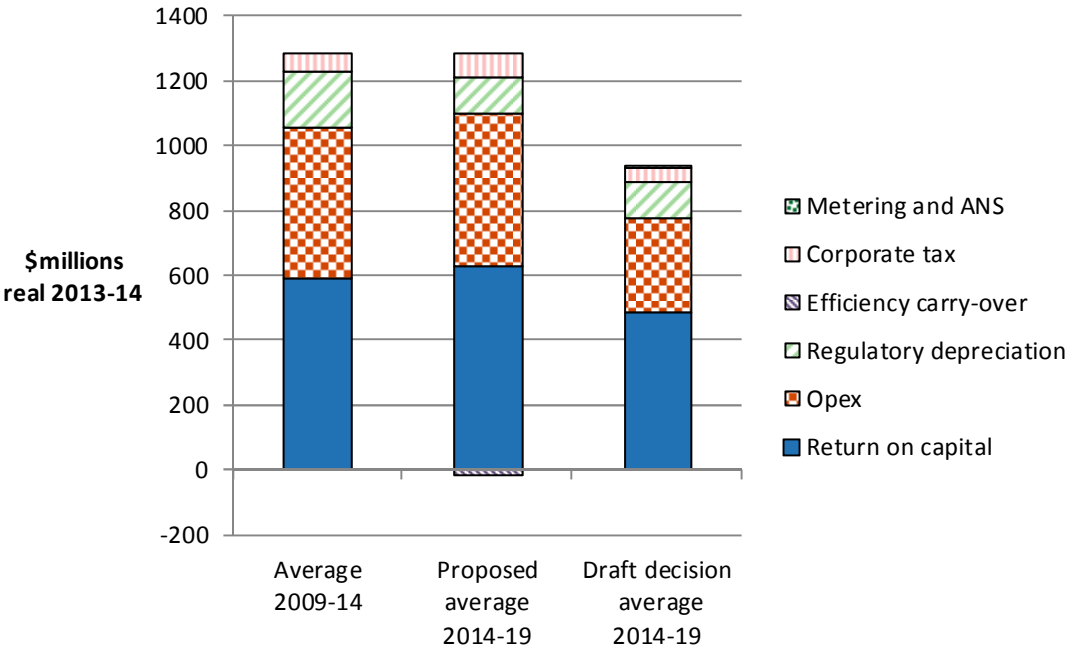
	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Return on capital	477.7	502.0	522.6	542.8	562.1	2607.2
Regulatory depreciation[a]	98.6	116.6	132.0	136.1	129.8	613.2
Operating expenditure	288.3	298.4	309.6	321.7	334.1	1552.1
Efficiency benefit sharing scheme (carryover amounts)	0.0	0.0	0.0	0.0	0.0	0.0
Corporate tax allowance	40.1	38.1	47.1	46.7	46.0	217.9
Meters, ANS & ERW net costs[b]	48.1	n/a	n/a	n/a	n/a	48.1
Annual revenue requirement (unsmoothed)	952.9	955.1	1011.3	1047.2	1072.0	5038.5
Annual expected revenue (smoothed)	**1291.7**	**885.9**	**908.0**	**930.7**	**954.0**	**4970.3**
X factor (%)	n/a[c]	33.09%	0.00%	0.00%	0.00%	n/a

Source: AER analysis.
(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening RAB.
(b) These are the efficient net costs of metering, ancillary network services and emergency recoverable works as determined by the AER. They reflect the difference between the costs and any offsetting revenues recovered by the service provider through separate charges.
(c) In our transitional decision, we determined the placeholder revenue for 2014–15. In this draft decision to update the 2014–15 revenue for our assessment of efficient costs we determined X factors for the final four years of the 2014–19 period. This is to adjust Essential Energy's total revenue requirement for the 2015–19 regulatory control period for the difference between the placeholder revenue and our decision on Essential Energy's efficient costs for 2014–15.

[69] This amount excludes the MAR for the transitional 2014–15 year.

Figure 7-1 compares (on average) our draft decision on Essential Energy's building block costs against what was proposed by Essential Energy for the 2014–19 period and what were approved for the 2009–14 regulatory control period.

Figure 7-1 AER's draft decision and Essential Energy's proposed annual building block costs ($ million, 2013–14)

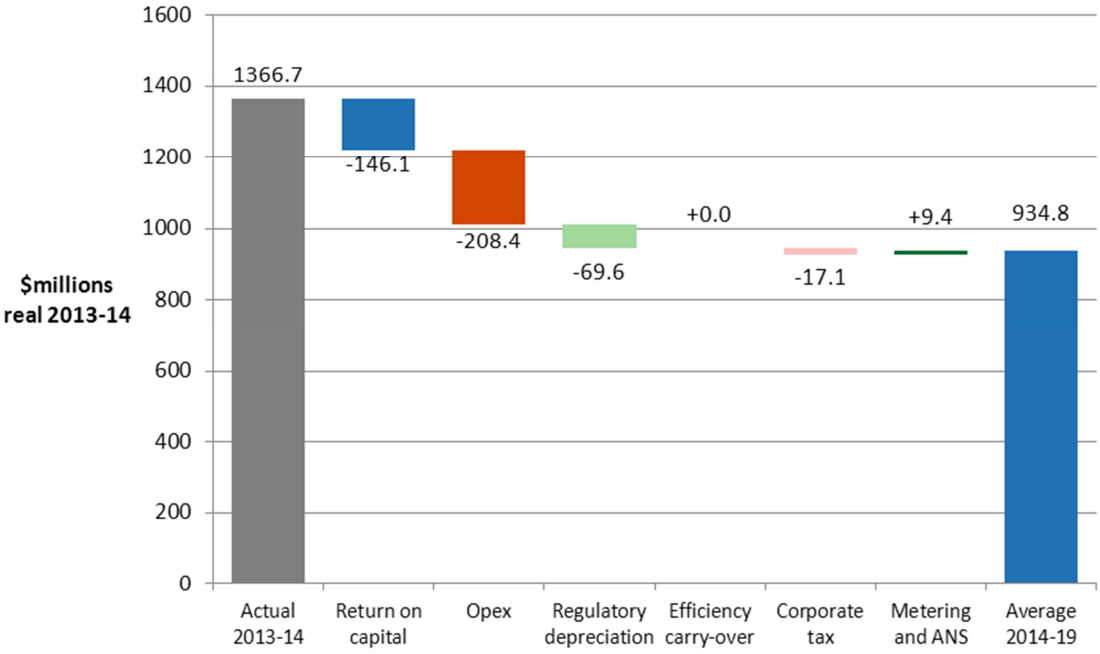


Source: AER analysis.

Figure 7-2 shows the size of the changes in the building block costs from our draft decision and how these impact on revenues on average. The estimated actual revenue for 2013–14 is used as a base from which the impact of the changes can be shown. For example, the most significant change is to the opex allowance that reduces the annual revenue requirement on average by about $208.4 million.[70]

[70] The meters and ANS net costs are only recoverable from standard control services for 2014–15 consistent with the transitional rules. The actual revenue for 2013–14 also includes the net costs for metering and ANS.

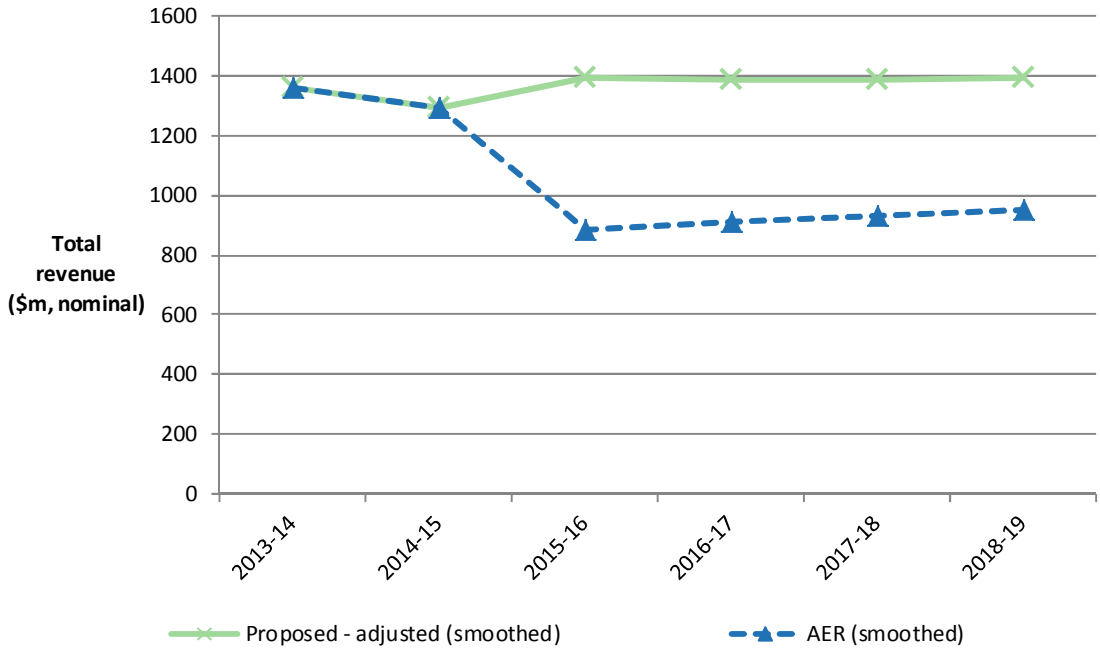
Figure 7-2 AER's draft decision on building block costs ($ million, 2013–14)



Source: AER analysis.
Notes: 'Actual 2013–14' is Essential Energy's latest estimate of actual revenue to be recovered for that year. In order to calculate building block changes, this estimate is notionally divided in the same proportion as allowed building block revenue over the 2009–14 regulatory control period.

Figure 7-3 compares our draft decision on Essential Energy's expected revenues with Essential Energy's proposal (adjusted to reflect the transitional placeholder decision) for the 2014–19 period. In this figure, the two lines both start from the transitional placeholder decision for 2014–15. This placeholder revenue was used as the basis from which prices for 2014–15 were determined. Because Essential Energy' did not account for the placeholder decision in its proposal, there would be an increase in revenues between 2014–15 and 2015–16 to get back to Essential Energy's proposed trend.

Figure 7-3 AER's draft decision on expected revenues compared with Essential Energy's proposed (adjusted) revenues for 2014–19 ($ million, nominal)



Source: AER analysis.

The smoothing we conducted to determine the expected revenues for each year also achieves the NER requirement for a true-up in relation to the transitional year of 2014–15. The placeholder revenue from the transitional decision for 2014–15 is used as a base from which the smoothing occurs. This means the expected revenue for 2014–15 matches what was targeted for pricing purposes for that year. The smoothing process requires us to equate the smoothed and unsmoothed revenues over the entire 2014–19 period in net present value terms. Any difference between the annual revenue requirement for 2014–15 now determined by us in this decision and the placeholder amount is trued-up through this smoothing process.[71] The difference is being effectively spread over the remaining four years of the 2014–19 period. Attachment 1 explains the smoothing process further.

7.2 Indicative impact of distribution charges on electricity bills in Essential Energy's distribution area

Our draft decision on Essential Energy's expected revenues ultimately affects the annual electricity bills paid by customers. Essential Energy's distribution network is regulated under a revenue cap, so in addition to our decision on expected revenues, changes in the consumption of electricity will also affect the prices ultimately charged to consumers.

Distribution charges are just one component of the customer's total annual electricity bill (which also includes transmission, wholesale and retail costs). The distribution network charge represents approximately 43 per cent of the average annual electricity bill for customers on Essential Energy's network.[72]

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[71] This true-up covers both standard and alternative control services as required under the transitional rules.

[72] See IPART, *Final report: Review of regulated retail prices for Electricity from 1 July 2013 to 30 June 2016*, June 2013, p. 5.

We estimate the effect of our draft distribution determination on the average annual electricity bills for residential and small business customers as follows. Essential Energy included a breakdown of distribution charges in its regulatory proposal, which includes demand and price information for each type of distribution charge. This breakdown allows the calculation of the weighted average change in distribution charges each year. We adjust this weighted average for changes in total distribution revenue between Essential Energy's proposal and our draft decision.[73] We assume other components of the electricity bill (for example transmission, wholesale and retail energy costs) are held constant.

Table 7–2shows the estimated impact of our draft decision over the 2014–19 period compared with Essential Energy's proposal on the average residential and small business customers' annual electricity bills in Essential Energy's network area.

Table 7–2 AER's estimated impact of the draft decision on the average residential and small business customers' electricity bills in Essential Energy's network for the 2014–19 period ($ nominal)

	2013–14	2014–15	2015–16	2016–17	2017–18	2018–19
Essential Energy proposal						
Residential annual bill[a]	2703	2658	2754	2762	2771	2779
Annual change		–45 (–1.6%)	95 (3.6%)	8 (0.3%)	9 (0.3%)	9 (0.3%)
Small estimated annual bill[b]	4567	4492	4652	4667	4681	4696
Annual change		–75 (–1.6%)	161 (3.6%)	14 (0.3%)	14 (0.3%)	14 (0.3%)
AER draft decision						
Residential annual bill[a]	2703	2658	2313	2340	2366	2387
Annual change		–45 (–1.6%)	–346 (–13%)	27 (1.2%)	26 (1.1%)	21 (0.9%)
Small business annual bill[b]	4567	4492	3908	3954	3998	4033
Annual change		–75 (–1.6%)	–584 (–13%)	46 (1.2%)	44 (1.1%)	35 (0.9%)

Source: AER analysis; AER, Energy Made Easy; IPART, *Final report: Review of regulated retail prices for electricity - from 1 July 2013 to 30 June 2016*, June 2013, p. 5.

(a) Based on the annual charge for typical consumption of 6500 kWh per year during the period 1 July 2013 to 30 June 2014. The charges reflect regulated price only. Sample postcode: 2650.

(b) Based on the annual charge sourced from Energy Made Easy for a typical consumption of 10000 kWh per year during the period 1 July 2013 to 30 June 2014. The charges reflect regulated price only. Sample postcode: 2650.

Attachment 1 includes more information on the derivation of indicative bill impacts.

[73] This means that, for the purpose of estimating indicative distribution charges, we have adopted the same demand breakdown as Essential Energy's proposal. We discuss our draft decision on Essential Energy's demand in attachment 6.

8 Key elements of the building blocks

There is no one tool that by itself can determine an overall revenue allowance. Therefore in setting our alternative overall revenue allowances for Essential Energy of $3678.6 million ($ nominal) for the 2015–19 regulatory control period we:

- apply relevant tests under the NER, the assessment methods and tools developed as part of our Better Regulation guidelines and consider information provided by Essential Energy, the CCP, consultants and stakeholder submissions.
- consider our total revenue allowance against section 16 of the NEL, including the constituent decisions and the interrelationships we discussed in section 5.

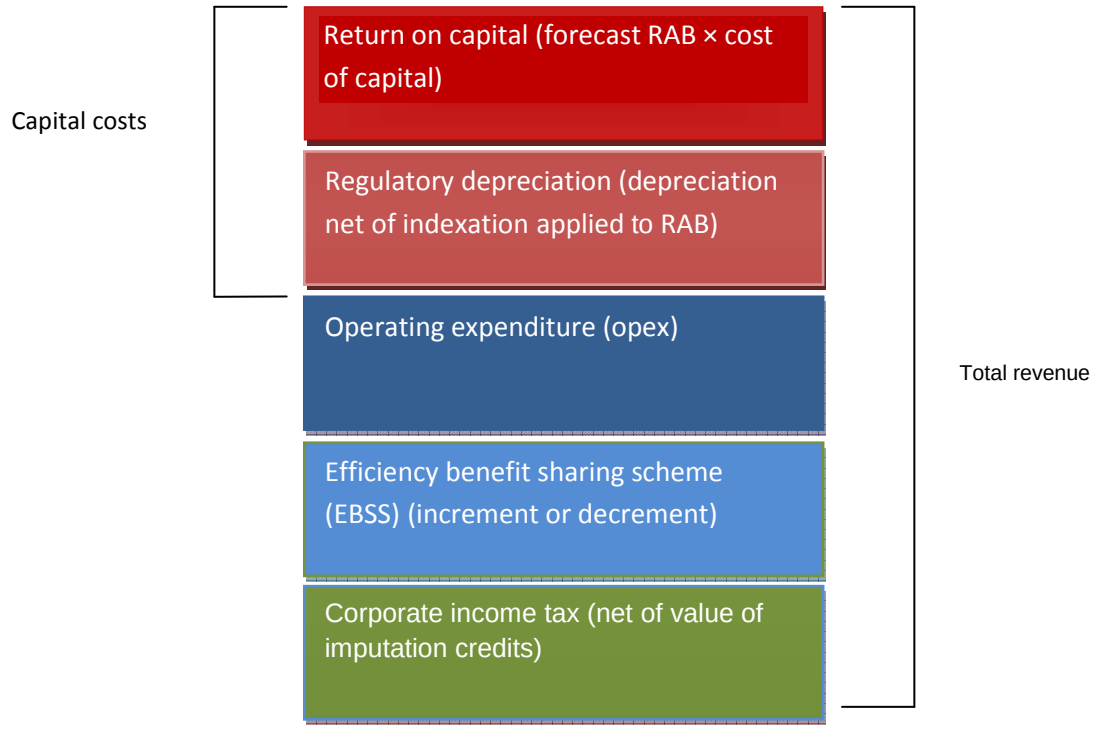
8.1 The building block approach

We have employed the building block approach to determine Essential Energy's annual revenue requirement—that is, we based the annual revenue requirements on our estimated efficient costs that Essential Energy is likely to incur in providing distribution network services. The building block costs include:[74]

- a return on the Regulatory Asset Base (RAB) (return on capital)
- depreciation of the RAB (return of capital)
- forecast opex
- increments or decrements resulting from incentive schemes such as the efficiency benefit sharing scheme (EBSS)
- the estimated cost of corporate income tax.

Our assessment of capex directly affects the size of the RAB and therefore, the revenue generated from the return on capital and return of capital building blocks.

Figure 8-1 The building block approach for determining total revenue



The following section summarises our decision by building block and provides our high level reasons and analysis.

8.2 Regulatory asset base

The RAB is the value of Essential Energy's assets that are used to provide distribution network services. These assets include distribution poles and wires, substations, IT systems, land and easement, motor vehicles and buildings. The RAB is the value on which Essential Energy earns a return on capital. Further, Essential Energy earns a depreciation allowance (or a return of capital) on assets in its RAB. So, the RAB is an important input to the return on capital and depreciation building blocks, and thus to the revenue requirement.

As part of this draft decision, we are required to assess Essential Energy's proposed opening value for the RAB for each year of the 2014–19 period.[75] Our assessment involved:

- rolling forward the opening RAB at 1 July 2009 to determine the closing RAB as at 30 June 2014
- using our draft decision on forecasts of depreciation, capex, disposals and inflation for the 2014–19 period to roll forward Essential Energy's forecast RAB for each year of that period.

Attachment 2 sets out the detailed reasons for our draft decision on Essential Energy's RAB.

8.2.1 Draft decision

Our draft decision is to set Essential Energy's opening RAB at $6685.4 million at 1 July 2014.

[75] NER, cl. 6.5.1 and S6.2.

We determine that the forecast depreciation approach is to be used to establish the opening RAB at the commencement of the 2019–24 regulatory control period for Essential Energy.

Table 8–1 set out our draft decisions on the roll forward of Essential Energy's RAB during the 2009–14 regulatory control period and the forecast RAB for the 2014–19 period respectively.

Table 8–1 AER's draft decision on Essential Energy's RAB for 2009–14 ($ million, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14[a]
Opening RAB	4319.4	4812.7	5361.5	6012.4	6461.0
Capital expenditure[b]	680.4	709.4	740.6	650.6	578.7
Inflation indexation on opening RAB	78.6	136.9	181.7	106.0	158.3
Less: straight-line depreciation	265.8	297.5	271.4	308.0	332.5
Closing RAB	4812.7	5361.5	6012.4	6461.0	6865.4
Difference between estimated and actual capex (1 July 2008 to 30 June 2009					–40.3
Return on difference for 2008–09 capex					–24.6
Closing RAB as at 30 June 2014					6800.5
Meters moved to alternative control services					–115.1
Opening RAB as at 1 July 2014					6685.4

Source: AER analysis.
(a): Based on estimated capex. We will update the RAB roll forward for actual capex at the time of the final decision.
(b): As incurred, net of disposals and capital contributions, and adjusted for actual CPI.

Table 8–2 sets out our draft decision on the roll forward of Essential Energy's forecast RAB for the 2014–19 period.

Table 8–2 AER's draft decision on Essential Energy's RAB for the 2014–19 period ($ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19
Opening RAB	6685.4	7024.5	7313.1	7595.8	7866.3
Capital expenditure[a]	437.7	405.2	414.8	406.5	408.6
Inflation indexation on opening RAB	167.1	175.6	182.8	189.9	196.7
Less: straight-line depreciation	265.7	292.2	314.9	326.0	326.5
Closing RAB	7024.5	7313.1	7595.8	7866.3	8145.0

Source: AER analysis.
(a): Net of forecast disposals and capital contributions.

8.2.2 Summary of analysis and reasons

We do not accept Essential Energy's proposed opening RAB of $6770.3 million ($ nominal) as at 1 July 2014. Instead, we determine an opening RAB value of $6685.4 million ($ nominal) as at 1 July 2014. This is because we amended Essential Energy's proposed actual capex values to reverse the

movements in capitalised provisions from 2009–2014. This amendment reduced the proposed opening RAB as at 1 July 2014 by $84.9 million (or 1.3 per cent) compared to that proposed.

We forecast Essential Energy's closing RAB will be $8145.0 million at 30 June 2019, which represents a 9.6 per cent reduction on Essential Energy's proposed amount. The main reasons for this reduction are our adjustments to:

- forecast capex (attachment 6)
- the opening RAB at 1 July 2014 (attachment 2)
- forecast depreciation (attachment 5).

Details of our approach in deriving the value of the RAB and relevant interrelationships are set out in attachment 2.

8.3 Rate of return (return on capital)

The allowed rate of return provides a network service provider (NSP) a return on capital to service the interest on its loans and give a return on equity to investors. The return on capital building block is calculated as a product of the rate of return and the value of the RAB.[76]

8.3.1 Draft decision

We are satisfied that the allowed rate of return of 7.15 per cent (nominal vanilla[77]) we determined, subject to updating, achieves the allowed rate of return objective.[78] We are not satisfied that Essential Energy's proposed (indicative) 8.83 per cent return is such that it achieves the allowed rate of return objective. The allowed rate of return of 7.15 per cent will be updated annually. This is because our draft decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.[79] Our draft decision is set out in Table 8–3.

Table 8–3 Table 5 AER's draft decision on Essential Energy's rate of return (nominal)

	2009–14 AER decision	2015–19 Essential Energy proposal	2015–19 AER draft decision
Nominal risk free rate (cost of equity)	5.82%	4.78%[(a)]	3.55%[(b)]
Equity risk premium	6.0%	5.33%	4.55%
MRP	6.0%	6.5%	6.5%
Equity beta	1.0	0.82	0.7
Gearing ratio	60.0%	60.0%	60.0%
Inflation forecast	2.47%	2.50%	2.50%
Nominal post–tax return on equity	11.82%	10.11%	8.1%
Nominal pre–tax return on debt	8.82%	7.98%	6.51%[(c)]

[76] NER, cl.6.5.2(a).
[77] The nominal vanilla WACC combines a post-tax return on equity and a pre-tax return on debt, for consistency with other building blocks.
[78] NER, cl.6.5.2(b).
[79] NER, cl.6.5.2(i)(2).

Nominal vanilla WACC	10.02%	8.83%	7.15%

Source: AER analysis; Essential Energy, *Regulatory proposal*, May 2014; AER, *Statement of updates for the NSW distribution network service providers' distribution determination*, November 2009.

(a) Essential Energy proposed a risk free rate based on a long term averaging period (1883–2011), which does not require updating for the final decision. See: Essential Energy, *Regulatory proposal,* May 2014, p. 106.

(b) This is a prevailing indicative risk free rate based on a 20 business day averaging period from 17 September to 15 October 2014. The risk free rate is to be updated for the final decision.

(c) This return on debt estimate, subject to our final decision, will be used to update the revenues we previously determined for the 2014–15 (transitional) regulatory year.

8.3.2 Summary of analysis and reasons

Our approach

We consider that our approach, which includes a process that lends itself to capturing a broad range of material from all stakeholders while founded on the rate of return framework, would result in an estimate of the rate of return that contributes to achieving the allowed rate of return objective. Our approach is based on the rate of return framework in the NER. Under this framework, our key task is to determine an overall rate of return that we are satisfied achieves the allowed rate of return objective.[80] An important feature of the rate of return framework is the recognition that there is no one correct answer that achieves the allowed rate of return objective.[81]

In December 2013, we published the Rate of Return Guideline (the Guideline).[82] The Guideline was designed through extensive consultation and included effective and inclusive consumer participation.[83] We agree with stakeholders that certainty and predictability of outcomes in rate of return issues could materially benefit the long term interest of consumers.[84]

Return on equity

Our return on equity estimate is determined by applying an iterative six step process as set out in the Guideline (foundation model approach). We have had regard to a large amount of relevant information, including other equity models. At different stages of our six step iterative process we have used this material to inform the return on equity estimate that contributes to the allowed rate of return objective.

The evidence indicates that the Sharpe–Lintner capital asset pricing model (SLCAPM) is the superior model in terms of estimating expected equity returns. We have therefore adopted this model as our foundation model. We commissioned expert reports from Professor Michael McKenzie and Associate professor Graham Partington (McKenzie & Partington), and Associate professor John Handley. Both confirm that employing our foundation model approach and using the SLCAPM as the foundation

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80 NER, cl.6.5.2(b).

81 AEMC, *Rule determination: National electricity amendment (Economic regulation of network service providers) Rule 2012: National gas amendment (Price and revenue regulation of gas services) Rule 2012*, 29 November 2012, p. 67 (AEMC, *Final rule change determination*, November 2012); AEMC, *Final rule change determination*, November 2012, p. iv, AEMC, *Final rule change determination*, November 2012, p. 38; The High Court of NZ stated: "In determining WACC, precision is therefore an elusive and perhaps non-existent quality. Setting WACC is, we suggest, more of an art than a science. The use of WACC, in conjunction with RAB values, to set prices and revenue in price-quality regulation gives significance to WACC estimates that may not exist outside this context." *Wellington International Airport Ltd & Others v Commerce Commission* [2013] NZHC 3289, para. 1189.

82 NER, cl.6.5.2(m).

83 http://www.aer.gov.au/node/18859

84 ENA, *Response to the Draft Rate of Return Guideline of the AER*, 11 October 2013, p.1, AER, *Better regulation: Explanatory statement rate of return Guideline, Appendices*, December 2013, Appendix I, Table I.4, pp.185–186.

model, in the context of the vanilla WACC formula is expected to lead to a rate of return that meets the allowed rate of return objective.[85]

Our foundation model (SLCAPM) input parameters (MRP and equity beta) are determined after considering a range of relevant material and determining a point estimate that is most suited for our task. We evaluated our SLCAPM point estimate against other information. The critical allowance for an equity investor in a benchmark efficient entity is the allowed equity risk premium (ERP) over and above the estimated risk free rate at a given time.[86] Our estimate of the ERP for the benchmark efficient entity is 4.55 per cent. Under the application of the standard SLCAPM, this equals the MRP multiplied by the equity beta. Hence, we have compared ERP estimates where relevant, as presented in Figure 8–2. We find that our ERP estimate is within the range of other information available to inform the return on equity. Our analysis shows that:

- The Wright approach to specifying the CAPM results in an ERP range of 2.6 to 6.5 per cent. This equates to a return on equity range of 6.2 to 10.1 per cent with a prevailing risk free rate.
- ERP estimates from other market participants (independent valuers, brokers, and other regulators) for comparable firms range from 3.3 to 6.2 per cent. This equates to a return on equity range of 6.9 to 9.8 per cent with the prevailing risk free rate.
- Our SLCAPM return on equity estimate is about 2.5 percentage points above the prevailing return on debt. This reflects the difference between our ERP of 4.55 per cent and the debt risk premium (DRP) on 10 year BBB bonds of approximately 2.08 per cent.[87]

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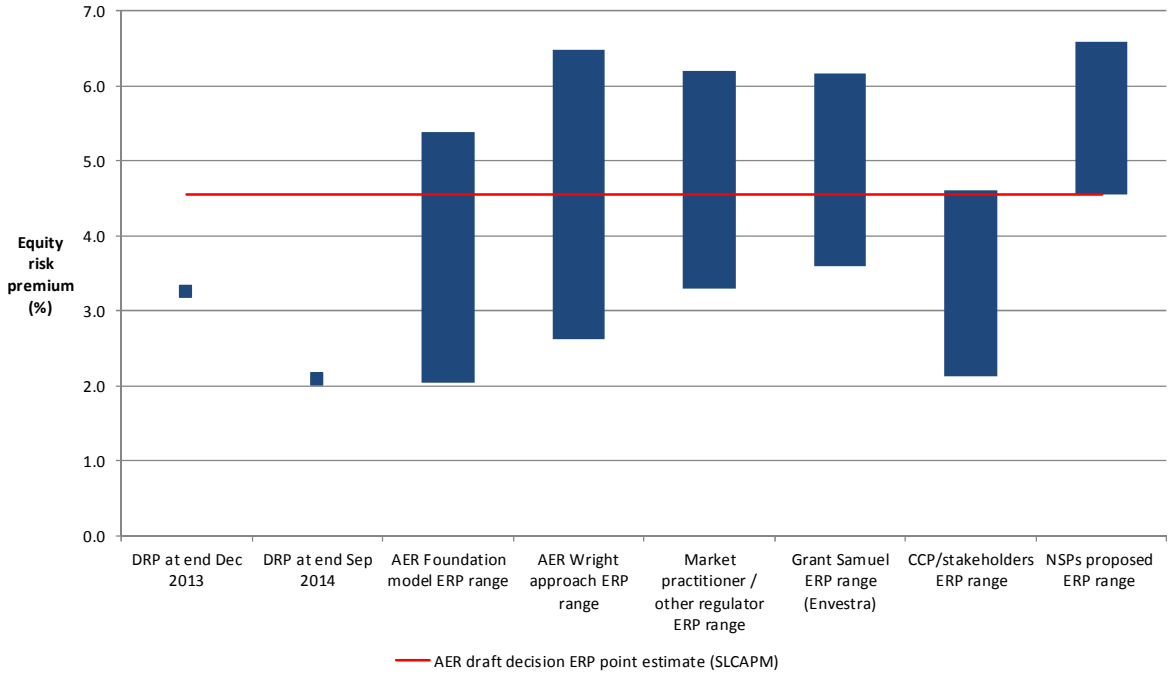
85 McKenzie & Partington, *Part A: Return on equity, Report to the AER*, October 2014, p.13; John Handley, *Advice on return on equity, Report prepared for the AER*, October 2014, p.3.

86 Our task is to determine the efficient financing costs commensurate with the risk of providing regulated network service by an efficient benchmark entity (allowed rate of return objective). Risks in this context are those which are compensated via the return on equity (systematic risks).

87 To calculate this, we use the RBA's published yields on 10 year BBB non-financial corporate bonds, specifically, the spread to CGS yields (as at 30 September). These are not reflective of our draft decision return on debt estimate which is calculated as an average of the RBA and Bloomberg (BVAL) data series. We have also made an extrapolation adjustment to the RBA data series.

Figure 8–2 Other information comparisons with the AER allowed ERP



Source: AER analysis and various submissions and reports
Notes: A detailed explanation of this figure can be found in attachment 3: Rate of return.

Return on debt

Our return on debt estimate is derived by using the trailing average approach. This is a change from our approach for the current period which was to apply an on-the-day approach. Our return on debt estimate incorporates a transition from the current on-the-day approach to the new trailing average approach.

We assessed the trailing average approach relative to the other approaches a regulator can apply to estimate the return on debt under the rules.[88] We conclude that on balance, the trailing average approach is preferable because it may better contribute to the achievement of the allowed rate of return objective.[89] We are satisfied that a benchmark efficient entity would hold a staggered portfolio of long term (10 year) debt. By this we mean that 10 per cent of the debt is new or refinanced each year. This means that for the 2014–2019 period, the benchmark efficient entity will be issuing new debt or refinancing existing debt each year. It also means that at the start of that period, the benchmark efficient entity will have in place a portfolio of debt that is existing debt and was issued in the past. We consider it is reasonable to update 10 per cent of the benchmark efficient entity's return on debt annually going forward. Our application of the trailing average approach is based on a simple average approach that provides for 10 per cent of the benchmark efficient entity's debt portfolio to be refinanced/issued each regulatory year.

There is agreement between service providers (regulatory proposals currently before us) and us on the use of the trailing average approach and that and efficient benchmark entity would hold a staggered portfolio of long term (10 year) debt. However, there is no agreement on how we should move from the current approach to the trailing average.

88 NER, cl.6.5.2(j).
89 NER, cl.6.5.2(h).

We are satisfied that it is reasonable to commence the trailing average with an initial estimation of the return on debt that is then progressively updated over the period of the trailing average. For new debt that is progressively issued in the 2014–19 period and beyond, we apply the trailing average approach immediately. For existing debt that was issued before the commencement of the 2014–19 period, we continue to apply the on-the-day approach until that debt is refinanced. We update the debt portfolio by 10 per cent each year, consistent with a staggered debt portfolio with a benchmark debt term of 10 years. After 10 years, the entire debt portfolio has been updated and incorporated into the trailing average approach, and the transition is complete. This approach is the same as the transitional arrangements we proposed in the rate of return guideline. Our transitional arrangements:

- minimise the potential mismatch between the allowed return on debt and the actual return on debt of the benchmark efficient entity as it transitions its financing practices, and
- avoid potential windfall gains or losses to service providers or consumers from changing the regulatory regime for the return on debt.

We adopt a 10 year term for the return on debt with a BBB+ credit rating. Whilst all service providers with current regulatory proposals agree with us on the term, Ausgrid, Endeavour Energy, Essential Energy, ActewAGL and JGN proposed a BBB credit rating.[90] We are satisfied that our benchmark efficient entity operating within Australia in gas, electricity, distribution or transmission networks face similar degrees of risk, including similar credit risks. Accordingly, we are satisfied that one benchmark credit rating should apply in our decisions for each of these sectors. Adopting a single credit rating is consistent with our adoption of a single definition of the benchmark efficient entity.

We use the debt yields from a third party data provider for estimating the return on debt. All service providers with current regulatory proposals have proposed to use a third party dataset for estimating the return on debt. We reviewed the data from Bloomberg (BVAL curve) and the RBA to be satisfied on the data that is most likely to reflect the efficient financing costs of a benchmark efficient entity at this time. We find that neither the RBA curve nor the BVAL curve is directly implementable in its published form for our purposes. However, we consider that both curves can be implemented: in a way that will be sufficiently robust, fit for purpose and replicable, and through the automatic application of a formula, as required by the NER.[91] We are satisfied that an average of the two data series will contribute to achieving the allowed rate of return objective.

8.4 Value of imputation credits (gamma)

Under the Australian imputation tax system, investors can receive an imputation credit for income tax paid at the company level.[92] For eligible investors, this credit offsets their Australian income tax liabilities. If the amount of imputation credits received exceeds an investor's tax liability, that investor can receive a cash refund for the balance. Imputation credits are therefore a benefit to investors in addition to any cash dividend or capital gains they receive from owning shares.

In determining a service provider's revenue allowance, the rules require that the estimated cost of corporate income tax be estimated in accordance with a formula that reduces the estimated cost by the 'value of imputation credits'.[93] That is, the revenue allowance granted to a service provider to

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90 Ausgrid, *Regulatory proposal*, May 2014, pp. 70–71; Endeavour Energy, *Regulatory proposal*, May 2014, pp. 104–105, Essential Energy, *Regulatory proposal*, May 2014, pp. 90–92; ActewAGL, *Regulatory proposal*, 2 June 2014 (resubmitted 10 July 2014), p. 255; JGN, *Access arrangement information*, 30 June 2014, p. 9.

91 NER cl. 6.5.2(l).

92 *Income Tax Assessment Act 1997*, parts 3–6.

93 NER, cl 6.4.3(a)(4), 6.4.3(b)(4), 6.5.3, 6A.5.4(a)(4), 6A.5.4(b)(4) and 6A.6.4; NGR, rr. 76(c) and 87A.

cover its expected tax liability must be reduced in a manner consistent with the value of imputation credits.

8.4.1 Draft decision

We do not accept Essential Energy's proposed value of imputation credits of 0.25. Instead, we adopt a value of imputation credits of 0.4.

The value we adopt is lower than the value of 0.5 proposed in the rate of return guideline. Although we have broadly maintained the approach to determining the value of imputation credits set out in the guideline, we have re-examined the relevant evidence and estimates. This re-examination, and new evidence and advice considered since the guideline, led us to depart from the value in the guideline.

8.4.2 Summary of analysis and reasons

Estimating the value of imputation credits is a complex and imprecise task. There is no consensus among experts on the appropriate value or estimation techniques to use.

Consistent with the relevant academic literature, we estimate the value of imputation credits as the product of the distribution rate and the utilisation rate. While there is a widely accepted approach to estimating the distribution rate, there is no single accepted approach to estimating the utilisation rate and there is a range of evidence relevant to the utilisation rate. This includes:

- The proportion of Australian equity held by domestic investors (the 'equity ownership approach')—this approach reflects that domestic investors are typically able to use imputation credits to reduce their tax liability or redeem for cash, whereas foreign investors cannot.
- The reported value of credits utilised by investors in Australian Taxation Office (ATO) statistics ('tax statistics')—this approach reflects that the ATO maintains records of the amount of imputation credits claimed by investors in their tax returns.
- Implied market value studies—while there is no separate market in which imputation credits are traded, and therefore there is no observable market price for imputation credits, this approach reflects that the value of imputation credits can be inferred from the change in market prices of financial instruments which trade with and without imputation credits attached.

In estimating the utilisation rate, we place:

- significant reliance upon the equity ownership approach
- some reliance upon tax statistics, and
- less reliance upon implied market value studies.

The relative importance that we assign to each approach is supported by advice received from Associate Professor John Handley of the University of Melbourne and Associate Professor Martin Lally of Victoria University of Wellington.[94]

[94] J. Handley, *Report prepared for the Australian Energy Regulator: Advice on the value of imputation credits*, 29 September 2014; M. Lally, *The estimation of gamma*, 23 November 2013, p. 4.

Overall, the evidence on the distribution rate and the utilisation rate suggests that a reasonable estimate of the value of imputation credits is within the range 0.3 to 0.5. From within this range, we choose a value of 0.4. This is because:

- The balance of evidence from the equity ownership approach, on which we have placed the most reliance, suggests a value between 0.4 and 0.5.
- The evidence from tax statistics suggests the value could be lower than 0.4. Therefore we choose a value at the lower end of the range suggested by the balance of evidence from the equity ownership approach (that is, 0.4).
- A value of 0.4 is also reasonable in light of the evidence from implied market value studies and the lesser degree of reliance we place upon these studies.

In determining the value of imputation credits, we have considered the wide range of evidence before us with regard to its merits. We consider that a value of imputation credits of 0.4 is reasonable because:

- It is within the range of values indicated by the evidence, and the relevance of the evidence is supported by expert opinion.
- It primarily reflects an estimate of the utilisation rate from the equity ownership approach. Handley considered this the most important approach to estimating the utilisation rate, relative to the alternatives of tax statistics and implied market value studies.[95] The equity ownership approach was Lally's second preference after his recommendation for a utilisation rate of 1.[96]
- It is within the 'preferred' range for the value of imputation credits in Handley's recent advice.[97]
- Based on the evidence before us at this time, adopting a value of imputation credits that is rounded to one decimal place appropriately reflects the uncertainty and imprecision associated with this parameter. This uncertainty is evident in the range of views and values that have been espoused by experts. The imprecision of determining the value of imputation credits was emphasised by Handley.[98]

8.5 Regulatory depreciation (return of capital)

We use regulatory depreciation to model the nominal asset values over the 2014–19 period and set the depreciation allowance as part of the overall revenue allowance for Essential Energy. The regulatory depreciation allowance is the net total of the straight-line depreciation (negative) amount and the (positive) amount from indexation of the RAB.

We have to decide on whether to approve the depreciation schedules submitted by Essential Energy setting out its proposed allowance. If we decide against approving Essential Energy's depreciation

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95 J. Handley, *Report prepared for the Australian Energy Regulator: Advice on the value of imputation credits*, 29 September 2014, p.31.

96 M. Lally, *The estimation of gamma*, 23 November 2013, p. 4. Lally's recommendation of a utilisation rate of 1 is based on his consideration that, because we use a domestic rate of return framework, we should assume that all investors in the market are domestic (and therefore eligible to make full use of imputation credits).

97 J. Handley, *Report prepared for the Australian Energy Regulator: Advice on the value of imputation credits*, 29 September 2014, p.3.

98 J. Handley, *Report prepared for the Australian Energy Regulator: Advice on the value of imputation credits*, 29 September 2014, p.32.

schedules we must determine depreciation schedules to apply to Essential Energy as set out in the NER.[99]

Attachment 5 sets out our detailed reasons for our draft decision on Essential Energy's regulatory depreciation allowance and depreciation schedules.

8.5.1 Draft decision

Our draft decision is to determine alternative depreciation schedules, and hence, the depreciation allowance, to apply to Essential Energy.[100] Table 8–4 sets out our draft decision on Essential Energy's depreciation allowance for the 2014–19 period. Our draft decision sets the allowance at $613.2 million ($ nominal), or 0.2 per cent, less than the allowance Essential Energy proposed.

Table 8–4 AER's draft decision on Essential Energy's depreciation allowance for the 2014–19 period

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Straight-line depreciation	265.7	292.2	314.9	326.0	326.5	1 525.3
Less: inflation indexation on opening RAB	167.1	175.6	182.8	189.9	196.7	912.1
Regulatory depreciation	98.6	116.6	132.0	136.1	129.8	613.2

Source: AER analysis.

8.5.2 Summary of analysis and reasons

We do not accept Essential Energy's proposed regulatory depreciation allowance of $612.1 million ($ nominal) for the 2014–19 period. Instead, we determine a regulatory depreciation allowance of $613.2 million ($ nominal) for Essential Energy. In coming to this decision, we:

- Accept Essential Energy's proposed asset classes, straight-line method, and the majority of standard asset lives used to calculate the regulatory depreciation allowance. We consider that Essential Energy's proposed asset classes and standard asset lives are generally consistent with those approved at the 2009–14 distribution determination and reflect the nature and economic lives of the assets.[101]
- Accept Essential Energy's proposed weighted average method to calculate the remaining asset lives as at 1 July 2014. However, we have updated these remaining asset lives to reflect our adjustments to the RAB in the roll forward model (RFM), as discussed in attachment 2.
- Removed the asset classes of 'Emergency spares (major plant, excludes inventory)' and reallocated its remaining value as it is understood to be an unused asset class going forward.
- Made determinations on other components of Essential Energy's proposal which also affect the forecast regulatory depreciation allowance—for example, the forecast capital expenditure (capex) (attachment 6) and the opening RAB value (attachment 2).[102]

Details of our approach in deriving the value of the regulatory depreciation allowance and relevant interrelationships are set out in attachment 5.

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99 NER, cl. 6.12.1(8) and 6.5.5(b).
100 NER, cl. 6.5.5(b).
101 NER, cl. 6.5.5(b)(1).
102 NER, cl. 6.5.5(a)(1).

8.6 Capital expenditure

Capex refers to the capital expenses incurred in the provision of network services. The return on and of forecast capex for standard control services are two of the building blocks we use to determine a service provider's total revenue requirement.

8.6.1 Draft decision

We are not satisfied that Essential's proposed total forecast capex of $2618 million ($2013-14) reasonably reflects the capex criteria. We therefore have not accepted Essential's proposal. Our alternative estimate of Essential's total forecast capex for the 2014–2019 period that we are satisfied reasonably reflects the capex criteria, is $1934.3 million as set out in Table 8–5.

Table 8–5 Our draft decision on total net capex ($million 2013–14)

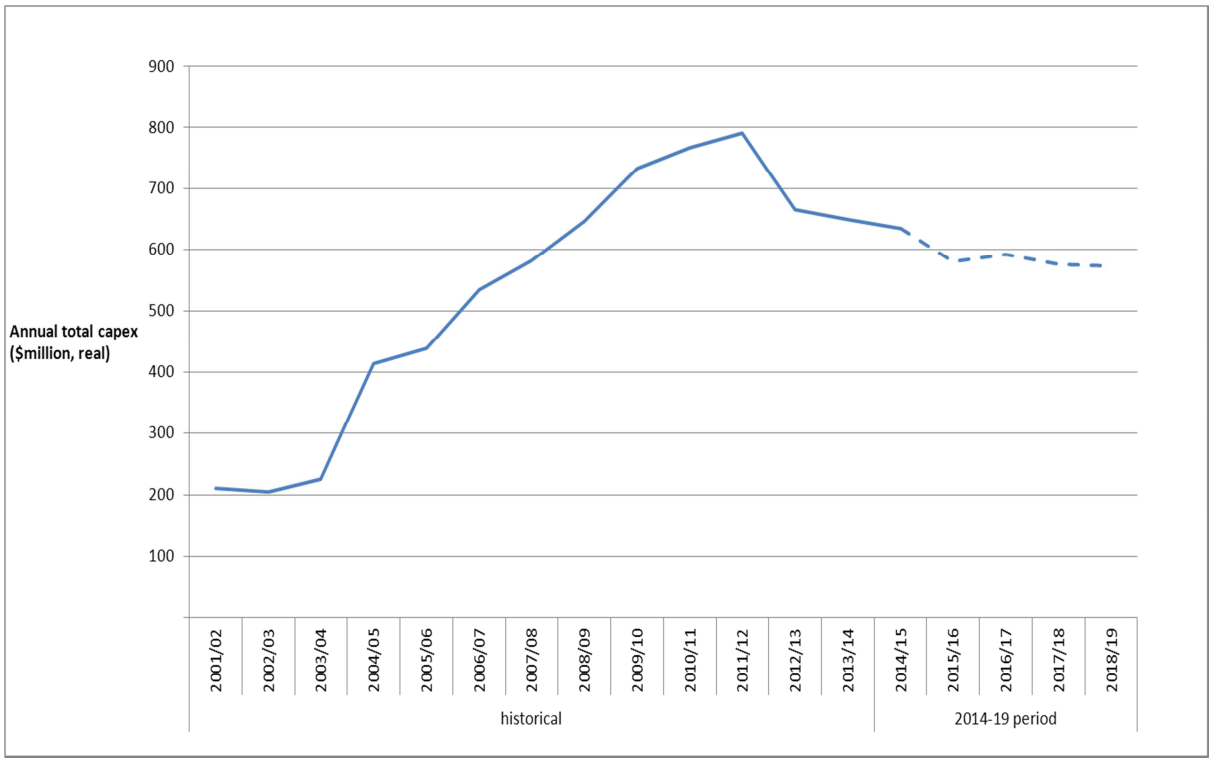
	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Essential's proposal	545.4	519.1	527.6	514.5	512.1	2618.7
AER draft decision	425.7	385.3	386.3	370.2	366.8	1934.3
Difference	119.7	133.8	141.3	144.3	145.3	684.4
	21.9%	25.8%	26.8%	28.0%	28.4%	26.1%

Source: AER analysis

8.6.2 Comparison of historical and forecast capital expenditure

Figure 8–3 shows the small decrease between Essential Energy's proposal for the 2014–2019 period and the actual capex that it spent in the 2009–14 period. Essential Energy's proposed forecast is, on average, higher than its average capex between 2001–02 and 2009–14.

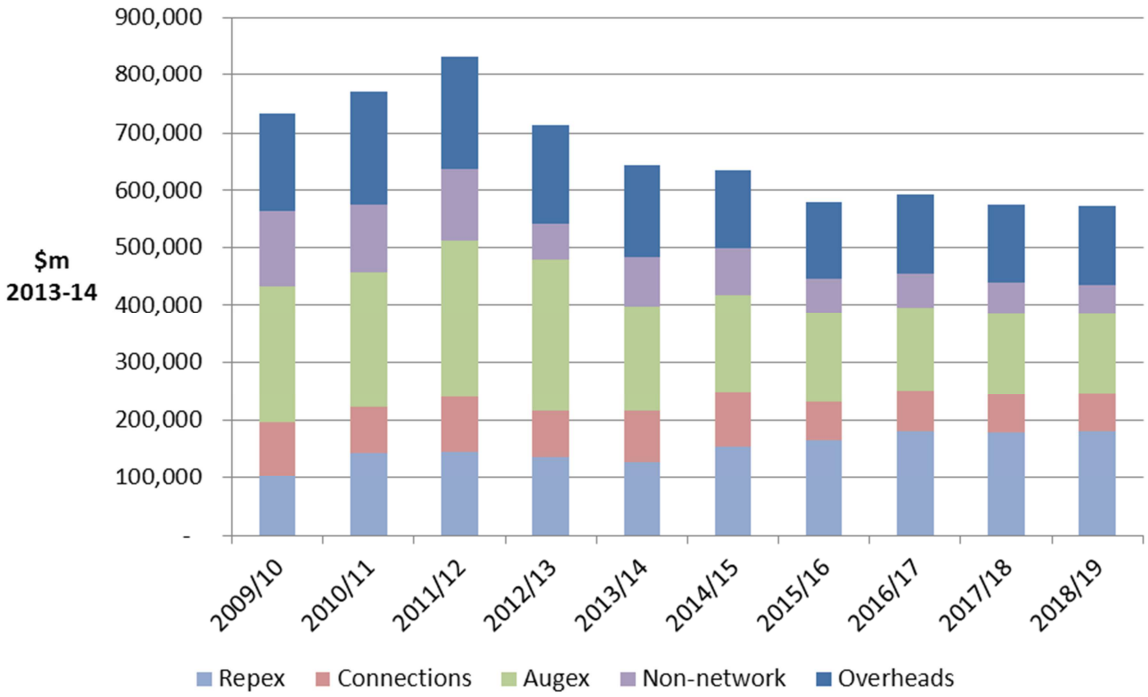
Figure 8–3 Essential Energy gross capex 2001-02 to 2018-19



Source: AER analysis, AER Annual RINs (2010/11 to 2013/14); 2014–2019 period: Essential Energy Reset RIN, Table 2.1.1 - Standard control services capex)

Figure 8-4 shows Essential Energy's capex drivers as a proportion of total capex. This shows that replacement expenditure (repex) has increased and remains relatively high compared with the reductions made in other areas of capex. The large reduction in augmentation capex (augex) is to be expected due to the expected slow growth in peak demand and the removal of the regulatory obligations on planning standards.

Figure 8-4 Essential Energy capex drivers as a proportion of total capex 2009-10 to 2018-19



Source: AER analysis, 2013–14 Essential Energy Consolidated RIN Template Public, Table 2.1, excluding balancing item

8.6.3 Summary of analysis and reasons

Forecasting methodology and past capex performance

Essential Energy's forecasting methodology applies a bottom-up assessment and does not have sufficient regard to top-down efficiency tests or delivery strategies. We consider a top down assessment is critical in deriving a total forecast capex allowance that reasonably reflects the capex criteria. We also find that Essential Energy's forecasting methodology incorporates an overly conservative risk assessment which does not adequately justify the timing and priority of its proposed forecast capex.

When we assessed Essential Energy's proposal and its historical capex performance against a number of metrics, we found that reductions of up to 50 per cent would be required to bring it in line with its peers. In particular, this is evident in the metrics of capex per customer, capex per maximum demand, capital partial productivity and multilateral total factor productivity (MTFP).

The techniques that we have employed in estimating a substitute capex forecast for the 2014–19 period are derived from a mix of top-down analysis, predictive modelling and adjustments to the bottom-up build submitted by Essential Energy. These are discussed below.

Replacement expenditure

Repex is non-demand driven capex. It involves replacing an asset with its modern equivalent where the asset has reached the end of its economic life. Economic life takes into account existing asset's age, condition, technology or operating environment.

Essential Energy proposed $857 million ($2013–14) of forecast repex (excluding overheads). We do not accept Essential Energy's proposal. We have instead included an amount of $675.7 million ($2013–14) in our alternative estimate. We do not accept Essential Energy's repex proposal on the basis that:

- Essential Energy's proposed forecast repex exceeds its long term average and controlling for network size compares unfavourably with other service providers in the NEM.
- In relation to the likely condition of Essential Energy's assets, the substantial increase in spare network capacity during the 2009–2014 period provides an operating environment that should reduce the rate of deterioration of Essential Energy's assets over the 2014–2019 period.
- Our expert independent consultant found that there are systemic issues with Essential Energy's forecast that mean its proposal is likely to significantly overstate the amount of repex required to meet the capex objectives. In particular, Essential Energy is likely to be replacing assets earlier than is necessary to meet the capex objectives.
- Our predictive modelling also suggests that Essential Energy's proposal is likely to be overstated and its asset replacement requirements are likely to be materially lower than the forecast.
- There is a real potential for Essential Energy to face deliverability constraints on the 2014–2019 period. This casts material doubt on whether Essential Energy's forecast repex is a realistic expectation of the cost inputs required to achieve the capex objectives.

Growth-related capex

Augmentation expenditure (augex)

Augex is typically triggered by a need to build or upgrade a network to address changes in demand or to comply with quality, reliability and security of supply requirements. Hence, the main driver of augex is maximum demand and its effect on network utilisation and reliability. The amount of augex that we have included in our substitute estimate of total capex is $475.2 m ($2013–14), excluding overheads. This is 36 per cent less than Essential's proposal of $744.6 million ($2013–14).

To arrive at this reduction we:

- reduced Essential Energy’s augex forecast by approximately 20.2 per cent to account for updated spatial demand forecasts provided by Essential Energy during the determination process
- applied a further 20 per cent reduction in light of independent engineering advice that suggests Essential Energy's forecast augex did not take account efficiencies that could be achieved through risk based cost benefit analysis assessment techniques in the context of the revisions to its licence conditions.

These reductions take into account the observed trend in augex that shows that there is excess capacity in Essential Energy's network that remains to be more efficiently utilised.

Customer Connections

We have accepted Essential's connections forecast of $366.1 million ($2013–14), excluding overheads, as it is consistent with the forecast drivers in construction activity in commercial and industrial, and multi-dwelling residential premises.

We also accept Essential Energy's proposed capital contributions forecast of $336.11 million, as we consider it is consistent with Essential Energy's forecast level of connection works which we are also accepting. We consider that capital contributions are mostly driven by connection and augmentation works. We expect Essential Energy to explain how capital contributions should be allocated to each service in its revised regulatory proposal.

Non-network expenditure

Non-network capex includes capex on information and communications technology (ICT), buildings and property, motor vehicles, and plant and equipment. Essential Energy forecast total non-network capex of $306.4 million for the 2014-19 period, a reduction of 46 per cent from actual capex in the 2009–14 regulatory control period. As part of our assessment of the total capex required for the 2014–19 period, we accept that Essential Energy's forecast of non-network capex is a reasonable estimate of the efficient costs required for this capex category. We have included it in our estimate of total capex for the 2014-19 period.

Capitalised overheads

We have included an allowance for capitalised overheads of $478.6 million ($2013–14) in our total capex estimate for the 2014–19 period. This amount maintains the average proportion of actual capitalised overheads to total capex of 32 per cent. We consider this proportion is reasonable taking into account historical data. Further, the reduction in direct capex and capitalised overheads proposed by Essential Energy from the 2009–14 to the 2014–19 period shows a linear relationship between direct capex and capitalised overheads.

8.7 Operating expenditure

Forecast opex is the forecast operating, maintenance and other non-capital costs incurred in the provision of distribution network services. It includes labour costs and other non-capital costs that a prudent service provider is likely to require during the 2014–19 regulatory control period for the efficient operation of its network.

8.7.1 Draft decision

We are not satisfied that Essential Energy's proposed total forecast opex reasonably reflects the opex criteria.[103] Our estimate of the total forecast opex Essential Energy would require over the forecast period is $1436.5 million ($2013–14). Our forecast is 38.4 per cent less than Essential Energy's forecast. Table 8–6 shows our draft decision on total opex compared to Essential Energy's proposal.

[103] NER, cl. 6A.6.6(c)

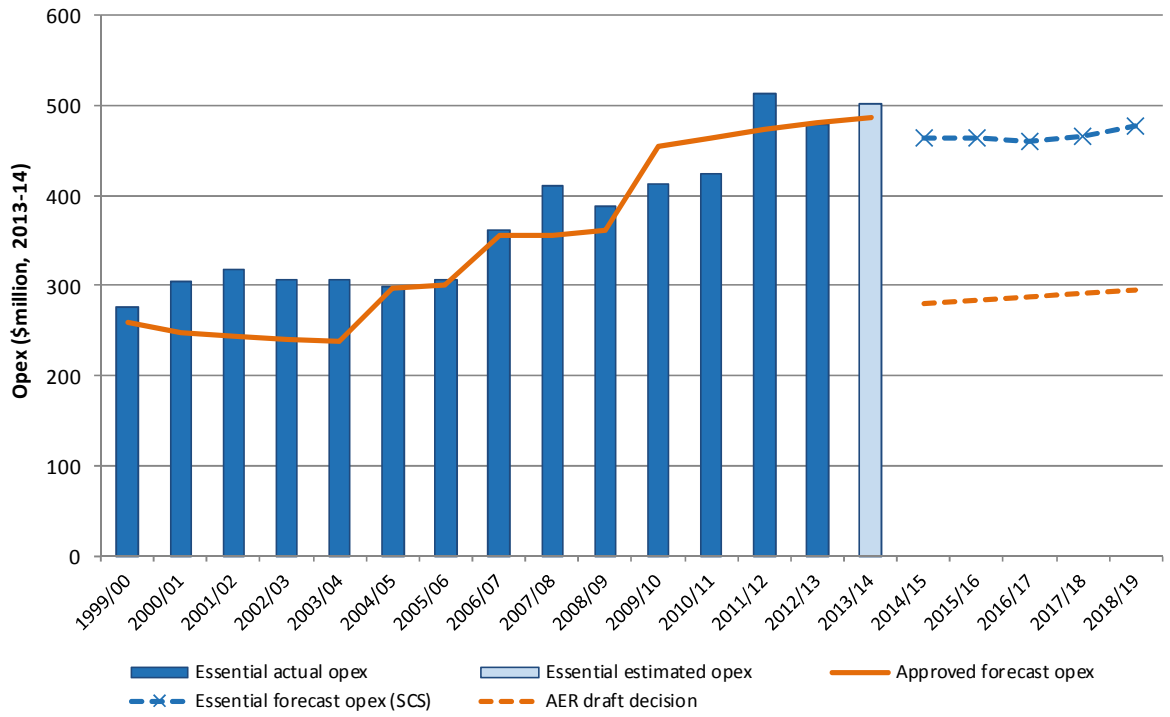
Table 8–6 AER draft decision and Essential Energy's proposed total opex ($million, 2013–14)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Essential Energy's proposal	463.1	464.9	460.6	466.8	476.4	2331.8
AER draft decision	280.7	283.4	286.9	290.9	294.7	1436.5
Difference	-182.4	-181.5	-173.7	-176.0	-181.7	-895.3

Source: AER analysis.
Note: Includes debt raising costs.

Figure 8-5 shows our draft decision compared to Essential Energy's proposal, its past allowances and past actual expenditure.

Figure 8-5 AER draft decision compared to Essential Energy's past and proposed opex ($million, 2013–14)



8.7.2 Summary of analysis and reasons

The main difference between our forecast and Essential Energy's forecast is the base amount of opex used to form the opex forecast (known as the 'base year'). Base opex forms the starting point for a forecast using our *Expenditure Forecast Assessment Guideline* (Guideline) opex forecasting approach.[104] Consistent with this approach, Essential Energy based its opex forecast primarily on the actual opex it incurred in 2012–13. However, while Essential Energy acknowledged that it is currently

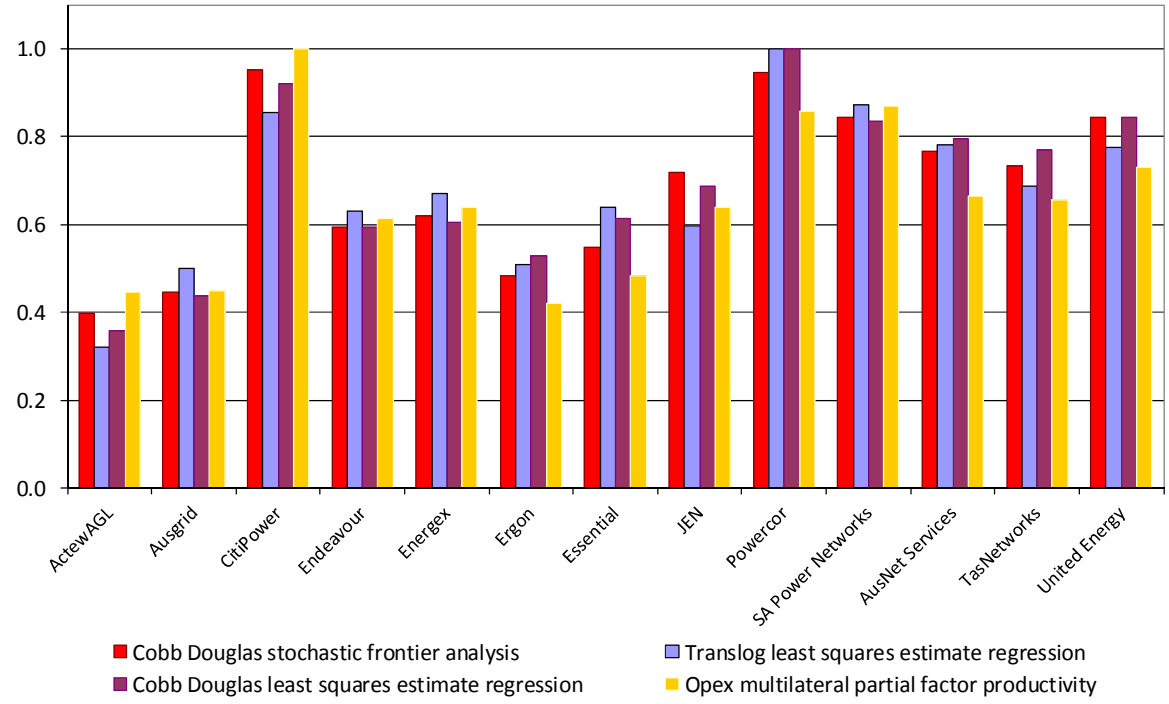
[104] Previously called the 'base-step-trend' approach or the 'revealed cost' approach.

incurring costs above efficient levels,[105] it has (after considering reclassified services) proposed similar levels of opex to the previous period.

Base opex

Consistent with the approach outlined in our Guideline, we tested the efficiency of Essential Energy's historical opex using a combination of assessment techniques. First, with the assistance of Economic Insights (our economic benchmarking consultant), we compared Essential Energy to its peers using several different benchmarking techniques, all of which showed a gap in performance between Essential Energy and the majority of its peers. Figure 8-6 demonstrates, for example, that Essential Energy's spends opex about 50 to 60 per cent as efficiently as the most efficient service providers in the NEM (CitiPower and Powercor) on four different measures.

Figure 8-6 Econometric modelling and opex MPFP results



Source: Economic Insights.

Other, simpler benchmarking techniques such as partial performance indicators and category analysis corroborate these results.

We also examined the potential sources of inefficiency or high costs that might explain the gap in performance between Essential Energy and its peers. This included detailed consideration by Deloitte Access Economics of Essential Energy's labour and workforce practices. We are satisfied that our detailed review provides evidence of inefficiency in Essential Energy's historical opex, including in the base year.

Deloitte Access Economics found in respect of the labour costs incurred in delivering the capex program (labour-related capex), there is evidence to suggest that the expenditure and approach to

[105] See, for example, Essential, Regulatory Proposal, p. 78; Networks NSW, Delivering Efficiencies for our customers. June 2014, p. 4; NSW DSNPs, Submission on AER issues paper, 8 August 2014, pp. 12–16.

resourcing the program was not consistent with that of a prudent or efficient service provider. In particular:[106]

- Essential Energy seems to have relied too heavily on hiring permanent internal labour resources rather than using temporary external contractors to undertake the capex program
- labour related capex was impacted by a unionised workforce that was relatively inflexible, high-cost and unproductive compared to their peers.

Deloitte Access Economics considered the base year would not likely represent efficient costs because for much of the 2009–14 regulatory period it appears likely that Essential Energy's labour costs were impacted by:[107]

- A relatively inflexible workforce with limited ability to innovate or respond to changing circumstances
- Labour costs entrenched in Enterprise Bargaining Agreements (EBAs) which are well above peer costs
- In some cases, poor management of labour costs – for example in relation to overtime
- Union opposition to management attempts to reduce costs and/or improve productivity.

Deloitte found that Networks NSW had identified significant efficiency improvements with the NSW service providers but noted:[108]

> While some savings have already been identified and realised, the reforms are only in their early stages and therefore it is likely that the full benefits of the current NNSW efficiency programs will not be realised until the 2014-19 regulatory period. In particular, due to these anticipated future efficiencies, it is in our view unlikely that the opex base year (2012-13) reflects efficient labour costs.

We consider this is supporting evidence driving some of the scope for our proposed base opex adjustments.

Through our review of Essential Energy's vegetation management practices, we discovered material inefficiency arising from its contractor management and largely reactive approach to vegetation clearance. Acknowledging its past inefficiency, Essential Energy has proposed a step decrease in vegetation management in the forecast period.

Direct comparison shows that Essential Energy incurred similar total opex to the sum of Powercor and SA Power Networks over the past eight years despite Essential Energy serving only 54 per cent of the customers and operating a network that experiences only 47 per cent of the peak demand of Powercor and SA Power Network's combined networks.

Essential Energy acknowledges scope for improvement exists. In its submission it proposes $292 million in opex efficiency savings (excluding $95 million of implementation costs), including management saving initiatives and network reform project initiatives.[109] Vince Graham, CEO of Networks NSW, has also identified high labour costs as an issue for Essential Energy:[110]

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106 Deloitte, *NSW Distribution Network Service Providers Labour Analysis*, pp. i–v.
107 Deloitte, *NSW Distribution Network Service Providers Labour Analysis*, pp. i–v.
108 Deloitte, *NSW Distribution Network Service Providers Labour Analysis*, p. iv.
109 Essential, *Regulatory Proposal*, May 2014, pp. 73, 79.
110 Vince Graham, Selling off electricity networks will give NSW cheaper power bills, The Australian, 20 August 2014.

> Public ownership, politically powerful unions and amenable management have all combined to deliver union agreements that drive higher labour costs and higher electricity bills. We employ 12,000 NSW workers at a labour cost of more than $1.5bn a year. Labour costs are about 70 per cent of our operating costs. Labour costs and labour productivity are important drivers of electricity network charges. For many years under government ownership, NSW unions have exercised a "shadow management" role, entrenching unproductive and uncompetitive work practices.

Following our analysis using a combination of techniques, we are satisfied a forecast based on Essential Energy's historical opex would not reasonably reflect the opex criteria. Therefore, an adjustment is necessary. We have used our preferred benchmarking model as the starting point to arrive at an alternative estimate of what we consider reasonably reflects an efficient base level of opex. However, we consider the following adjustments are necessary:

1. We have provided a further 10 per cent allowance for those operating environment differences not completely captured by our preferred benchmarking model.
2. We have compared Essential Energy's efficiency to a weighted average of all networks with efficiency scores above 0.75 (CitiPower, Powercor, United Energy, SA Power Networks and AusNet) rather than the most efficient service provider (CitiPower) in our preferred model.

Based on this adjustment, Essential Energy's forecast opex will be lower than current levels. This raises the issue of whether it is appropriate to allow Essential Energy to transition over time from its current level of expenditure to what we have determined as efficient expenditure.

On the information before us, we are not satisfied that Essential Energy has made a sufficiently robust argument for why consumers should share in funding Essential Energy's transition to an efficient revenue allowance. Moreover, it is not clear from the information before us that this is consistent with the incentive framework provided by the NEL and the NER. We will, however, consider the issue further in view of any submissions received on this matter in response to our draft decision.

Rate of change

We have trended forward our estimate of efficient base opex to account for efficient changes over time an efficient provider would incur. This includes factors such as expected growth in labour prices, growth in Essential Energy's customer base, and its network. We have used a different methodology to Essential Energy to determine this trend.

Step changes

In addition, our opex forecast is also different to Essential Energy's because we reached a different view to Essential Energy on several other elements of its opex.

For instance, Essential Energy's opex forecast included an increase in opex for its network reform program. We consider that Essential Energy's network reform program is needed only because it is not currently operating efficiently. Consistent with our views about transition paths, our draft decision opex forecast does not include restructuring costs.

8.8 Corporate income tax

The estimated cost of corporate income tax contributes to our determination of the total revenue requirements for Essential Energy over the 2014–19 period. An allowance for corporate income tax enables Essential Energy to recover the costs associated with the estimated corporate income tax payable during that period. Attachment 8 sets out our detailed reasons for our draft decision on Essential Energy's estimated cost of corporate income tax.

8.8.1 Draft decision

We forecast Essential Energy's corporate income tax allowance at $217.9 million ($ nominal). Table 8–7 sets out our draft decision on Essential Energy's corporate income tax allowance for the 2014–19 period. Our draft decision is 60.3 per cent less than the allowance Essential Energy proposed.

Table 8–7 AER's draft decision on Essential Energy's cost of corporate income tax allowance for the 2014–19 period ($ million, nominal)

	2014–15	2015–16	2016–17	2017–18	2018–19	Total
Tax payable	66.9	63.6	78.4	77.8	76.6	363.2
Less: value of imputation credits	26.8	25.4	31.4	31.1	30.6	145.3
Corporate income tax allowance	40.1	38.1	47.1	46.7	46.0	217.9

Source: AER analysis.

8.8.2 Summary of analysis and reasons

We do not accept Essential Energy's proposed cost of corporate income tax allowance of $382.7 million ($ nominal) for the 2014–19 period. Instead, we determine the cost of corporate income tax allowance of $217.9 million ($ nominal) for Essential Energy. Our draft decision reflects our amendments to some of Essential Energy's proposed inputs for forecasting the cost of corporate income tax such as the opening tax asset base, and the standard and remaining tax asset lives. It also reflects our draft decision on the value of imputation credits—gamma—discussed in attachment 4. Our draft decision changes to other building block costs that affect revenues also impact the tax calculation.

Details of our approach in deriving the value of the corporate income tax allowance and relevant interrelationships are set out in attachment 8.

8.9 Classification of services and control mechanisms

Service classification determines the nature of economic regulation, if any, applicable to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and those services we will not regulate. Our decision reflects our assessment of a number of factors, including existing and potential competition to supply these services.

The control mechanism (how we determine prices for the services we classify) for standard control services specifies how Essential Energy's total annual revenue requirement will change from year to year. In our Stage 1 Framework and Approach (F&A) for Essential Energy, we decided to apply a revenue cap control mechanism to Essential Energy's standard control services for the 2014–19 regulatory control period.

8.9.1 Draft decision

Our draft decision is to maintain the approach adopted in the Stage 1 F&A[111] including our decision that separates regulated metering charges from standard control services by unbundling metering charges through an alternative control service classification. The NSW distributors adopted our

[111] NER, cl. 6.12.1(1).

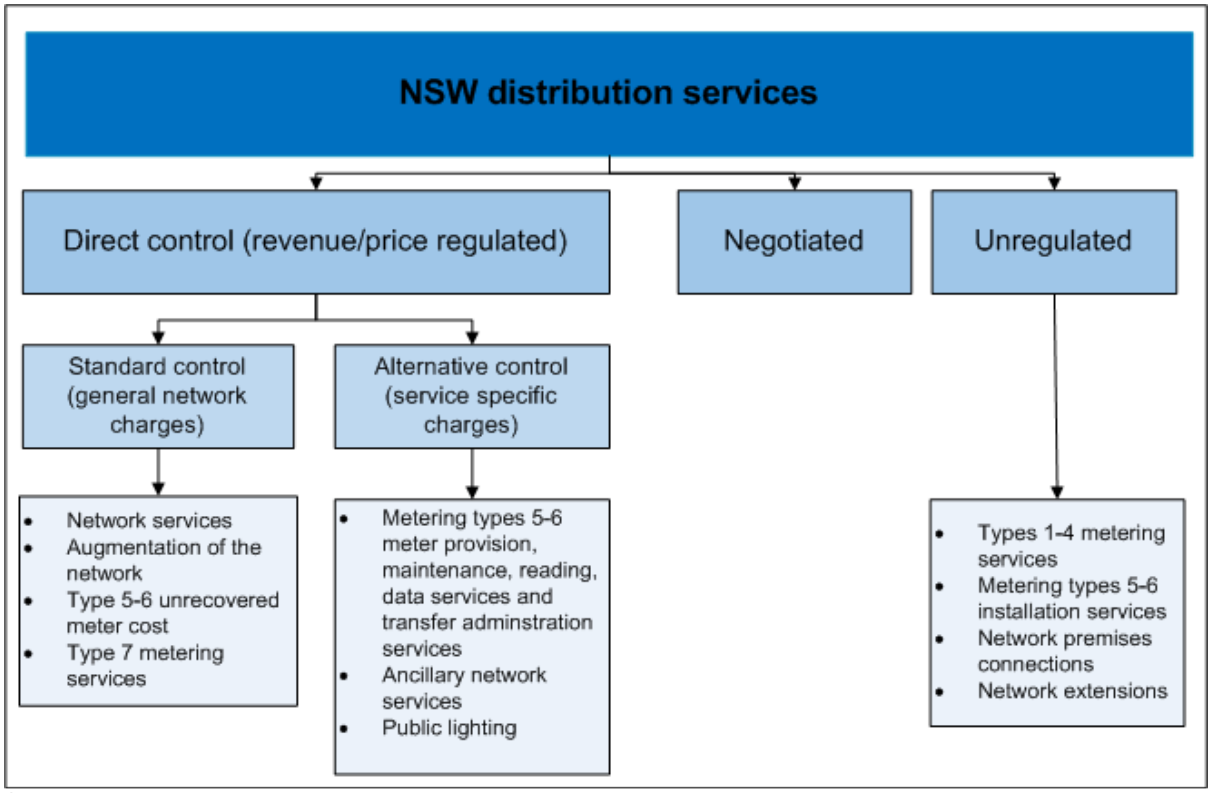
proposed classification in their regulatory proposals. However, the NSW distributors also proposed an additional metering service called a metering exit fee. Our detailed consideration and approach to exit fees is set out in attachment 16. We agree that some additions to metering classification are required and we summarise our reasons for these adjustments below.

We have also decided to:

- classify the recovery of the NSW distributors' residual type 5 or 6 meter costs as a standard control service
- classify the administration costs for type 5 and 6 meter transfers as an alternative control service
- clarify some descriptions of services, as set out in the table is distribution services at attachment 13. In particular, network services include load control where this is initiated by a distributor and metering services are inclusive of load control devices where these are embedded in a meter.

Figure 8-7 shows our draft decision on service classifications for the 2015–19 regulatory control period.

Figure 8-7 AER draft decision on 2015–19 service classifications for the NSW distributors



Source: AER

As indicated in Figure 8-7, our draft decision is not to classify any distribution services as negotiated distribution services for the 2015–19 regulatory control period.

Our assessment of the classification of services determines how costs associated with the services will be recovered at a very high level. That is, whether the costs of a particular service will be recovered from basic electricity charges, as an additional charge or not recovered at all, as mentioned

earlier. However, the detailed prescription of how service charges are set is not determined as part of classification; instead, that detail is discussed in the control mechanisms attachment 14.[112]

8.9.2 Summary of analysis and reasons

Our decision is to maintain the approach adopted in the Stage 1 F&A including our decision that separates regulated metering charges from standard control services by unbundling metering charges through an alternative control service classification. The NSW distributors adopted our proposed classification in their regulatory proposals. However, the NSW distributors also proposed an additional metering service called a metering exit fee. Our detailed consideration and approach to exit fees is set out in attachment 16. We agree that some additions to metering classification are required and we summarise our reasons for these adjustments below.

In attachment 16 we explain that we do not accept the administrative charges proposed by the NSW distributors that are associated with customers switching to an alternative metering provider. However, we consider it prudent to indicate how we would classify such a service in the event that the NSW distributors are able to provide sufficient justification leading into our final decision. These costs, if substantiated, would be directly attributable to a customer seeking to switch meter providers. On this basis we are satisfied the service 'meter transfers' should be classified as an alternative control service.

The NSW distributors proposed exit fees that would allow them to recover costs associated with metering assets made redundant when a customer switches to an alternative metering provider. As explained further in attachment 16, we have not accepted this approach. The NEL and NER require us to have regard to the development of competition in deciding appropriate service classification.[113] As argued in submissions, an exit fee may impede the development of competition in the provision of metering services. We have therefore classified this service as a standard control service with the costs to be recovered from all customers.[114]

We have also refined the definitions of network services (standard control) and metering services (alternative control) to make clear our intended approach to the classification of load control services. Load control permits a distributor to control an appliance like hot water units (load) connected at a customer's premises. Distributors use controlled load to reduce demand on the network at peak periods. By doing so, the distributors avoid the need for more expensive investment in network augmentation.

The NSW distributors proposed that load control devices remain standard control services.[115] While we acknowledge the distributors rely on load control to manage their networks, we do not accept that load control services need to be classified as standard control or that load control devices need to be a part of the RAB. Rather, load control can be achieved through arrangements with customers, through tariff or other agreements, which give a customer an incentive or reason to allow a distributor to have control over the customer's load. Consequently, we do not agree that load control devices embedded in a meter should be exclusively classified as standard control. We discuss this delineation further in attachment 13.

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112 See attachment14 for standard control services and attachment 16 for alternative control services.

113 NEL, s. 2F and NER, cl. 6.2.2(c)(1).

114 For example, Vector Limited, *Submission on issues paper on NSW electricity distribution regulatory proposals*, 8 August 2014, p. 2; AGL, *NSW electricity distribution networks regulatory proposals: 2014–19*, 8 August 2014, pp. 21–24; Origin, *Submission to NSW electricity distributors' regulatory proposals*, 8 August 2014, pp. 33–36.

115 Networks NSW response to AER information request AER NNSW 007 received on 4 August 2014.

8.10 Alternative control services

Alternative control services do not form part of Essential Energy's revenue cap. Rather, the prices of these services are set individually. In our Stage 1 F&A we proposed to classify the following services as alternative control services:[116]

- type 5 and 6 metering services – for provision, maintenance, reading and data services
- public lighting – repair, replacement and maintenance of existing public lighting assets and the provision of new public lighting assets or emerging public lighting technology
- ancillary network services – ad hoc services provided on an 'as needs' basis to customers that are charged on either a fee basis or quote.

8.10.1 Draft decision

In accordance with our Stage 1 F&A, we have decided that the form of control mechanism to apply to Essential Energy's alternative control services will be price caps.[117] Essential Energy should demonstrate compliance with the control mechanism through an annual pricing proposal.[118]

The basis of the control mechanism for alternative control services must be determined in the distribution determination.[119] Our draft decision on the basis of the control mechanism for each type of alternative control service is:

- type 5 and 6 metering services (provision, maintenance, reading and data services) – price cap
- public lighting services – price cap
- ancillary network services – price cap

8.10.2 Summary of analysis and reasons

Our decision is to maintain the approach adopted in the Stage 1 F&A including our decision that type 5 and 6 metering provision, public lighting services and ancillary network services will be alternative control services. Attachment 16 discusses this in more detail.

We have explained in attachment 16 why we do not accept Essential Energy's proposed annual type 5 and 6 metering charges. Essential Energy's proposed structure of metering service tariffs included an:

- annual metering service charge recovering the cost of existing or replacement meters and operating expenditure for new or upgraded meters
- upfront charge for new or upgraded meters
- exit fee recovering the residual meter and administration costs, in the event that a customer transfers to an alternative metering provider.

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116 AER, *Stage 1 Framework and approach for Ausgrid, Endeavour Energy and Essential Energy*, 2014–19, March 2013, p. 15.
117 AER, *Stage 1 Framework and approach for Ausgrid, Endeavour Energy and Essential Energy*, 2014–19, March 2013, pp. 10 and 43–62.
118 NER, cl. 6.12.1(13) and 6.18.
119 NER, cl. 6.2.6(b).

The Australian Energy Market Commission (AEMC) is presently in the process of making a rule change that would expand competition in metering and related services to help facilitate a market led roll out of advanced metering technology.[120]

We have sought to create a regulatory framework for the 2015-19 regulatory period which will be robust enough to handle the transition to competition once the rule change takes effect. This involves having transparent standalone prices for all new/upgraded meter connections and annual charges.

Our decision does not accept Essential Energy's:

- annual metering service charge because the forecast capital and labour costs do not reasonably reflect the efficient costs of a prudent operator
- price caps for new and upgraded connections for similar reasons
- proposal to charge an exit fee to leaving customers to recover residual metering costs. Instead residual metering costs will be classified as a standard control service and recovered from the general network customer base to avoid creating a regulatory barrier to competitive entry.

The result of our decision is there will be no exit fee. However, we accept in principle that an exit fee that recovers the efficient incremental costs of a customer transfer is appropriate. In Essential Energy's case, the administrative cost component was not substantiated.

Public lighting operation, maintenance and replacement charges and service delivery received much comment from stakeholders. We have reduced the proposed price increases for 2015–16 because we considered that Essential Energy's input cost assumptions do not reflect efficient service provision. For the remaining years of the regulatory control period, small annual increases have been approved.

Our draft decision is to accept the step increase in charges for ancillary network services from those during 2009–14. This is because we have reclassified quoted and fee based activities from standard control services to alternative control services. The result is that customers choosing these services now bear the full costs of their provision rather than being subsidised by all electricity users. Nonetheless, customers will receive a small offsetting reduction in Essential Energy's standard control services revenue (and therefore tariffs) to compensate for this.

[120] AEMC, *Expanding competition in metering and related services in the National Electricity Market, Consultation Paper*, 17 April 2014

9 Incentive schemes

Incentive schemes are a component of incentive-based regulation and complement our approach to assessing efficient costs. Under our incentive schemes, businesses are given financial rewards where they improve their efficiency and spend less than forecast during the regulatory period. Businesses may also be rewarded for efficient improvements in service quality, or be given an allowance to investigate and conduct demand management projects.

We apply incentive schemes to regulated businesses at the time of making our determinations, and may or may not apply a particular scheme, depending on the circumstances.

The AER's four incentive schemes are:

- The efficiency benefit sharing scheme (EBSS)
- The capital expenditure sharing scheme (CESS)
- The service target performance incentive scheme (STPIS)
- The demand management incentive scheme (DMIS).

9.1 Efficiency benefit sharing scheme

The efficiency benefit sharing scheme (EBSS) provides an additional incentive for service providers to pursue efficiency improvements in opex.

To encourage a service provider to become more efficient it is allowed to keep any difference between its approved forecast and its actual opex during a regulatory control period. Conversely, if it overspends its allowed opex, it cannot seek to recover this. This is supplemented by the EBSS which provides the service provider with an additional reward for reductions in opex it makes and additional penalties for increases in opex. In total these rewards and penalties work together to provide a constant incentive for a service provider to pursue efficiency gains over the regulatory control period. The EBSS also discourages a service provider from overspending its opex allowance in what it expects will be the base year for the following regulatory control period, in order to receive a higher opex allowance in that period.

9.1.1 Carryover amounts accrued during the 2009–14 regulatory control period

During the 2009–14 regulatory control period Essential Energy operated under the *EBSS for the ACT and NSW 2009 distribution determinations*, which was released in February 2008.[121] Our draft decision is not to apply EBSS carryover amounts that Essential Energy has accrued during that period.

Essential Energy has accrued EBSS penalties from the operation of the EBSS in the 2009–14 regulatory control period. When considering the adjustment we have made to Essential Energy's opex based on benchmarking, we consider that also applying EBSS penalties would excessively penalise Essential Energy for efficiency losses it made during the 2009–14 regulatory control period. We are not satisfied this would not give effect to fair sharing of efficiency losses as required under the NER.

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[121] AER, *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, February 2008.

9.1.2 Application of the EBSS during the 2015–19 regulatory control period

Our draft decision is that no expenditure will be subject to the EBSS in the 2015–19 regulatory control period., We have made this decision because of our forecasting approach to opex and the likely incentives Essential Energy already faces to improve its efficiency. This also means that no expenditure will be subject to the EBSS in the 2014–15 regulatory control period.

9.2 Capital expenditure sharing scheme

The capital expenditure sharing scheme (CESS) provides financial rewards for network service providers whose capex becomes more efficient and financial penalties for those that become less efficient. Consumers benefit from improved efficiency through lower regulated prices.

As part of the Better Regulation program we consulted on and published the capital expenditure incentive guideline, which sets out version 1 of the CESS.[1] The CESS approximates efficiency gains and efficiency losses by calculating the difference between forecast and actual capex. It shares these gains or losses between service providers and consumers.

Under the CESS a service provider retains 30 per cent of the benefit or cost of an underspend or overspend, while consumers retain 70 per cent of the benefit or cost of an underspend or overspend. This means that for a one dollar saving in capex the service provider keeps 30 cents of the benefit while consumers keep 70 cents of the benefit. Conversely, in the case of an overspend, the service provider pays for 30 cents of the cost while consumers bear 70 cents of the cost.

9.2.1 Draft decision

We will apply version 1 of the CESS as set out the capital expenditure incentives guideline to Essential Energy in the 2015–19 regulatory control period.

9.2.2 Summary of analysis and reasons

Essential Energy proposed to apply the CESS as set out in the capex incentives guideline, but with additional exclusions.

In deciding how to apply the CESS to Essential Energy we have taken into account our decision not to apply the EBSS to in the 2015–19 regulatory control period. We are satisfied that we should apply the CESS when the EBSS does not apply. Without a CESS the incentive for a service provider to spend less than its forecast capex declines throughout the period. The CESS works to provide a continuous incentive for a service provider to seek capex efficiencies throughout the regulatory period. The way in which capex underspends and overspends are shared occurs independently of how the EBSS applies. So even when the EBSS does not apply, the CESS will still provide a service provider with the same reward and penalty in each year of a regulatory control period for capex underspends or overspends.

9.3 Service target performance incentive scheme

This service target performance incentive scheme (STPIS) has two components, the s-factor component and the guaranteed service levels (GSL) scheme. The s-factor component adjusts the revenue that a distributor earns depending on reliability of supply and customer service performance. The GSL scheme sets threshold levels of service for distributors to achieve and requires direct

[1] AER, *Capex incentive guideline*, November 2013, pp. 5–9.

payment to customers who experience service worse than the predetermined level. We do not propose to apply the guaranteed service level component (GSL) because NSW DNSPs are subject to jurisdictional GSL arrangements.

The scheme provides financial incentive for distributors to maintain and improve their performance. The STPIS balances the incentive in the regulatory framework for distributors to reduce costs at the expense of service performance. Cost reductions are beneficial to both distributors and their customers when service performance is maintained or improved. However, cost efficiencies achieved at the expense of service performance may not be desirable.

The STPIS establishes targets based on historical performance, and provides financial rewards for distributors exceeding performance targets and financial penalties for distributors failing to meet targets. These rewards and penalties are calculated by taking into account value of customer reliability (VCR). This aligns the distributors' incentives with the long term interest of consumer.

9.3.1 Draft decision

Consistent with our Stage 2 F&A and Essential Energy's proposal, we will apply the s-factor component of our national STPIS to Essential Energy for the 2015–19 regulatory control period.

9.3.2 Summary of analysis and reasons

We adjusted Essential Energy's performance targets to account for the historical expenditure for improving supply security and reliability. Based on observed trend, we propose to set the performance targets for System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) at 3.41 and 7.69 per cent below the respective latest 5-regulatory year average performance levels. We consider that these adjustments are important and will ensure that the reliability improvement resulting from past capital expenditures are retained, because customers are paying for such historical investment on an ongoing manner.

We propose that the incentive rates under the scheme should be based on the VCR values published by AEMO in September 2014 because we consider AEMO's VCR values are determined through a robust method and represent the best available information for this purpose.

We accept Essential Energy's proposal to cap revenue at risk under the scheme at ±2.5 per cent. Within this there will be a cap of ±2.25 per cent for the reliability of supply component and ±0.25 per cent for the customer service component. We consider this lower powered incentive would balance the risk to both consumers and Essential Energy and thus better meet the objectives of the STPIS.

We adjusted Essential Energy's proposed performance target for emergency call centre answering calls within 30 seconds based on benchmarking with Victorian distributors.

9.4 Demand management incentive scheme

The demand management incentive scheme (DMIS) includes a demand management innovation allowance (DMIA). The DMIA is a capped allowance for distributors to investigate and conduct broad based and/or peak demand management projects.

9.4.1 Draft decision

We have determined to continue Part A of the Demand Management Innovation Allowance (DMIA) but will not apply either Part B of the DMIA or the D-factor scheme for Essential Energy in the 2015–

19 regulatory control period. This is consistent with our proposed approach in the Stage 2 Framework and Approach.

The current innovation allowance amount of $0.6 million ($2014–15) per annum will continue in the 2015–19 regulatory period.

9.4.2 Summary of analysis and reasons

The development and implementation of a new demand management and incentive scheme (DMIS) for the 2015–19 regulatory control period depends on the progress of the rule change process arising from the AEMC's Power of Choice review. At the time of this decision, the AEMC has not yet commenced consultation on the rule change.

We agree that demand management is important and the existing incentive arrangements need to be reformed. A benefit sharing scheme, such as that proposed by Essential Energy, could well be effective in strengthening incentives in this regard. We do not intend to pre-empt consultation on the AEMC's review of the current demand management arrangements by commencing a separate consultation process on a new DMIS before the outcomes of the review are finalised.

10 Consumer engagement

AER's views on effectiveness of Essential Energy's consumer engagement

The AEMC intended that the AER have regard to the nature of consumer engagement undertaken and the outcomes of that engagement.[122]

While acknowledging efforts from Essential Energy to improve its engagement with its consumers, we consider that Essential Energy has significant work to do to give consumers more say in the services it provides. We base this view on stakeholder submissions and from our own observations of the engagement activities Essential Energy undertook, particularly in relation to metering and public lighting. We recognise that genuine consumer engagement takes time to build, and expect that Essential Energy will continue to build on the work it is already undertaking in this area.

AER consumer engagement guideline for service providers

The AEMC intended that the AER have regard to the nature of consumer engagement undertaken and the outcomes of that engagement in considering the proposals put to it by network service providers.[123] To assist service providers, we developed a consumer engagement guideline for network service providers.[124] Our consumer engagement guideline centres on best practice principles which seek to drive consumer engagement and a commitment from service providers to continuously improve engagement across all business operations. Our guideline is not prescriptive but rather places the onus on service providers to develop consumer engagement strategies and activities that best suit their business. Service providers can do this most appropriately because they are in the best position to understand their consumer base and its issues.

We acknowledge that our consumer engagement guideline has only been in effect since November 2013. Therefore, most network service providers' consumer engagement strategies are reflective of the consumer engagement approaches they already had in place. Since the release of the guideline, most service providers have made steps to improve and implement a consumer engagement strategy in line with our guideline to support their proposals. We encourage all service providers to continue in this positive direction. We also recommend that service providers review stakeholder and Consumer Challenge Panel submissions and consult with them on how their consumer engagement strategies can be improved to provide ongoing and genuine engagement and demonstrate how stakeholder input has shaped future proposals and broader business decisions.

Ultimately, we expect service providers to undertake systematic, consistent and strategic engagement with consumers on issues significant to both parties. As set out in our consumer engagement guideline, we have considered how the service provider:

- equipped consumers to participate in consultation
- made issues tangible to consumers
- obtained a cross section of views
- considered and responded to consumer views

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122 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, p. 36.

123 AEMC, *Rule Determination National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, p. 36.

124 AER, *Consumer engagement guideline for network service providers*, November 2013.

We have made this assessment drawing on the service provider's proposal and submissions from the CCP and other stakeholders. We have also had regard to the extent to which each service providers' opex and capex proposals reflect consumer concerns.[125] Our assessment of these opex and capex factors is detailed in the respective opex and capex attachments.

Equipped consumers to participate in consultation and made issues tangible to consumers

Essential Energy has focused its engagement activity around a number of key channels including customer and stakeholder surveys, focus groups, direct consultation and feedback sessions, and social media channels.[126] From submissions, we have identified several areas where stakeholders have not been equipped to participate or where issues have not been made tangible to consumers. These are public lighting, metering charges and rate of return.

With regards to public lighting, many of Essential Energy's public lighting customers were clearly surprised by the significant price increases proposed in its regulatory proposal. This is evident from the large number of submissions received from Regional NSW councils. The submissions clearly indicated that Essential Energy did not meaningfully engage with its customers during the development of its regulatory proposal. Since the lodgement of its regulatory proposal, Essential Energy has taken positive steps to consult with its public lighting customers through the establishment of its Street lighting Consultative Committee.

Essential Energy has also taken positive steps in making its public lighting charges tangible to consumers. Since lodgement of its regulatory proposal, Essential Energy has withdrawn the confidentiality claims it had previously made over public lighting documents.

In relation to metering charges, we published a discussion paper on the topic in December 2012 and confirmed our position in our Stage 1 F&A published in March 2013. During that time, we suggested that Essential Energy consult with its customers on the range of options that might be available. There is little evidence that Essential Energy consulted customers on options for how meters could be priced in the future. Networks NSW did conduct a workshop with retailers in May 2014 to provide advanced notice of the metering charges in its proposal, but our understanding is that Essential Energy did not otherwise consult on its proposed charges. The absence of this consultation is reflected in submissions from Origin and PIAC which indicate that Essential Energy has developed its metering proposal independent from consumers. Given the significant impact the metering exit fees proposed by Essential Energy would have on consumers, we hosted a workshop on 11 September 2014 to hear from stakeholders.

There was also broad stakeholder disappointment that Essential Energy departed from our rate of return guideline with little or no consultation with consumers and without demonstrating that these variations are made in the long-term interests of consumers or represent the efficient costs of an efficient benchmark firm.[127]

The three issues outlined above are relevant concerns identified by consumers. However, Essential Energy's overview and its proposal more broadly do not sufficiently detail how Essential Energy has

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125 NER, cl. 6.5.6(e)(5A) and 6.5.7(e)(5A) for electricity distribution.
126 Essential Energy, Stakeholder Engagement Framework, May 2014, p. 8.
127 PIAC, *Submission,* p. 11.

engaged and sought to address these concerns or describe the key risks and benefits for electricity consumers.[128]

The CCP and other stakeholders submitted that Essential Energy could do more to make issues tangible to consumers. For example, Origin stated that to promote constructive and informed contributions from stakeholders it is imperative that the data and information that underpin a regulatory review process be presented to stakeholders in a manner that is, to every extent practicable, transparent and comparable across each of the regulatory reporting documents and over time.[129] Along similar lines, the CCP submitted that the NSW distribution network businesses are not providing consumers with sufficient and relevant information as part of their consumer engagement activities.[130] To make issues more tangible to consumers, we expect that Essential Energy will make more effort to provide various consumer groups with the information they need to participate.

Obtained a cross section of views and responded to a cross section of stakeholder views

Through the documents submitted with its regulatory proposal, it is clear that Essential Energy has taken steps to improve its customer engagement. We encourage Essential Energy to continue developing is customer engagement channels. The Ethnic Communities' Council of NSW outlined possible areas where Essential Energy could better target its engagement to include reach consumers from culturally and linguistically diverse backgrounds who often have limited internet access or English skills to respond to complex questions.[131]

Essential Energy's consideration and response to consumer views obtained throughout its engagement activities has been questioned by a number of submissions. It is apparent from the submissions that Essential Energy has not engaged with stakeholder input and reflected how it has used that input to shape its proposal. This is particularly evident in relation to metering and public lighting.

The CCP posed a number of stretch questions to consider when assessing NSP claims about their consumer engagement activities.[132] Without considering all the stretch questions here, it is suffice to say that Essential Energy has made an attempt to engage with, and seek feedback from, various consumer cohorts. This is evident from the participation of the Networks NSW CEO and Essential Energy Chief Operating Officer at various stakeholder engagement events. However, submissions clearly question whether Essential Energy's regulatory proposal aligns with, and has taken into account, consumer expectations and preferences.

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128 NER, cl. 6.8.2(c1).
129 Origin, *Submission,* p. 6.
130 CCP, *Submission,* p. 7.
131 Ethnic Communities' Council of NSW, *Submission,* p. 2.
132 CCP, *Submission,* p. 13.

11 Next steps

If our draft decision requires Essential Energy to make changes or address matters, then it may submit a revised regulatory proposal in response to our draft decision.[133] Essential Energy must submit the revised regulatory proposal to us within 30 business days of publication of our draft decision.[134] We must invite written submissions on the draft decision once we publish that decision, a notice of the making of that draft decision, and a notice of a predetermination conference.[135] Any person may attend the predetermination conference and make a written submission on our draft decision. The due date for written submissions must not be earlier than 30 business days after the making of the draft decision.[136]

After considering submissions made on the draft decision and any revised revenue proposal, we must make a final decision and distribution determination.[137] Key dates for our assessment process are set out in Table 11–1 below.

Table 11–1 Key dates for our assessment process

Task	Date
Essential Energy's regulatory proposal submitted to AER	2 June 2014
Published regulatory proposal and supporting documents	20 June 2014
AER public forum	10 July 2014
Stakeholder submissions on regulatory proposal close	8 August 2014
AER issues draft decision	30 November 2014
Essential Energy submits revised regulatory proposal	20 January 2015
Stakeholder submissions on revised regulatory proposal close	13 February 2015
AER issues final decision	30 April 2015

133 NER, cl. 6.10.3.
134 NER, cl. 6.10.3(a), 11.56.4(o).
135 NER, cl. 6.10.2(a) and (b).
136 NER, cl. 6.10.2(c), 11.56.4(o).
137 NER, cl. 6.11.1.

Appendix A – Constituent decisions

Our draft distribution determination is predicated on the following decisions (constituent decision):[138]

Constituent decision
In accordance with clause 6.12.1(1) of the NER, the following classification of services will apply to Essential Energy for the 2015–19 regulatory control period (listed by service group): ▪ Standard control services include network services, augmentation of the network, type 5 and 6 unrecovered meter cost and type 7 metering services ▪ Alternative control services include metering types 5 and 6 provision, maintenance, reading, data services and transfer administration services, ancillary network services and public lighting ▪ Unregulated services includes type 1 to 4 metering services, metering types 5 and 6 installation services, network premises connections, network extensions.
In accordance with clause 6.12.1(2)(i) of the NER, the AER does not approve the annual revenue requirement set out in Essential Energy's building block proposal. Our draft decision on Essential Energy's annual revenue requirement for each year of the 2014–19 period is set out in attachment 1 of the draft decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER approves Essential Energy's proposal that the subsequent regulatory control period will commence on 1 July 2015. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER approves Essential Energy's proposal that the length of the subsequent regulatory control period will be four years from 1 July 2015 to 30 June 2019. This is discussed in attachment 1 of the draft decision.
In accordance with clause 6.12.1(3)(ii) and acting in accordance with clause 6.5.7(c), the AER does not accept Essential Energy's proposed total forecast capital expenditure of $2,618.7 million ($2013–14). Our substitute estimate of Essential Energy's total forecast capex for the 2015–19 period is $1934.3 million ($2013–14). This is discussed in attachment 6 of the draft decision.
In accordance with clause 6.12.1(4)(ii) and acting in accordance with clause 6.5.6(d), the AER does not accept Essential Energy's proposed total forecast operating expenditure of $2516.2 million ($2013–14). Our substitute estimate of Essential Energy's total forecast opex for the 2015–19 period is $1552.1 million ($2013–14). This is discussed in attachment 7 of the draft decision.
Essential Energy did not include any proposed contingent projects in its regulatory proposal for the 2015–19 regulatory control period. Therefore: ▪ in accordance with clause 6.12.1(4A)(i) the AER determines that there are no contingent projects for the purposes of the distribution determination ▪ in accordance with clause 6.12.1(4A)(ii), the AER has not made an assessment of whether the capital expenditure proposed in the context of each contingent project reflects the capital expenditure criteria and factors ▪ in accordance with clause 6.12.1(4A)(iii), the AER does not specify any trigger events in relation to contingent projects ▪ in accordance with clause 6.12.1(4A)(iv), the AER does not determine that any proposed contingent project is not a contingent project.
▪ In accordance with clause 6.12.1(5) the AER's decision on the allowed rate of return for the first regulatory year of the regulatory control period in accordance with clause 6.5.2 is not to accept Essential Energy's proposal of 8.83 per cent. Our decision on the allowed rate of return for the first regulatory year of the regulatory control period is 7.15 per cent as set out

[138] NER, cl. 6.12.1.

Constituent decision
in Table 1 of Attachment 3 of the draft decision. This rate of return will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
In accordance with clause 6.12.1(5A) the AER's decision is that the return on debt is to be estimated using a methodology referred to in clause 6.5.2(i)(2) which is set out in attachment 3 of the draft decision.
In accordance with clause 6.12.1(5B) the AER's decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.4. This is set out in f attachment 4 of the draft decision.
In accordance with clause 6.12.1(6) the AER's decision on the regulatory asset base as at 1 July 2014 in accordance with clause 6.5.1 and schedule 6.2 is $6,685.4 million at 1 July 2014 for its distribution network. This is set out in attachment 2 of the draft decision.
In accordance with clause 6.12.1(7) the AER does not accept Essential Energy's proposed corporate income tax of $382.7 million ($ nominal). Our decision on Essential Energy's corporate income tax is $217.9 million ($ nominal). This is set out in attachment 8 of the draft decision.
In accordance with clause 6.12.1(8) the AER's decision is not to approve the depreciation schedules submitted by Essential Energy. This is set out in attachment 5 of the draft decision.
In accordance with clause 6.12.1(9) the AER makes the following decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), service target performance incentive scheme (STPIS), demand management and embedded generation connection incentive scheme or small-scale incentive scheme are to apply: ▪ In accordance with clause 6.12.1(9) of the NER, the AER's decision is that no Essential Energy operating expenditure will be subject to the EBSS in the 2015–19 regulatory control period. ▪ In accordance with clause 6.12.1(9) of the NER, the AER will apply the CESS as set out in version 1 of the capital expenditure incentives guideline to Essential Energy in the 2015–19 regulatory control period. ▪ In accordance with clause 6.12.1(9) of the NER, the AER's *Electricity distribution network service providers, Service target performance incentive scheme, November 2009* will apply to Essential Energy in the 2015-19 regulatory control period. The AER will apply the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI) reliability of supply parameters. The AER will also apply the telephone answering parameter. As Essential Energy must comply with the existing NSW jurisdictional Guaranteed Service Level (GSL) scheme, the STPIS GSL scheme will not apply to Essential Energy. A beta of 2.5 will be used to calculate the major event day boundary. The AER's determinations on the SAIDI and SAIFI targets to apply to Essential Energy in the 2015-19 regulatory control period are set out in Tables 11.1 and 11.2, respectively, of Attachment 11 of the draft decision. The AER will apply the telephone answering parameter to Essential Energy. The performance target for answering calls within 30 seconds is 75 per cent. Consistent with clause 5.3.2(a)(1) of the STPIS, an incentive rate of -0.04 per cent per unit will apply to Essential Energy's telephone answering parameter. The revenue at risk will be capped at ±2.5 per cent. Within this there will be a cap of ±0.25 per cent on the telephone answering parameter for performance. The value of S_t for 2015–16 and 2016–17 regulatory years shall be zero. The value for S_t from 2017–18 onwards shall be calculated in accordance with Appendix C of the AER's *Service target performance incentive scheme, November 2009*. Note: The meaning for year “t” under the price control formula for this determination is different to that in Appendix C of STPIS. Year “t+1” in Appendix C of STPIS is equivalent to year “t” in the price control formula of this determination.

Constituent decision

- The AER has determined to continue Part A of the Demand Management Innovation Allowance (DMIA) but will not apply either Part B of the DMIA or the D-factor scheme for Essential Energy in the 2015–19 regulatory control period.
- In accordance with clause 6.12.1(9) of the NER, the AER's decision is that no small-scale incentive scheme is to apply to Essential Energy in the 2015–19 regulatory control period.

In accordance with clause 6.12.1(10) the AER's decision is that all appropriate amounts, values and inputs are as set out in this determination including attachments.

In accordance with clause 6.12.1(11) the AER's decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for Essential Energy for any given regulatory year is the annual revenue requirement (ARR) for distribution services for that regulatory year calculated using the formula in attachment 14 of the draft decision plus any adjustment required to move the distribution use of system (DUoS) under/over account to zero. This is discussed at attachment 14 of the draft decision.

In accordance with clause 6.12.1(12) the AER's decision on the form of the control mechanism for alternative control services is to apply price caps. This is discussed in attachment 14 of the draft decision.

In accordance with clause 6.12.1(13), the AER's decision is Essential Energy, to demonstrate compliance with its distribution determination, must maintain a DUoS unders and overs account. Essential Energy must provide information on this account to the AER in its annual pricing proposal.

In accordance with clause 6.12.1(14), the AER's decision on the additional pass through events that are to apply is not to accept the nominated pass through events as drafted by Essential Energy. The AER substitutes its own definitions for the following events:

- insurance cap event
- terrorism event
- natural disaster event.

This is set out in attachment 15 of the draft decision.

In accordance with clause 6.12.1(15), the AER's decision is to approve Essential Energy's proposed negotiating framework. The negotiating framework that is to apply to Essential Energy is set out at attachment 17 of the draft decision.

In accordance with clause 6.12.1(16), the AER's decision is to apply the negotiated distribution services criteria published in June 2014 to Essential Energy. This is set out in attachment 17 of the draft decision.

In accordance with clause 6.12.1(17), the AER's decision on the procedures for assigning retail customers to tariff classes is not to accept Essential Energy's proposed procedure. The AER's decision on the procedures for assigning retail customers to tariff classes is set out at attachment 14 of the draft decision.

In accordance with clause 6.12.1(18), the AER's decision on regulatory depreciation is that the forecast depreciation approach is to be used to establish the RAB at the commencement of Essential Energy's regulatory control period (1 July 2019). This is discussed in Attachment 2 of the draft decision.

In accordance with clause 6.12.1(19) the AER's decision on how Essential Energy is to report to the AER on its recovery of designated pricing proposal charges is Essential Energy is to set these out in its annual pricing proposal. The AER accepts Essential Energy's proposed methodology however does not accept the adjustments to be made to subsequent pricing proposals to account for under and over recovery of charges. This is discussed in attachment 14 of the draft decision.

Constituent decision
In accordance with clause 6.12.1(20), the AER's decision is to require Essential Energy to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to the AER in its annual pricing proposal as set out in attachment 14 of the draft decision.
In accordance with clause 6.12.1(21), the AER approves the connection policy as proposed by Essential Energy in its regulatory proposal. This is set out in attachment 18 of the draft decision.

Appendix B – Arrangements for transitional period

New rules

In November 2012, the Australian Energy Market Commission (AEMC) introduced major changes to the economic regulation of DNSPs under chapter 6 of the NER (the new rules).[139]

Prior to the making of the new rules, distribution determinations for the NSW/ACT DNSPs were due to commence on 1 July 2014 and would apply for a period of five years. However, the process was delayed so the new rules could be applied to the NSW/ACT DNSPs.

To allow for an expedited transition to the new rules, the AEMC made transitional rules in chapter 11 of the NER under which there would be two regulatory control periods to cover the following period:[140]

- a regulatory control period covering the period 1 July 2014 to 30 June 2015, referred to in the NER as 'the transitional regulatory control period', and
- a regulatory control period covering the period from 1 July 2015 to 30 June 2019 referred to in the NER as 'the subsequent regulatory control period'.[141]

The two periods are separate and distinct,[142] however, our decisions concerning these two periods interact in important ways. This appendix explains why and how.

The transitional determination

For the transitional regulatory control period, we made a fast-tracked placeholder determination on 16 April 2014 for each of the NSW/ACT service providers. It was made following an abbreviated consultation period and was intended to act as a temporary placeholder for 2014–15 to allow for an expedited transition to the new rules.

In a typical distribution determination we make many constituent decisions about the efficient costs of a service provider. In the placeholder determination these constituent decisions were not subject to our usual detailed assessment. Some of the decisions in our placeholder determination therefore maintained the status quo that had been operating during the previous regulatory control period of 2009–14. For instance, the NER stipulated that although new regulations had introduced a capital efficiency sharing scheme, no new capital efficiency sharing scheme should apply during the transitional regulatory control period. Similarly, any pass through events that had applied during the 2009–14 regulatory control period should continue to apply during the 2014–15 transitional year. Maintaining the status quo in this way was intended to facilitate making a place holder determination in the short period of time available to allow the transition to the full operation of the rules for the 2015–19 regulatory control period.

In relation to some decisions for the transitional year, however, it was appropriate that these changes take effect immediately. For instance, changes to the way electricity services should be classified took effect from the start of the transitional year. We had already conducted extensive discussions with interested stakeholders during our framework and assessment approach process that we conducted

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139 AEMC Final Rule Determination, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012*, 29 November 2012 (AEMC Final Rule Determination).

140 NER, cl.11.55.1 defines 'transitional regulatory control period' and 'subsequent regulatory control period' Cl. 11.56 outlines the requirements of a transitional regulatory proposal and cl.11.56.4 the subsequent regulatory control period

141 NER, cl.11.55.1 definitions.

142 NER, cl. 11.56.4(g).

during 2012–13 and there was no reason to delay the introduction of these changes that were beneficial to the community.

Our most complex, and arguably most important, task when we make a distribution determination is to determine the revenues that a service provider may recover each year through its network charges. For the transitional year, the NER transitional rules introduced a fast-tracked approach to assessing the expected revenues for that year. Rather than make a detailed assessment of required revenue for the transitional year, we conducted a high level assessment of the key inputs used by the service providers to develop their proposed revenues. We were not satisfied with the proposed revenues for the transitional year and instead determined an alternative annual revenue requirement by adjusting a limited number of inputs to the service providers' proposals, specifically, the rate of return and value of imputation credits (gamma). We approved this estimate for each service provider as a placeholder revenue allowance that would later be 'trued-up' in our determination for the 2015–19 regulatory control period. That is, the difference between the notional revenue approved for 2014–15 under this full determination process and the placeholder revenue would be adjusted for in net present value terms over the annual revenue requirements determined for the 2015–19 regulatory control period.

The full distribution determination for 2014–19

Our determination for the 2015–19 regulatory control period is a full determination made under the new rules.

When making our determination of revenues for this period, we are required to determine the notional annual revenue requirement for each year of the 2014–19 period (that is, including the 2014–15 transitional year). The unsmoothed notional annual revenue requirements could be quite different between the amounts submitted for the transitional proposal process and for this full proposal process.

However, when determining the expected revenues we will permit a service provider to recover through its charges, we smooth the annual revenue requirements. Because the 2014–15 annual revenue requirement was already determined by the placeholder decision (and charges have already been set using these expected revenues), this smoothing accounts for the placeholder revenue for the transitional year when determining the expected revenues for the four years of the 2015–19 regulatory control period. This process provides a 'true-up' or 'adjustment' for any difference between the placeholder revenue for the transitional year and our subsequent determination of the annual revenue requirement for that year, and a general process of smoothing over the 2015–19 regulatory control period.

The effect of this approach is that the total allowed revenue we approve over the five years from 2014–19 is calculated under the new rules. In this way the two regulatory control periods are linked. For the purpose of smoothing revenues, the two regulatory control periods are treated as if they had just been one period. For legal purposes generally, however, the two periods remain separate and distinct regulatory control periods[143].

In this determination, we have sought to reflect the transitional arrangements in the following manner:

- When we need to refer to the 5 years across the period from 2014–19, we use the phrase '2014–19 period'.

[143] NER, cl. 11.56.5(g).

- When we need to distinguish 2014–15 from the 2014–19 period, we refer to it as the transitional year.
- When we refer to the regulatory control period, we use the phrase '2015–19 regulatory control period'.

Implementing the true-up

As part of our full determination of notional revenues for the 2014–19 period, we have determined further changes to the rate of return and gamma, and reductions to other costs such as capex and opex. The placeholder revenue for 2014–15 reflects changes to the rate of return and gamma only. These further changes mean that the 2014–15 placeholder revenue was too high. A true-up therefore needs to occur.[144]

The true-up can be measured as the difference between the placeholder revenue for 2014–15 and the notional annual revenue requirement for 2014–15 determined by the AER in this draft decision. Table B-1 shows how the true-up amount is determined and that $338.9 million will be returned to customers over the 2015–19 regulatory control period (adjusted for the time value of money).

Table B-1 True-up for Essential Energy ($ million, nominal)

Essential Energy	2014–15
AER draft decision – notional annual revenue requirement	952.9
AER transitional decision – placeholder revenue	1291.7
Difference	–338.9

[144] The size of the true-up reflects not only further reductions in costs from the transitional decision but also any difference in the smoothing profile of revenues that occurred between that transitional decision and this draft decision.

Appendix C – Better Regulation Guidelines

The guidelines which we applied in assessing Essential Energy's regulatory proposal are summarised below.

Forecasting efficient expenditure

Our Better Regulation expenditure forecast assessment guideline sets out how we assess a business' revenue proposal and how we determine a substitute forecast when required. Businesses must provide economic analysis to justify the efficiency and prudency of their expenditure proposals. In the absence of economic justification we are unlikely to accept their forecast expenditure.

Our general approach is to assess the efficiency of a network business and determine whether previous spending is an appropriate starting point. If there is evidence of inefficiency we will use benchmarks that reflect efficient costs.

To assess a business's revenue proposal, we apply a range of techniques that typically involve comparing the proposal to estimates we develop from relevant information sources. Where these techniques indicate the expenditures are not efficient, we will set our own efficient forecast. These techniques include:

- economic benchmarking—productivity measures used to assess a business's efficiency overall
- category level analysis—comparing how well a business delivers services for a range of individual activities and functions, including over time and with its peers
- predictive modelling—statistical analysis to predict future spending needs, currently used to assess the need for upgrades or replacement as demand changes (augmentation capex, or augex) and expenditure needed to replace aging assets (replacement capex, or repex)
- trend analysis—forecasting future expenditure based on historical information, particularly useful for opex where spending is largely recurrent and predictable
- cost benefit analysis—assessing whether the business has chosen spending options that reflect the best value for money
- project review—a detailed engineering examination of specific proposed projects or programs
- methodology review—examining processes, assumptions, inputs and models that the business used to develop its proposal
- governance and policy review—examining the business's strategic planning, risk management, asset management and prioritisation.

The expenditure assessment guideline also sets out our principles for guiding our reliance on assessment techniques and a business forecasting approach. These include validity, accuracy and reliability, parsimony, robustness, transparency and fitness for purpose.

In the remainder of this section we explain how as part of our determinations we also calculate the rewards and penalties for past performance under our expenditure incentive schemes. In addition, how we combine our approach to incentives with our forecasting approach to ensure consumers will pay no more than necessary for a safe and reliable energy supply.

Forecasting and reviewing capital expenditure

During a determination we assess the business' past capex spending and future capex needs. We:

- assess the business' proposed forecast of the total capex it needs to spend over the next period
- update the business' RAB to include the capex it spent in the past during the period, excluding any inefficient capex overspend
- calculate the rewards and penalties the business will receive under the capital expenditure sharing scheme (CESS) for capex underspends or overspends it incurred during the period.

We assess the business' total capex forecast by considering the efficiency of the proposed expenditure. Our assessment of the total forecast capex can be informed by indicators of overall network performance and risk. We utilise a range of tools to inform that consideration. We have developed a new tool to better forecast the expenditure needed to build, upgrade or replace network assets to address changes in demand (augmentation capex, or augex). This complements our existing tool that examines the expenditure needed to replace aging assets (replacement capex, or repex). We also consider capex forecasts associated with connections and other customer driven work, non-network capex (for example IT equipment) and the capitalisation of overhead costs.

We will use our capex forecasting techniques to review what the business spent on capex during the period. The capital expenditure incentives guideline sets out our staged process for this ex post review. If a business' capex exceeds what was forecast, we will examine their spending. If we determine all or some of the overspending was inefficient, the business may not be allowed to add the excess spending to its RAB.[145]

The CESS rewards or penalties apply automatically to capex underspends or overspends. However, we may adjust the CESS payments to account for:

- Our ex post review—if the business has overspent and we decide under the ex post review to exclude all or some of the overspend from the RAB we will adjust the CESS payments. Otherwise a business could bear more than 100 per cent of the cost of the excluded capex.
- Capex deferrals—a business may have decided to spend capex at a later time than it had previously planned. We refer to this as capex deferral, and a business may defer capex from one regulatory period into the next. We will adjust the CESS payments where a material proportion of capex is deferred. This means consumers will share in the benefits where material amounts of capex are deferred from one regulatory control period to the next. This also helps deter businesses from deferring capex between regulatory control periods unless it is efficient to do so. When assessing forecast capex we will also consider deferrals and the rewards or penalties under the CESS.

Forecasting and reviewing operating expenditure

During a determination we assess the business' past opex spending and future opex needs. We:

- assess the business' proposed forecast of the total opex it needs to spend over the next period

[145] We cannot exclude inefficient capex overspends if a business spent the capex prior to 2014, but this timing differs slightly for different businesses.

- calculate the rewards and penalties (carryover amounts) the business will receive under the EBSS for opex performance during the period.

We forecast opex using the approach outlined in our Expenditure Forecast Assessment Guideline. Under this approach opex is based on an efficient amount of actual expenditure in a single year (known as 'base opex'), which is multiplied by a forecast rate of change for each year of the forecast period. We then add any step changes for efficient costs that are not captured by the base opex or the rate of change.

We prefer to asses base opex using the service providers revealed expenditure in a single year. If revealed expenditure in the base year reasonably reflects the opex criteria, we will set base opex equal to that revealed expenditure. We use a combination of techniques to assess whether base opex is efficient. If we find base opex to be materially inefficient, we either adjust the base year or substitute an appropriate base year. When determining whether to adjust or substitute base year expenditure, we have regard to whether rewards or penalties accrued under the EBSS will fairly share efficiency gains or losses between the service provider and its customers.

We then apply an annual rate of change to base opex to forecast opex for each year of the forecast regulatory control period. The rate of change captures changes in forecast:

- output
- prices
- productivity.

We then add or subtract step changes for any other expenditure not captured in base opex or the rate of change that is required for forecast opex to meet the opex criteria. Step changes should not double count cost included in other elements of the opex forecast: If it is efficient to substitute capex with opex, a step change may be included for these costs (capex/opex trade-offs).

Determining the allowed rate of return

The allowed rate of return is the forecast of the cost of funds a network business requires to attract investment in the network. To estimate this cost, we consider the cost of the two sources of funds for investments—equity and debt. The return on equity is the return shareholders of the business will require for them to continue to invest. The return on debt is the interest rate the network business pays when it borrows money to invest. We consider that efficient network businesses would fund their investments by borrowing 60 per cent of the required funds, while raising the remaining 40 per cent from equity.

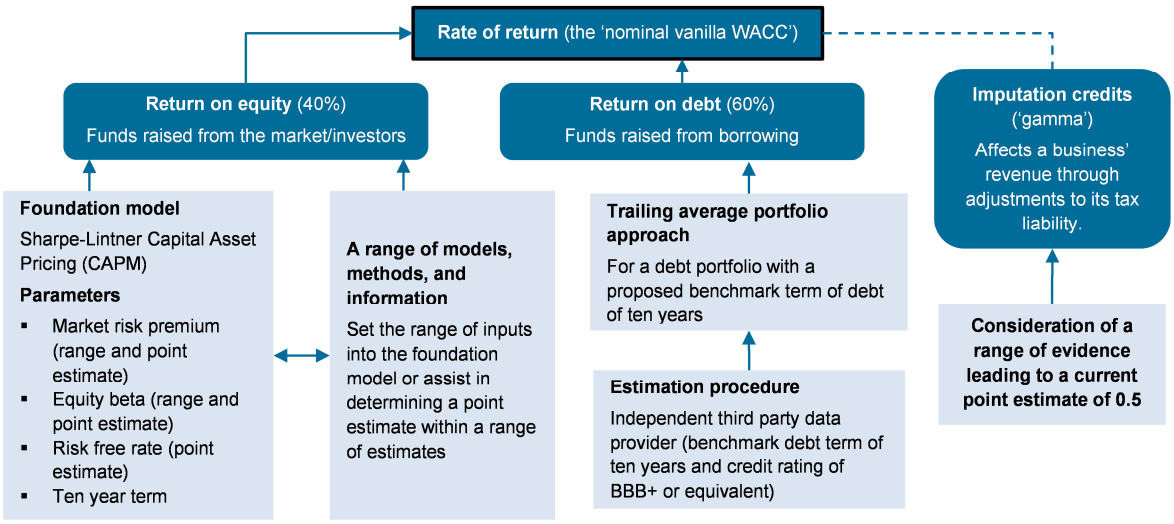
A good estimate of the rate of return is necessary to promote efficient prices in the long term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. On the flip side, if the rate of return of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high prices.

The return on investment can make up approximately 50 per cent of revenue needs for network businesses. Our aim is to set a rate of return that delivers sufficient but not excessive returns to support investment in safe and reliable energy networks. The value of the business' capex investments in its RAB is multiplied by the allowed rate of return to determine the total return on

capital the network business can charge energy consumers. So we also aim to set a rate of return that enables business to make efficient choices between capex and opex.

The estimation method set out in our rate of return guideline is shown in Figure C-1.

Figure C-1 Better Regulation rate of return guideline estimation method overview



The benchmark efficient business

We estimate the returns on equity and debt for a benchmark efficient business. This approach supports the rate of return objective in the rules—for the overall rate of return to correspond to the efficient financing costs of a benchmark efficient business. By setting a rate of return based on a benchmark, rather than the actual costs of individual businesses, network businesses have incentives to finance their business as efficiently as possible.

We define the benchmark efficient business as one who only provides regulated electricity or gas network services, operating within Australia. This applies to both electricity and gas as the risks across both industries are sufficiently similar such that a single benchmark is appropriate.

Return on equity

Our approach to the return on equity balances providing predictability for investors and consumers while incorporating the latest market data. Recognising there is not one perfect model to estimate the return on equity, our approach draws on a variety of models and information.

Our starting point is the standard Capital Asset Pricing model (CAPM)—our 'foundation model.' We then use a range of models, methods, and information to inform our return on equity estimate. We use this information to either set the range of inputs into the CAPM foundation model or assist in determining a point estimate within a range of estimates at the overall return on equity level.

Return on debt

Our approach to the return on debt closely aligns with the efficient debt financing practices of regulated businesses. Our approach is to consider the average interest rate that a network business would face if it raised debt annually in ten equal parcels. This is referred to as the trailing average portfolio approach. This approach assumes that every year, one-tenth of the debt of a network

business is re-financed. As the return on debt is an average of the interest rates over a period of ten years, this approach leads to a relatively stable estimate over time.

Shared asset guideline

The shared asset guideline sets out our approach to sharing the benefits with consumers when a network business is paid for providing unregulated services. We will reduce the amount that business can recover from electricity consumers to reflect the unregulated revenues.

Network businesses have the opportunity to propose alternative approaches. However, we will be unlikely to accept alternatives if they leave consumers worse off than under our approach in the guideline.

The guideline sets out how we reduce consumer costs for shared assets:

- Materiality: we will take action when the unregulated revenues from shared assets are more than 1 per cent of a service provider's total annual revenue
- Method: we will reduce a service provider's regulated revenues by around 10% of the value of unregulated revenues earned from shared assets
- Information reporting: what we'll require from service providers to determine shared asset cost reductions.

Our shared asset mechanism forecasts the annual unregulated revenue that a network business is expected to earn from shared assets.

This forecast is then compared to the revenue that is required to provide regulated services. If the total unregulated revenue is expected to be greater than 1 per cent of the regulated revenue, we'll apply a cost reduction.

This clear and transparent materiality threshold balances administrative effort with potential consumer benefits.

The cost reduction will reduce a network business' regulated revenue by 10 per cent of the value of its expected total unregulated revenues from shared assets in that year. This reduces the amount to be recovered from consumers and consequently electricity prices.

The potential value of the cost reduction is capped by the electricity rules, so that the reduction cannot exceed the regulated revenue from those assets.

Consumer engagement guideline for network service providers

The consumer engagement guideline for network service providers sets out a framework for electricity and gas service providers to better engage with consumers. The guideline aims to help these businesses develop strategies to engage systematically, consistently and strategically with consumers on issues that are significant to both parties.

We expect each service provider to develop consumer engagement approaches and strategies that address the best practice principles and the four components of the guideline that are explained over the page.

Implementing the guideline will help service providers demonstrate how their spending proposals contribute to the objectives contained in the national electricity and gas laws. That is, that their spending proposals promote efficient investment in, and efficient operation and use of, energy services for the long term interests of energy consumers.

Service providers must describe how they have engaged with consumers, and how they have sought to address any relevant concerns identified as a result of that engagement. Service providers present this information in an overview report to their regulatory or revenue proposals.

Underpinning the guideline are four best practice principles. They overarch all aspects of consumer engagement, so service providers should use these principles in undertaking each component of the guideline:

- Clear, accurate and timely communication—we expect service providers to provide information to consumers that is clear, accurate, relevant and timely, recognising the different communication needs and wants of consumers.
- Accessible and inclusive—we expect service providers to recognise, understand and involve consumers early and throughout the business activity or expenditure process.
- Transparent—we expect service providers to clearly identify and explain the role of consumers in the engagement process, and to consult with consumers on information and feedback processes.
- Measurable—we expect service providers to measure the success, or otherwise, of their engagement activities.

The guideline is structured around four components. The components set out a process for service providers to develop and implement new or improved consumer engagement activities to meet the best practice principles:

- Priorities—we expect service providers to identify consumer cohorts, and the current views of those cohorts and their service provider; outline their engagement objectives; and discuss the processes to best achieve those objectives.
- Delivery—we expect service providers to address the identified priorities via robust and thorough consumer engagement.
- Results—we expect service providers to articulate the outcomes of their consumer engagement processes and how they measure the success of those processes reporting back to us, their business and consumers
- Evaluation and review—we expect service providers to periodically evaluate and review the effectiveness of their consumer engagement processes.

Appendix D – Material issues and opportunity to be heard

Engagement, consultation and consultants

In considering Essential Energy's proposal and in reaching our draft decision, we undertook a range of processes to inform interested parties of material issues under consideration and provided reasonable opportunities to be heard.

Consumer Challenge Panel

The newly formed Consumer Challenge Panel (CCP) played a significant role in our processes of assessing the proposal before us. The panel advised us on issues that are important to consumers and provided consumer perspectives, particularly those of residential and small business consumers. Members of the panel bring with them experience in regulation, networks, economics, finance and consumer engagement.[146]

The purpose of the CCP is to assist us to make better regulatory determinations by providing input on issues of importance to consumers. Regulatory determinations are technical and complex processes which can make it difficult for ordinary consumers to participate. The expert members of the CCP bring consumer perspectives to us to better balance the range of views we consider as part of our decisions.

The role of CCP members includes:

- advising us on whether a distributor's proposal is justified in terms of the services to be delivered to customers; whether those services are acceptable to, and valued by, customers; and whether the proposal is in the long term interests of consumers
- advising us on the effectiveness of distributor's engagement with its customers and how this engagement has informed, and been reflected in, the development of its proposal.

The CCP provided advice on Essential Energy's regulatory proposal which was published on our website.[147] We address the detail of the CCP's submission in conducted our detailed analysis (see attachments).

In short, the CCP does not support Essential Energy's regulatory proposal as being in the long term interests of consumers.[148]

Stakeholder views

We have been engaging with stakeholders over an extended period of time in the lead up to Essential Energy submitting its regulatory proposal in June 2014. We commenced engagement on the

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146 AER, *Statement of intent 2014–15 to COAG Energy Council*, 2014, p. 5. CCP members involved in the NSW resets are Ms Jo DeSilva, Mr Mark Henley, Ms Ruth Lavery, Mr Bruce Mountain and Dr Gill Owen. Member biographies and information on the CCP is available at http://www.aer.gov.au/node/19305.

147 CCP advice is available at http://www.aer.gov.au/node/11483.

148 CCP1, *Submission to the AER - Jam tomorrow?,* August 2014, p. 2.

framework and approach in February 2012 and engagement has continued since then both on a formal and informal basis.[149]

We are therefore able to draw on comments and submissions from earlier consultative processes in addition to the submissions received in response to Essential Energy's regulatory proposal.

In response to Essential Energy's regulatory proposal, we received 50 submissions.[150] Appendix E lists all submissions received. We received submissions across a broad range of stakeholder groups, including:

- retailers
- major energy users
- local councils
- private metering businesses
- agricultural groups
- public interest advocacy groups
- ethnic Communities Council
- social services groups
- environmental and clean energy groups
- consumer Challenge Panel
- Networks NSW

Engagement with Essential Energy

We regularly engaged with Essential Energy both before and during the review. Similar to our stakeholder engagement, we commenced consultation with Essential Energy in October 2011. Since that time, we have met with Essential Energy and the other NSW distributors at a staff level on a monthly basis. The purpose of these meetings is for all parties to provide updates and seek information and clarification on issues relevant to the 2014–19 period.

Consultants

We commissioned the following independent consultants for our draft decision:

- Deloitte Access Economics, for advice on forecast growth in labour costs
- Energy Market Consulting associates (EMCa), for advice on technical aspects of Essential Energy's past and forecast expenditure (capex/opex)
- Dennis Lawrence for advice on benchmarking
- Associate Professor John Handley, for advice on rate of return

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149 Information on our formal stakeholder engagement, including meeting agendas, attendee sheets and presentation material can be found at http://www.aer.gov.au/node/24556 and select NSW.

150 All submissions are available at http://www.aer.gov.au/node/11483.

- Marsden Jacob, for review of unit costs

We engaged these consultants to help us determine whether technical aspects of Essential Energy's proposal are reasonable. The consultants' advice also helps us develop our substitute expenditure forecast (if required). While we seek the consultants' advice and expertise to help understand the proposal from a technical perspective, we are not bound to use the consultants' forecast or adjustments as a replacement. We use judgment in adopting their advice and consider a broader array of interconnecting information including engineering, economic and legal matters.

Internal experts

We also boosted our internal expertise by appointing four in-house technical advisors to provide us with greater industry expertise, particularly in power system engineering. The new technical advisor group was established in late October 2013. They bring significant technical knowledge and electricity industry experience to the AER.

The technical advisors complement the internal expertise we have already developed. They have improved our use of external consultants and helped implement new regulatory approaches developed under the Better Regulation program. Our staff are also assisted by the ACCC/AER Regulatory Economic Unit (REU). REU comprises seven specialist economists who provide advice to the ACCC's regulatory areas, including the AER whose staffing and support is provided by the ACCC. Six of the seven REU economists have PhDs in economics and related fields.

Appendix E – List of submissions

We received 50 submissions in response to Essential Energy's regulatory proposal as listed below:

	Submission from	Date received	Submission on
1	Energy Australia	08/08/2014	NSW DNSPs
2	Energy Retailers Association of Australia (ERAA)	08/08/2014	NSW DNSPs
3	AGL	08/08/2014	NSW DNSPs
4	EnerNOC Pty Ltd	08/08/2014	NSW DNSPs
5	Clean Energy Council (CEC)	08/08/2014	NSW DNSPs
6	Networks NSW	08/08/2014	NSW DNSPs
7	Energy Markets Reform Forum (EMRF) – EMRF is an affiliate of Major Energy Users Inc. (MEU)	08/08/2014	NSW DNSPs
8	Energy Users Association of Australia (EUAA)	10/08/2014	NSW DNSPs
9	PIAC	08/08/2014	NSW DNSPs
10	Vector Limited	08/08/2014	NSW DNSPs
11	EUAA	08/08/2014	NSW DNSPs
12	Ethnic Communities' Council of NSW (ECC)	07/08/2014	NSW DNSPs
13	Council of Social Service of NSW (NCOSS)	07/08/2014	NSW DNSPs
14	National Generators Forum	01/07/2014	NSW DNSPs
15	Origin Energy	08/08/2014	NSW DNSPs
16	CCP1	12/08/2014	NSW DNSPs
17	Simply Energy	14/08/2014	NSW DNSPs
18	Total Environment Centre	14/08/2014	NSW DNSPs
19	UnitingCare Australia	03/09/2014	NSWDNSPs
20	NSW Irrigators' Council (NSWIC)	06/08/2014	Essential Energy

	Submission from	Date received	Submission on
21	Cotton Australia	10/07/2014	Essential Energy
22	South East Regional Organisation of Councils (SEROC)	11/08/2014	Essential Energy
23	Lachlan Shire Council	08/08/2014	Essential energy
24	Riverina and Murray Regional Organisation of Councils (RAMROC)	10/8/2014	Essential Energy
25	Byron Shire Council	10/08/2014	Essential Energy
26	Berrigan Shire Council	08/08/2014	Essential Energy
27	Kempsey Shire Council (Mid North Coast Regional Organisation of Councils - MIDROC)	08/08/2014	Essential Energy
28	Warringah Council	08/08/2014	Essential Energy
29	Lismore City Council	08/08/2014	Essential Energy
30	Tweed Shire Council	08/08/2014	Essential Energy
31	Urana Shire Council	08/08/2014	Essential Energy
32	Temora Shire Council	08/08/2014	Essential Energy
33	Northern Rivers Regional Organisation of Councils (NOROC)	08/08/2014	Essential Energy
34	Orana Regional Organisation of Councils (OROC)	08/08/2014	Essential Energy
35	Kyogle Council	08/08/2014	Essential Energy
36	Harden Shire Council	08/08/2014	Essential Energy
37	Eurobodalla Shire Council	08/08/2014	Essential Energy
38	Forbes Shire Council	08/08/2014	Essential Energy
39	Central NSW Councils (Centroc)	08/08/2014	Essential Energy
40	Richmond Valley Council	07/08/2014	Essential Energy
41	Bathurst Regional Council	07/08/2014	Essential Energy

	Submission from	Date received	Submission on
42	Energy & Management Services (for NSW Local Councils)	07/08/2014	Essential Energy
43	Energy & Management Services (for rural councils in NSW)	07/08/2014	Essential Energy
44	Narromine Shire Council	06/08/2014	Essential Energy
45	Goulburn Mulwaree Council	05/08/2014	Essential Energy
46	Riverina and Murray Regional Organisation of Councils (RAMROC)	08/08/2014	Essential Energy
47	South East Regional Organisation of Councils (SEROC)	11/08/2014	Essential Energy
48	Corowa Shire Council	30/07/2014	Essential Energy
49	Leeton Shire Council	4/08/2014	Essential Energy
50	Upper Lachlan Shire Council	08/08/2014	Essential Energy