



**Issues paper**  
**Qld electricity distribution regulatory**  
**proposals**  
**2015–16 to 2019–20**

December 2014

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AER reference: 54678/54677 D14/160571

## Request for submissions

Interested parties are invited to make written submissions regarding the distributors' regulatory proposals to us, the Australian Energy Regulator (AER), by the close of business, **30 January 2015**.

We prefer that all submissions sent in an electronic format are in Microsoft Word or other text readable document form. Submissions should be sent electronically to:

- [QLDelectricity2015@aer.gov.au](mailto:QLDelectricity2015@aer.gov.au) for either or both of Energex and Ergon Energy.

Alternatively, submissions can be sent to:

Mr Sebastian Roberts  
General Manager  
Australian Energy Regulator  
GPO Box 520  
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We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information are requested to:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non-confidential version of the submission in a form suitable for publication.

All non-confidential submissions will be placed on our website at [www.aer.gov.au](http://www.aer.gov.au). For further information regarding our use and disclosure of information provided to us, see the ACCC/AER Information Policy, October 2008 available on our website.

Enquires about this paper, or about lodging submissions, should be directed to our Network Opex and Coordination branch on (07) 3835 4669.

### Next steps

We will consider and respond to submissions on this issues paper in the context of our regulatory determinations. We expect to publish our preliminary decision in April 2015.

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## Shortened forms

Shortened form	Extended form
ACCC	Australian Competition & Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CCP	consumer challenge panel
CPI	consumer price index
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
NEL	National Electricity Law
NEM	National Electricity Market
NEO	national electricity objective
NER or rules	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
RIN	regulatory information notice
WACC, rate of return	weighted average cost of capital

The key terms and their shortened forms, listed above, are largely derived from the National Electricity Rules (the rules). The shortened forms used here are commonly used by us, industry participants and other stakeholders.

# 1 Introduction

Energex and Ergon Energy (the distributors) are distribution network service providers that supply electricity to almost all residences and businesses in Queensland (Qld).<sup>1</sup> Energex and Ergon Energy have submitted regulatory proposals to us. These set out the revenues they propose to collect from electricity consumers through distribution charges for the next five year period (2015–20).

Distribution charges make up around 40 per cent of a typical residential customers' final bill.<sup>2</sup> Other components include the cost of generation, transmission network charges and retailer costs. We, the Australian Energy Regulator, approve the revenues that a distribution company is allowed to recover from consumers. We will assess the proposals submitted to us by Energex and Ergon Energy. In doing so, we will work within the regulatory framework we administer. That is, we will apply the National Electricity Law (NEL) and National Electricity Rules (rules), as we are required to do. Both put the focus squarely on outcomes for electricity consumers.

Under the NEL and the rules, we must decide whether Energex and Ergon Energy's proposals represent their efficient costs. If so, we will accept them. If not, we will determine ourselves what revenues Energex and Ergon Energy will be allowed to earn over the 2015–20 period.

Whether or not the proposals should be accepted or revised is our responsibility. However, we are keen to hear the views of consumers and other stakeholders, as these will form a critical part of our assessment. This issues paper is the first step in our public consultation process. It sets out our initial impressions of the distributors' proposals, including what we think will be some of the key issues for our assessment. We hope this paper is helpful for readers to form their own views on the distributors' proposals.

We will make preliminary determinations by 30 April 2015, which will take effect at the commencement of the regulatory control period on 1 July 2015. As required by the transitional arrangements in the rules, we will then revoke the preliminary determinations and make final determinations by 31 October 2015. This means that the network prices which take effect on 1 July 2015 will be based on our preliminary determinations. Our final determinations will take effect on 1 July 2016. Any necessary corrections for the 2015–16 year will be reflected in the revenues we approve for 2016–17 and the remaining years of the regulatory period.

There have been significant changes to the regulatory framework we administer. The Australian Energy Market Commission (AEMC) finalised amendments to the rules in November 2012. These changes have resulted in a renewed emphasis on the long term interests of consumers. The appeal process relating to our network determinations was also amended so that any appeals by the distributors must demonstrate that the changes sought would leave consumers better off. The revised rules lead us to develop guidelines that set out how we propose to approach important aspects of our review.

The distributors' regulatory proposals are available on our website ([www.aer.gov.au](http://www.aer.gov.au)). The following sections of this paper highlight aspects of the distributors' regulatory proposals. This material examines the main components of the distributors' total revenue proposals—capital expenditure (capex), operating expenditure (opex) and the rate of return. Details on when and how to make submissions along with other key dates in our assessment process are set out below.

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<sup>1</sup> Energex and Ergon Energy are both wholly owned by the Qld Government.

<sup>2</sup> This proportion varies across jurisdictions.

## Your submission and key dates

It is important that your submission is, as much as possible, supported by reasons, facts and analysis. General statements made about a regulatory proposal are of limited use for our assessment. If you consider a certain aspect of the distributor's regulatory proposal is not justified, you should state why you consider it is not justified, with reference to reasons that support your views. You should also state what further information you consider the distributor should provide to justify that aspect of its proposal.

When considering the questions on which we would like feedback, it is useful to keep in mind that we must comply with the National Electricity Law (NEL) and rules.<sup>3</sup> The capital expenditure (capex) and operating expenditure (opex) forecasts of a distribution business must be aimed at meeting expected demand and all regulatory obligations as well as maintaining the safety of the network. If there are no regulatory obligations in relation to quality, reliability and security of supply, a business is to maintain existing levels. We may also take into account feedback from consumers around their service levels and the network charges they pay.

We are primarily interested in receiving submissions on the distributors' proposed approaches to opex, capex, the rate of return and consumer engagement. However, we will consider submissions on any aspect of the distributors' proposals. Key dates for our assessment process are set out in table 1 below.

**Table 1 Key dates for the Qld distribution determination process**

Task	Date
Distributor regulatory proposal submitted to AER	31 October 2014
Publish regulatory proposal and supporting documents	19 November 2014
AER public forum	9 December 2014
Stakeholder submissions on regulatory proposals close	30 January 2015
AER issues preliminary decision	30 April 2015
AER preliminary decision conference	May 2015*
Stakeholder submissions on preliminary decision close	2 July 2015
Distributors submit revised regulatory proposals	2 July 2015
Stakeholder submissions on revised regulatory proposals close	24 July 2015
AER revokes preliminary decision and issues final decision	31 October 2015

\*Note: Dates are indicative only and will be confirmed as process progresses.

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<sup>3</sup> Available at the Australian Energy Market Commission website: [www.aemc.gov.au/Energy-Rules](http://www.aemc.gov.au/Energy-Rules).



## 2 Our initial observations

Energex has proposed average annual network price increases of around 2 per cent.<sup>4</sup> Under the Qld Government's universal tariff policy, Ergon Energy's customers pay the same tariffs as customers of Energex.

In the absence of the Qld Government's Solar Bonus Scheme, the network price impacts of Energex's regulatory proposal would be lower, particularly in 2015–16. Without Solar Bonus Scheme costs, Energex's proposed network prices would be around 9 per cent lower in 2015–16 compared to 2014–15.<sup>5</sup> For reference, Ergon Energy submitted that, without Solar Bonus Scheme costs, its proposal would result in network prices around 4 per cent lower in 2015–16. We discuss the impact of the Solar Bonus Scheme in more detail in chapter 4 of this paper.

We will assess the proposals from Energex and Ergon Energy to determine whether we can accept them. We will form a view on whether they reflect the circumstances the distributors will be operating in. The circumstances have changed since we made their last determinations five years ago, including:

- the cost of infrastructure financing has fallen substantially
- less onerous network security and reliability standards
- reforms driven by the Qld Government aimed at improving network efficiency
- demand for electricity has been flat or declining.

The main components of Energex and Ergon Energy's proposed revenues are the rates of return required to finance their assets, their capex and their opex.

Energex and Ergon Energy have both proposed lower rates of return on their assets than in the 2010–15 period when they received 9.72 per cent. Energex has proposed a rate of return of 7.75 per cent and Ergon Energy 8.02 per cent.

Both distributors have also proposed lower capex and opex than they have spent in the 2010–15 period. Energex has proposed capex 33 per cent lower than its actual capex in 2010–15 and opex 5 per cent lower. Similarly, Ergon Energy proposed capex 18 per cent lower compared to 2010–15 and opex 13 per cent lower.

Despite Energex and Ergon Energy proposing lower capex than in the current period, their regulated asset bases are proposed to continue to grow over the 2015–20 period. This is because proposed capex continues to exceed asset depreciation. We will assess whether these capex proposals fully reflect the operating circumstances the distributors are likely to face over the next five years, including weak demand growth and amended reliability level requirements.

We will consider whether the opex proposals submitted by Energex and Ergon Energy reasonably represent the efficient cost of operating their networks. While Ergon Energy in particular has proposed lower opex than it spent in the current period, its current period spending has been higher than we

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<sup>4</sup> In \$nominal terms. Energex, *Regulatory proposal*, p. 12.

<sup>5</sup> Energex, *Regulatory proposal*, p. 10.

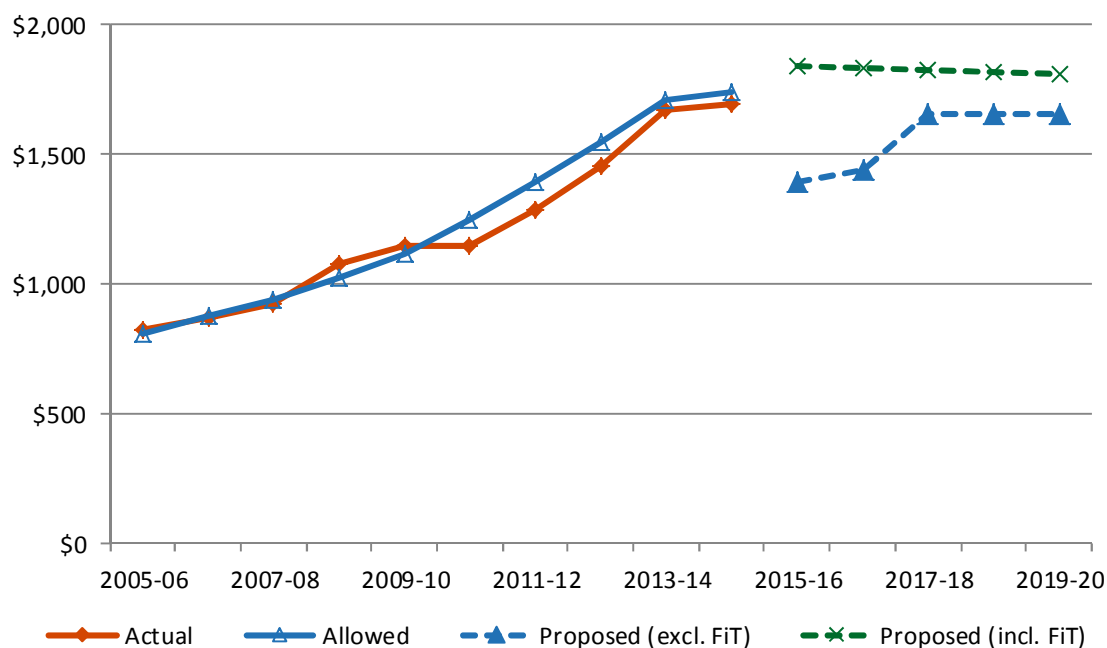
approved 5 years ago. We will assess the distributors' opex proposals against the opex criteria set out in the rules.<sup>6</sup>

We also observe that Energex and Ergon Energy have departed from our rate of return guideline<sup>7</sup> to develop their proposed rates of return on their assets. We will consider whether the distributors' proposed rates of return achieve the allowed rate of return objective set out in the rules, that they reflect the efficient financing costs of a benchmark efficient entity with similar risk.<sup>8</sup>

We recognise some factors are putting upwards pressure on prices. These include the distributors' asset bases being larger than they were five years ago. These assets will require financing in the years to come. In addition, Energex has accrued a revenue under recovery in the 2010–15 period due in part to demand being weaker than expected as well as rising liabilities from the Qld Government's solar bonus scheme. As Energex (and Ergon Energy) operates under a revenue cap, it is entitled to carry forward under recovered revenues to the 2015–20 period.

Figures 1 and 2 show Energex and Ergon Energy's proposed revenues compared to their actual and allowed revenues in the current and previous periods. Proposed revenues for the 2015–20 period are shown both with and without the distributors' expected Solar Bonus Scheme feed-in tariff (FiT) costs.

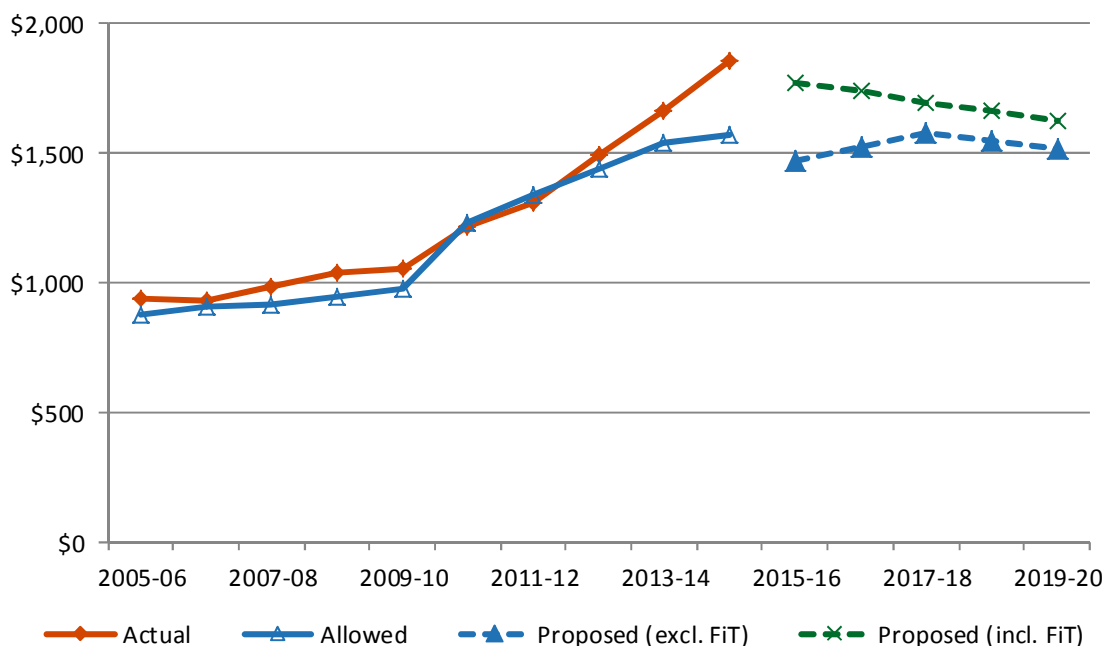
**Figure 1 Energex – proposed total revenue (\$million, 2014–15)<sup>9</sup>**



Source: Historical actual revenue from Energex's economic benchmarking RINs and reset RIN. Historical allowed revenue from our 2005–10 distribution determination (p. 177) and the post-tax revenue model (PTRM) for our 2010–15 determination. Energex's proposed revenues from its submitted PTRM.

<sup>6</sup> NER, cl. 6.5.6(c).  
<sup>7</sup> AER, *Rate of return guideline*, December 2013.  
<sup>8</sup> NER, cl. 6.5.2(b).  
<sup>9</sup> Includes FiT revenues.

**Figure 2 Ergon Energy – proposed total revenue (\$million, 2014–15)<sup>10</sup>**



Source: Historical actual revenue from Ergon Energy's economic benchmarking RINs and reset RIN. Historical allowed revenue from our 2005–10 distribution determination (p. 178) and the PTRM for our 2010–15 determination. Ergon Energy's proposed revenues from its submitted PTRM.

Key drivers of Energex and Ergon Energy's revenue proposals are:

### Energex

- Opex – We will assess whether Energex's proposed opex fully reflects its efficiency initiatives.
- Return on capital – Energex's regulatory asset base (RAB) is proposed to continue to grow by 21 per cent despite weak demand forecasts and lower capex.
- Revenue carry overs – including an under recovery of revenues from the 2010–15 period, which Energex is entitled to recover in the 2015–20 period.

### Ergon Energy

- Opex – We will assess whether Ergon Energy's proposed opex fully reflects its efficiency initiatives.
- Return on capital – Ergon Energy's RAB is proposed to continue to grow by 27 per cent despite weak demand forecasts and lower capex.

<sup>10</sup> Includes FiT revenues.

### 3 Capital expenditure

The most significant elements of total capex are generally network augmentation expenditure (augex), asset replacement expenditure (repex) and connections. Over the next five years, Energex has proposed total capex 33 per cent lower than its actual capex in the current period. Ergon Energy has proposed a more modest total capex reduction of around 18 per cent. These lower capex forecasts reflect lower forecast expenditure on augmentation, while expenditure on aged asset replacement is expected to rise. Asset replacement is an increasing proportion of the distributors' capex proposals. The distributors suggest weaker demand and less onerous requirements for network security and reliability are the drivers on lower augmentation expenditure. Notably, Ergon Energy anticipates a substantial increase in expenditure relating to customer connections.

Capex refers to the capital expenses incurred in the provision of network services. Capex is added to the RAB and so forms part of the capital costs of the building blocks used to determine a distributor's total revenue requirement. Under the rules, we must accept a distributor's proposed forecasts of total capex if we are satisfied they reasonably reflect the capex criteria.<sup>11</sup> The capex criteria relate to the efficient costs incurred by a prudent operator in light of realistic demand forecasts. We must have regard to the capex factors in the rules when making that decision.<sup>12</sup>

If we are not satisfied a distributors' capex proposal reasonably reflects the capex criteria, we must not accept the forecast. In that case, we must estimate the total required capex that, in our view, does reasonably reflect the capex criteria taking into account the capex factors. The approach we will adopt to assess the services providers' forecasts of total capex is outlined in our expenditure forecast assessment guideline.<sup>13</sup>

#### Question

Do you think that the distributors' capital expenditure proposals are adequately justified?

#### 3.1 Distributors' capital expenditure proposals

Table 2 summarises forecast standard control services capex proposed by Energex and Ergon Energy.<sup>14</sup> The distributors have proposed capex levels significantly lower than their actual capex for the 2010–15 period.

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<sup>11</sup> NER, cl. 6.5.7(c).

<sup>12</sup> NER, cl. 6.5.7(e).

<sup>13</sup> AER, *Expenditure forecast assessment guideline*, November 2013.

<sup>14</sup> Standard control services include the core activities of planning, constructing and operating a distribution network. It is not practical to separately charge individual consumers for these network services, so the cost of providing standard control services is averaged across all electricity consumers. These averaged costs are recovered from all consumers through distribution network charges.

**Table 2 Qld distributor capital expenditure proposals<sup>15</sup>**

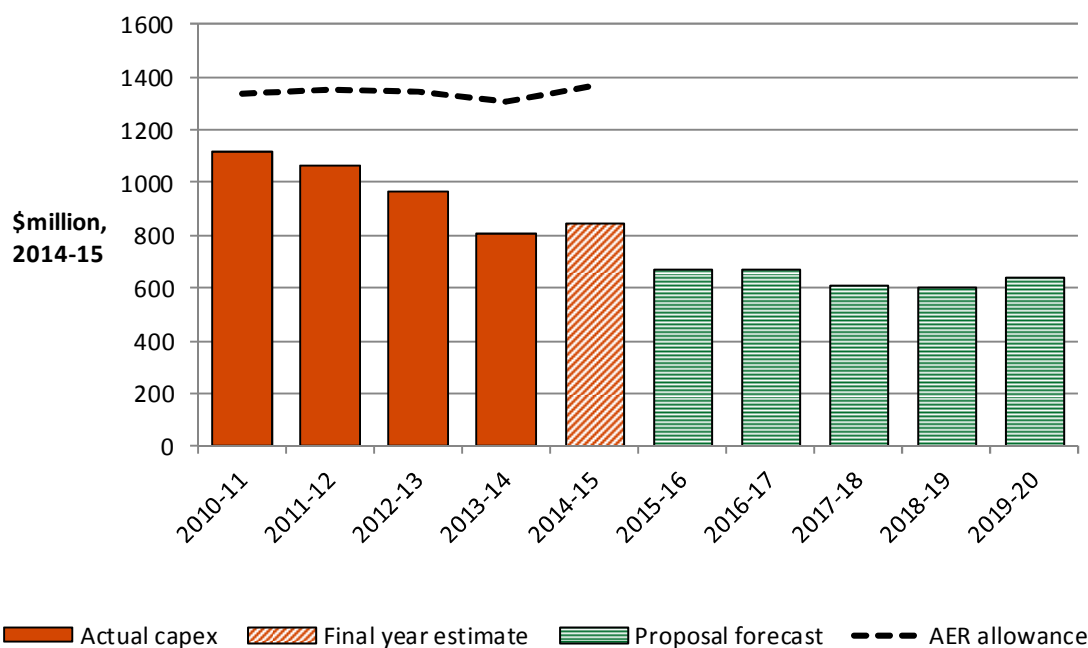
Distributor	2015–20 total capex proposal (\$million, 2014–15)	Change from 2010–15 total actual capex (per cent)
Energex	\$3,197.0	- 33.4 per cent
Ergon Energy	\$3,462.2	- 18.3 per cent

Source: Actual total capex is drawn from the distributors' submitted Roll Forward Models (RFM). Proposed capex is drawn from the "assets" sheet of the distributors' submitted PTRM.

The distributors' capex proposals are very similar to each other overall although differences exist when the proposals are examined in detail. Figures 3 and 4 below compare the distributors' forecasts with their 2010–15 capex allowances and actual outcomes.

The distributors significantly under spent their capex allowances in the 2010–15 period. This means that their opening RABs for the 2015–20 period are lower than anticipated. It also suggests the previous allowances may have been higher than necessary. This lower actual spending compared to the allowances we approved reflects a number of factors, including lower than forecast peak demand, revised security and reliability standards and improved governance processes.

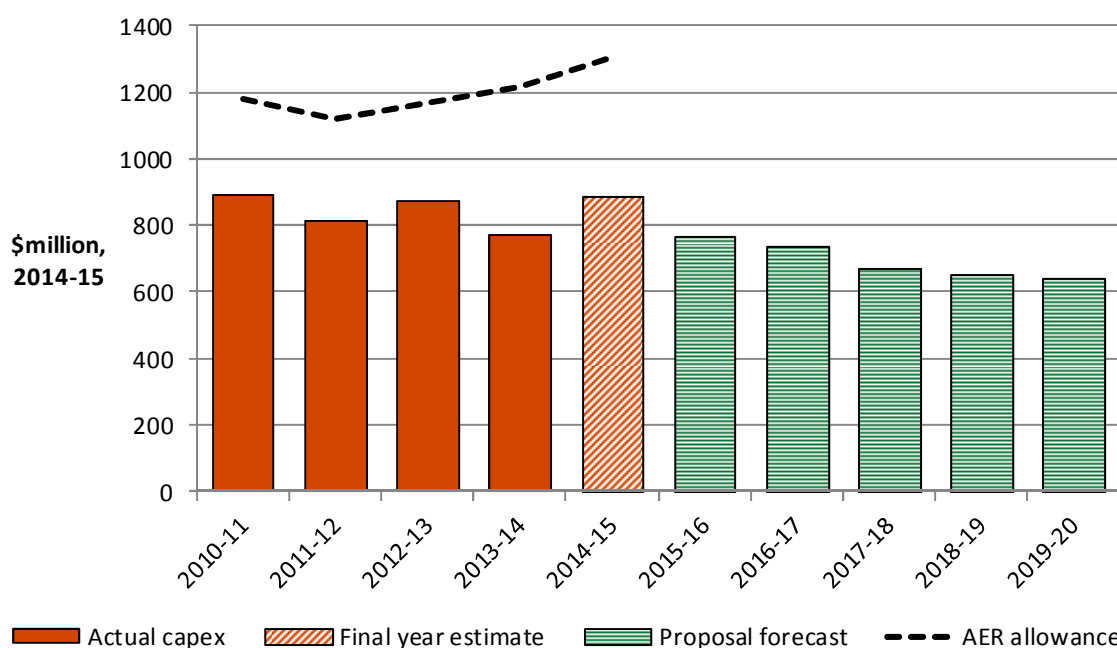
**Figure 3 Energex – capital expenditure**



Source: AER capex allowance is drawn from the PTRM determined by the AER for the 2010–15 period as varied by the Australian Competition Tribunal (the Tribunal). Actual capex is drawn from Energex's submitted RFM. Proposed capex is drawn from Energex's submitted PTRM.

<sup>15</sup> We have drawn the capex amounts shown in this table from the distributors' submitted financial models, rather than from their written regulatory proposals. The amounts shown here exclude the distributors' forecast capital contributions and asset disposals.

**Figure 4 Ergon Energy – capital expenditure**



Source: AER capex allowance is drawn from the PTRM determined by the AER for the 2010–15 period as varied by the Australian Competition Tribunal (the Tribunal). Actual capex is drawn from Ergon Energy's submitted RFM. Proposed capex is drawn from Ergon Energy's submitted PTRM.

## 3.2 Key drivers of the distributors' capital expenditure proposals

Energex and Ergon Energy submitted that their capex requirements are substantially influenced by the need to maintain high levels of network reliability and to replace ageing assets.<sup>16</sup> They also proposed that some capex will be required to respond to pockets of demand growth across their networks.

### Reliability

Energex and Ergon Energy submitted that feedback from their consumer engagement activities supports maintaining current levels of reliability, if achieved without additional price increases.<sup>17</sup> The distributors have also suggested that, for some consumers, service levels require improvement. Accordingly, Energex and Ergon Energy's proposals include levels of capex (and opex) which, they have submitted, are intended to maintain current levels of service and to improve service levels in some areas.

The distributors have also noted that adjusted reliability standards in Qld will contribute to lower capex over the 2015–20 period.

### Asset renewal/replacement

Table 3 summarises the total replacement expenditure (repex) forecast proposed by each of the distributors for the 2015–20 period.

<sup>16</sup> Energex, *Regulatory proposal*, p. 4. Ergon Energy, *Regulatory proposal*, Appendix B.

<sup>17</sup> Energex, *Regulatory proposal - appendices - Connecting with you, customer engagement strategy* p. 10. Ergon Energy, *Regulatory proposal - supporting documentation - Informing our plans, our engagement program*, p. 16.

**Table 3 Qld distributor replacement capital expenditure proposals**

Distributor	Proposed repex 2015–20 period (\$million, 2014–15)	Proportion of distributors' total 2015–20 capex proposal	Change from actual repex in 2010–15 period
Energex	\$1,773.0	55 per cent	+ 66 per cent
Ergon Energy	\$1,358.1	33 per cent	+ 10 per cent

Source: Energex repex drawn from table 9.1 of its regulatory proposal. Ergon Energy repex drawn from table 42 of its regulatory proposal. The percentage changes from the 2010–15 period are drawn from the distributors' submitted reset RINs, table 2.1.1.

Despite undertaking substantial replacement programs in the 2010–15 period, the distributors have submitted that the average age of network assets continues to increase. They argue that their proposed repex is required to maintain the average age of the network within an acceptable range, consistent with their reliability and safety obligations.

We consider the distributors' repex proposals to be a key issue for our assessment of their regulatory proposals overall. This is particularly the case for Energex, given its relatively high repex proportion of total capex. Our general expectation is that repex levels should remain relatively constant over time.

### Responding to growth

Although there has been a decline in growth in electricity demand across each of the networks during the 2010–15 period, the distributors have proposed material amounts of growth related capex in the 2015–20 period. Table 4 summarises the total augmentation expenditure (augex) forecast by the distributors for the 2015–20 period.

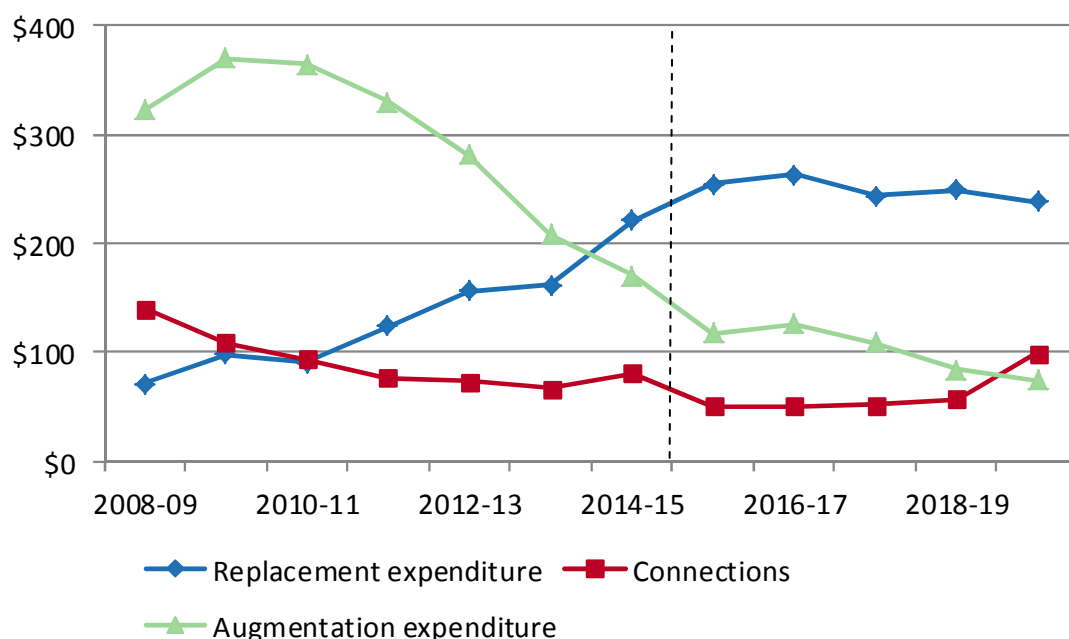
**Table 4 Qld distributor augmentation capital expenditure proposals**

	Proposed augex 2015–20 period (\$million, 2013–14)	Proportion of distributors' total 2015–20 capex proposal	Change from actual augex in 2010–15 period
Energex	\$726.0	22 per cent	– 62 per cent
Ergon Energy	\$790.5	19 per cent	– 14 per cent

Source: Energex augex drawn from table 9.1 of its regulatory proposal. Ergon Energy augex drawn from table 42 of its regulatory proposal. The percentage changes from the 2010–15 period are drawn from the distributors' submitted reset RINs, table 2.1.1

Figures 5 and 6 below show Energex and Ergon Energy's proposed repex, augex and connections spending compared to their actual spending in the 2010–15 period. To the right of the dashed vertical line are the distributors' proposals for the 2015–20 period.

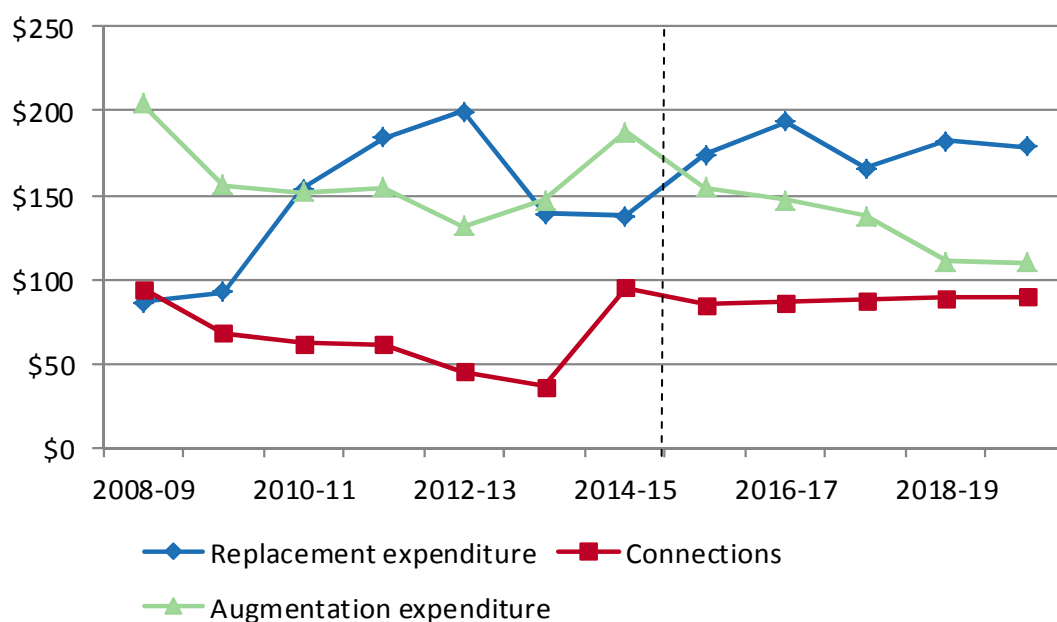
**Figure 5 Energex – capital expenditure components (\$million, 2014–15)**



Source: Energex's submitted reset RIN, table 2.1.1.

In figure 5 we can see Energex's higher forecast level of repex is largely offset by lower expected augex across the forecast period. In figure 6 we can see Ergon Energy has also proposed to largely substitute declining augex with increasing repex, though a long term trend is less apparent. Ergon Energy's proposed connections expenditure will require close examination. We will investigate why Ergon Energy's proposed connections expenditure rises sharply in 2014–15 and remains at a relatively high level compared to the earlier five years.

**Figure 6 Ergon Energy – capital expenditure components (\$million, 2014–15)**



Source: Ergon Energy's submitted reset RIN, table 2.1.1.



## Demand growth

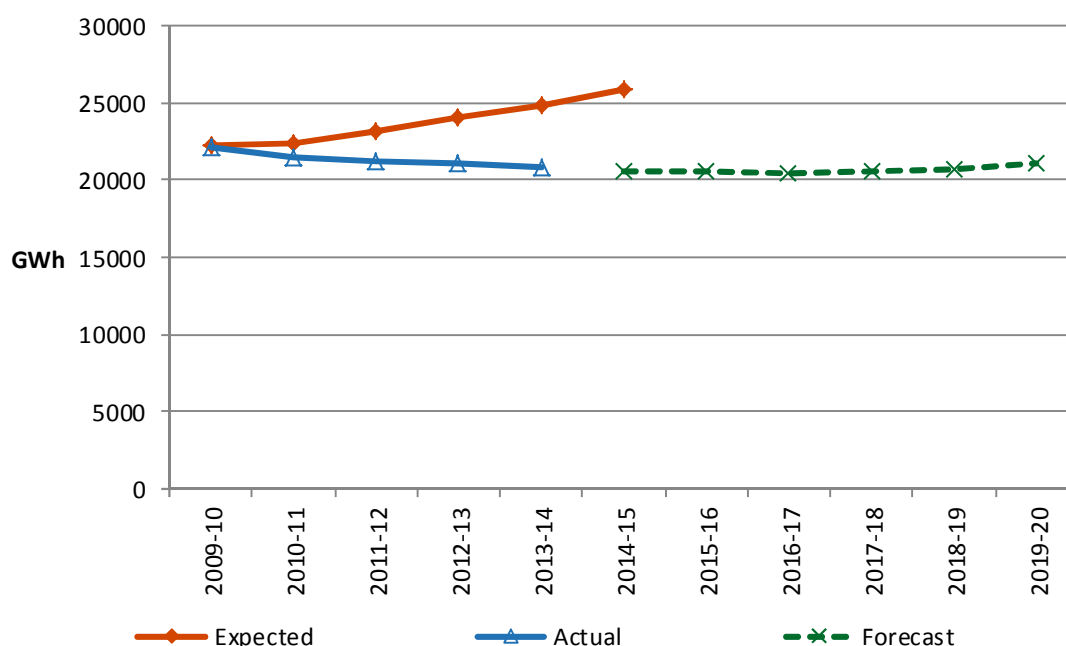
While total demand, or network wide electricity volumes, is an indicator of the overall pressure on the networks to invest in their capacity, peak demand is a more significant driver of augex requirements. The distributors' forecasts for peak demand reflect an expected moderate reversal of the recent trend.

Energex expects average annual growth in peak demand of 1.1 per cent in the 2015–20 period. This contrasts with its experience from 2009–10 to 2013–14, when Energex experienced an average annual decline in peak demand of 0.5 per cent.

Ergon Energy expects average annual growth in peak demand of 2.2 per cent in the 2015–20 period. Between 2009–10 and 2013–14, Ergon Energy experienced an average annual decline in peak demand of 0.1 per cent.

Like peak demand, we note consumption volumes in the distributors' service areas have been flat or in decline since 2009–10. Figures 7 and 8 show Energex and Ergon Energy's consumption volume forecasts for the 2015–20 period, with their expected and actual consumption volumes in the 2010–15 period. Both distributors expect continuing flat consumption volumes with only modest growth more evident towards the end of the 2015–20 period.

**Figure 7 Energex – electricity volumes (consumption)**

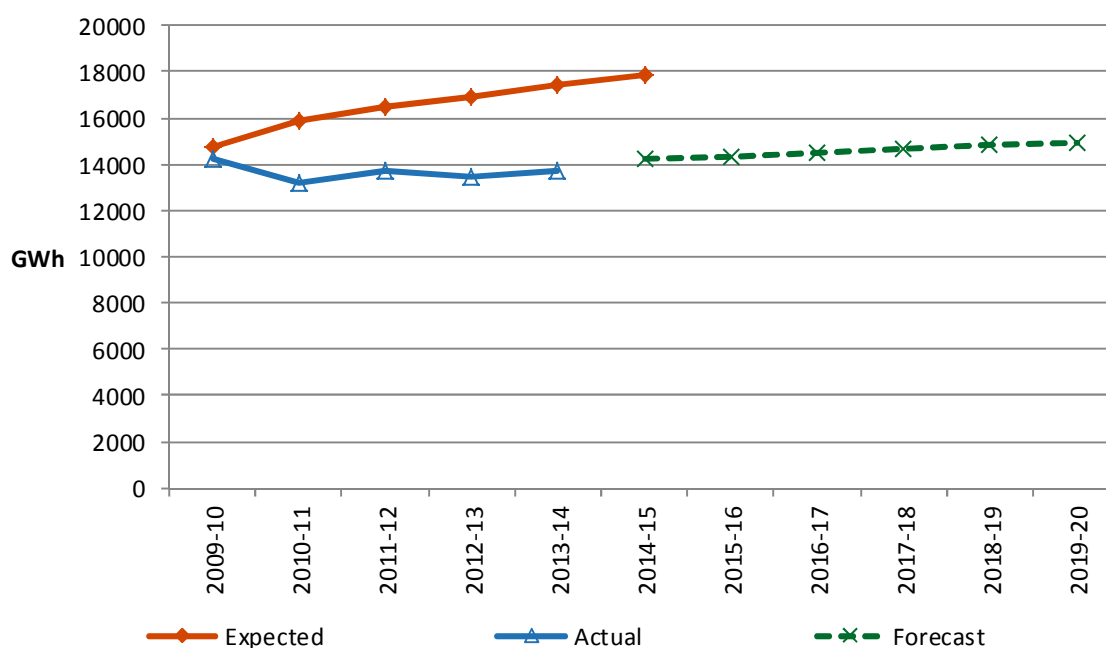


Source: Historical actual volumes are drawn from Energex's submitted economic benchmarking RINs. Forecasts are drawn from Energex's submitted reset RIN.

Energex submitted that it expects air conditioning take up across its consumer base to continue, albeit at a slower rate than in the past.<sup>18</sup> Energex noted its consumers have changed their behaviour in response to electricity price increases.

<sup>18</sup> Energex, *Regulatory proposal*, p. 90.

**Figure 8 Ergon Energy – electricity volumes (consumption)**



Source: Historical volumes are drawn from Ergon Energy's submitted economic benchmarking RINs. Forecasts are drawn from Ergon Energy's submitted reset RIN.

Ergon Energy submitted that it expects to see increasing demand in its central Qld and southern Qld regions in addition to coastal ports, driven by resource companies.<sup>19</sup> It referred to LNG extraction activities in the Darling Downs and to investment in nearby communities as service and support centres.

## Demand management

Demand management refers to any strategy to mitigate growth in consumption volumes or peak demand. Demand management can have positive economic impacts by encouraging more efficient use of existing network assets, resulting in lower prices for network users, reduced risk of stranded network assets and benefits for the environment. Demand management is an integral part of good asset management for network businesses.

In some circumstances, demand management can provide efficient alternatives to network investments, by deferring the need for augmentations to relieve network constraints. Costs of network augmentation projects can be significantly greater than the costs of conducting demand management projects to defer an augmentation project. Deferral of network investment may result in efficiency benefits, as the same level of reliability and service is provided by a smaller, better utilised network.

Network owners can undertake demand management through a range of mechanisms. These include incentives for consumers to change their demand patterns, operational efficiency programs, load control technologies, or alternative sources of supply (such as distributed or embedded generation and energy storage).

<sup>19</sup> Ergon Energy, *Regulatory proposal*, p. 103.

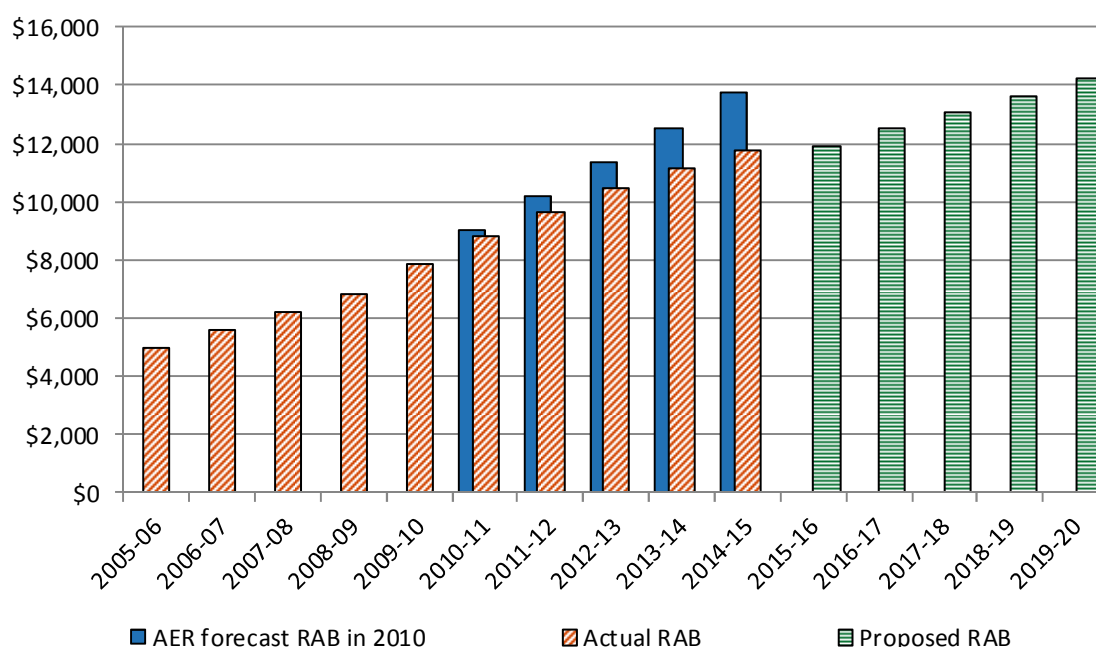
Energex submitted that its demand management programs over the 2010–15 period have been successful in achieving its demand reduction target.<sup>20</sup> Energex has submitted a further demand management program for the 2015–20 period. Ergon Energy also submitted that it has successfully deferred capex spending in the 2010–15 period through its demand management programs.<sup>21</sup> It also proposed to continue to invest in demand management over the 2015–20 period.

### 3.3 Regulatory asset base proposals

A distributors' RAB is the outcome of its cumulative capex spending. While Energex and Ergon Energy have proposed lower capex spending in the 2015–20 period than in the 2010–15 period, their RABs are proposed to continue to grow. Assets purchased or constructed by the distributors will earn a rate of return until their value depreciates away over a number of years.

Figures 9 and 10 show Energex and Ergon Energy's proposed RAB values compared to their past and current annual RAB values.

**Figure 9** Energex – regulatory asset base (RAB) values (\$nominal)



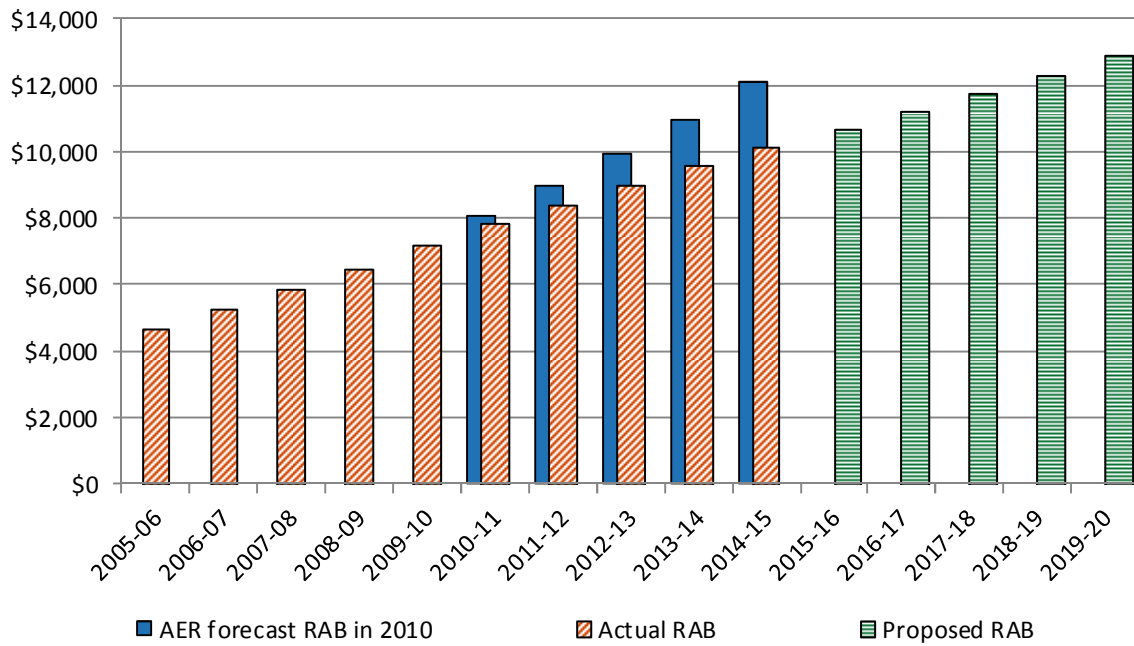
Source: Historical actual RAB values are drawn from Energex's submitted roll forward model (RFM). Energex's proposed RAB values are drawn from its submitted PTRM.

Energex proposed to increase its RAB by around 21 per cent and Ergon Energy by around 27 per cent. We acknowledge electricity network assets have long effective lives, so assets established in the current and previous periods will continue to add to consumer costs for a number of years. However, given the distributors' relatively flat demand forecasts, we will investigate why the RABs are proposed to continue to grow so significantly.

<sup>20</sup> Energex, *Regulatory proposal*, p. 80.

<sup>21</sup> Ergon Energy, *Regulatory proposal*, p. 95.

**Figure 10 Ergon Energy – regulatory asset base (RAB) values (\$nominal)**



Source: Historical actual RAB values are drawn from Ergon Energy's submitted roll forward model (RFM). Ergon Energy's proposed RAB values are drawn from its submitted PTRM.

## 4 Operating expenditure

Energex has proposed opex levels around 5 per cent lower than its actual opex in the 2010–15 period. Energex suggested the decrease in opex is a result of efficiencies achieved in network management, contract management and overheads.<sup>22</sup> Ergon Energy has proposed opex levels around 13 per cent lower than its actual opex in the 2010–15 period, also driven by maintenance and management efficiencies.<sup>23</sup>

Opex refers to the operating, maintenance and other non-capital expenditure incurred in the provision of network services. It includes labour costs and other non-capital costs that a prudent service provider is likely to require during the 2015–20 period for the efficient operation of its network. It is one of the building blocks used to determine the distributors' total revenue requirement. Under the rules, we must accept a distributors' forecast of total opex if we are satisfied it reasonably reflects the opex criteria.<sup>24</sup> The opex criteria relate to the efficient costs incurred by a prudent operator in light of realistic demand forecasts. We must have regard to the opex factors when making that decision.<sup>25</sup>

If we are not satisfied a distributors' opex proposal reasonably reflects the opex criteria, we must not accept it.<sup>26</sup> We must estimate the total required opex that, in our view, reasonably reflects the opex criteria taking into account the opex factors. The approach we will adopt to assess the distributors' forecasts of total opex is outlined in our expenditure forecast assessment guideline.<sup>27</sup>

### Question

Are the distributors' operating expenditure proposals justified?

### 4.1 Distributors' operating expenditure proposals

Table 5 summarises forecast standard control services opex proposed by each of the distributors.

**Table 5 Qld distributors' forecast standard control services opex (\$million, 2014–15)<sup>28</sup>**

Distributor	2015–16	2016–17	2017–18	2018–19	2019–20	Total
Energex	343.5	336.5	345.0	355.9	358.1	\$ 1,739.0
Ergon Energy	361.2	368.0	375.9	385.4	391.8	\$ 1,882.3

Source: Energex, *Regulatory proposal*, table 10.1; Ergon Energy, *Regulatory proposal*, table 35.

Figures 11 and 12 below show the proposed opex spending by Energex and Ergon Energy in the 2015–20 period.

<sup>22</sup> Energex, *Regulatory proposal*, p. 6.

<sup>23</sup> Ergon Energy, *Regulatory proposal*, p. 64.

<sup>24</sup> NER, cl. 6.5.6(c).

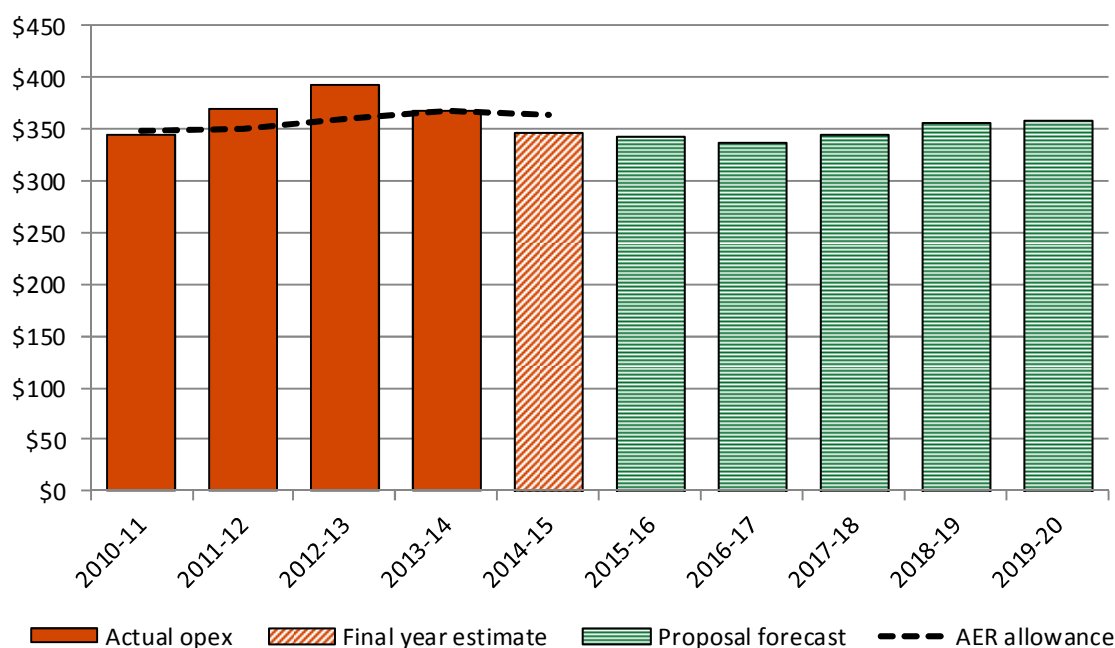
<sup>25</sup> NER, cl. 6.5.6(e).

<sup>26</sup> NER, cl. 6.5.6(d).

<sup>27</sup> AER, *Expenditure forecast assessment guideline*, November 2013.

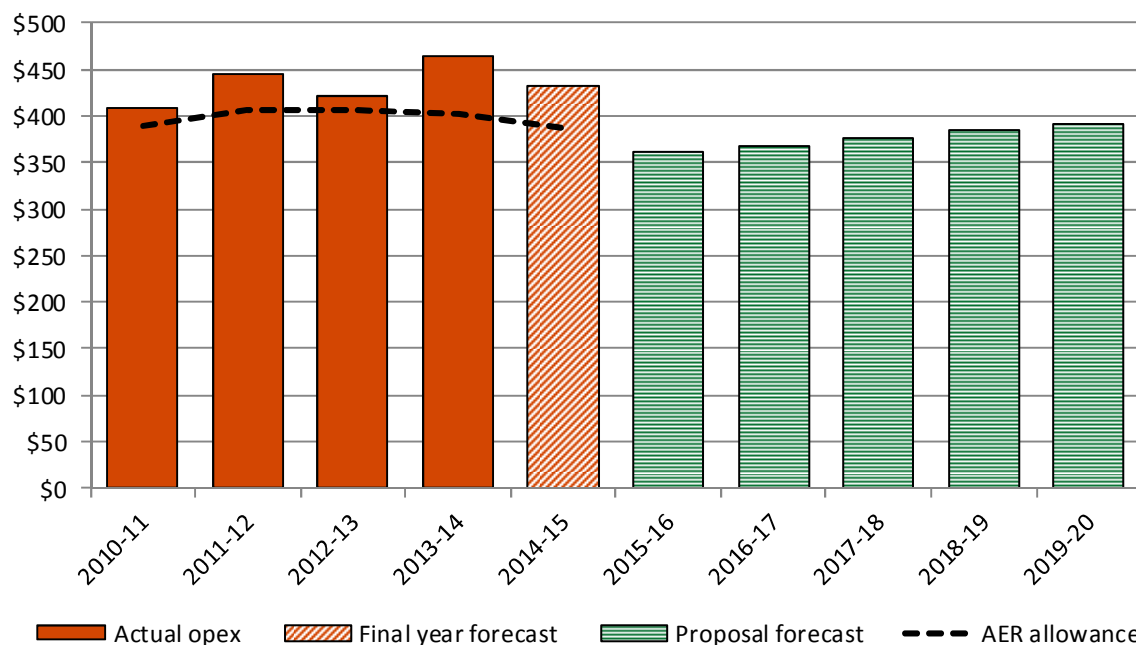
<sup>28</sup> Opex costs shown exclude the distributors' FIT costs.

**Figure 11 Energex – operating expenditure (\$million, 2014–15)**



Source: Historical opex amounts are drawn from the Energex's submitted reset regulatory information notice (RIN). Forecast opex amounts are drawn from Energex's submitted PTRM. The historical opex allowance is drawn from the Tribunal varied PTRM for the 2010–15 period.

**Figure 12 Ergon Energy – operating expenditure (\$million, 2014–15)**



Source: Historical opex amounts are drawn from Ergon Energy's submitted reset RIN. Forecast opex amounts are drawn from the Ergon Energy's submitted PTRM. The historical opex allowance is drawn from the Tribunal varied PTRM for the 2010–15 period.

## 4.2 Key drivers of the distributors' operating expenditure proposals

The distributors identified a number of drivers affecting forecast opex. A summary of the main drivers Energex and Ergon Energy identified is outlined in tables Table 6 and Table 7 below.

**Table 6 Energex—Drivers of opex forecast**

Expenditure driver	Description
Base year adjustments	<p>Energex made a number of adjustments to its reported expenditure in 2012–13, which it used as its base year, including:</p> <ul style="list-style-type: none"> <li>▪ removing restructuring expenditure (\$51 million)</li> <li>▪ substituting actual emergency response and corrective repair expenditure with an historical 10 year average (reduction of \$9.3 million)</li> <li>▪ accounting for provisions (an additional \$3.4 million)</li> <li>▪ removing expenditure relating to cancelled projects (\$16 million)</li> <li>▪ removing expenditure related to reclassified services (\$15.3 million)</li> <li>▪ adjustments to property and fleet expenditure to reflect full year costs (additional \$3.9 million) and</li> <li>▪ additional expenditure to support the program of work (\$6.4 million).</li> </ul>
Significant cost items	<p>Energex identified a number of non-recurrent costs that it expected to incur, or not incur in the 2015–20 regulatory control period, including:</p> <ul style="list-style-type: none"> <li>▪ adding a metal passivator to transformers testing positive for corrosive sulphur and cleaning the selector switches of high-risk, bulk supply transformers (\$3.8 million, 2012–13 direct dollars)</li> <li>▪ reducing property rental expenditure by sub-leasing or the expiry of leases (\$20.5 million, 2012–13 direct dollars)</li> </ul>
Step changes	<p>Energex included additional expenditure for changes in scope that it considered would have an ongoing impact on future recurrent costs, including:</p> <ul style="list-style-type: none"> <li>▪ additional expenditure to remove asbestos following the release of the National Strategic Plan for Asbestos Awareness and Management in July 2013 (\$1.5 million, 2012–13 direct dollars)</li> <li>▪ reduced vegetation management expenditure resulting from a new contracting model with its suppliers (\$37.9 million, 2012–13 direct dollars)</li> <li>▪ reduced network operating costs from changes to Energex's distribution management system (\$7.5 million, 2012–13 direct dollars)</li> <li>▪ additional expenditure to comply with NECF from 1 July 2015 (a forecast of this expenditure was included in Energex's opex forecast but is expected to be included in its revised regulatory proposal).</li> </ul>
A growing asset base	<p>Energex applied three growth factors to its opex forecast:</p> <ol style="list-style-type: none"> <li>1. Network growth based on forecast increase in line length, distribution transformers and installed capacity. This driver was applied to inspections, planned maintenance and network operating activities.</li> <li>2. Customer growth based on forecast customer numbers. This driver was applied to customer service activities.</li> </ol>

Expenditure driver	Description
	<p>3. Solar PV growth based on the forecast of installed solar PV capacity. This driver has been applied to activities associated with power quality investigations and remediation works, such as phase rebalancing.</p> <p>The output growth factors were adjusted for economies of scale.</p>
Demand management initiatives	<p>Energex proposed a suite of demand management initiatives, to reduce the need to increase network capacity. Energex's demand management program comprises the following core elements:</p> <ul style="list-style-type: none"> <li>▪ targeted area demand management for areas where significant investment is expected</li> <li>▪ broad based demand management</li> <li>▪ power factor correction for consumers on demand (kVA) tariffs</li> <li>▪ managing and optimising existing load control.</li> </ul>
Forecast labour, contractor and materials cost growth	Energex included forecast real price changes in labour, materials and contractor costs.
Delivery of efficiencies	Energex included forecast efficiencies in its opex proposal including reduced overhead costs resulting from Energex's business efficiency program (\$247.8 million, 2012–13 direct dollars).

Source: Energex, *Regulatory proposal*.

**Table 7 Ergon Energy—Drivers of opex forecast**

Expenditure driver	Description
Base year adjustments	Ergon Energy reduced its 2012–13 opex by \$60.5 million to remove expenditure that related to specific one-off or unusual events. It also removed movements in provisions from its base year expenditure.
Output growth	<p>Ergon Energy applied two growth drivers in its opex forecast:</p> <ol style="list-style-type: none"> <li>1. A customer growth driver calculated as the annual forecast growth in customer numbers over the 2015–20 regulatory control period.</li> <li>2. A network growth driver calculated as a simple average of the forecast annual growth in zone substation capacity, distribution line length and the number of distribution transformers over the 2015–20 regulatory control period.</li> </ol>
Price growth	Ergon Energy included forecast real price changes in labour, materials and contractor costs.
Productivity growth	<p>Ergon Energy adjusted its forecast output growth for economies of scale achievable across the network growth and customer growth drivers.</p> <p>Ergon Energy also applied a productivity growth factor of 1 per cent per annum to all direct and support costs.</p>
Step changes	<p>Ergon Energy included step changes in its forecast opex for:</p> <ul style="list-style-type: none"> <li>▪ non network ICT, \$51.0 million (\$2012–13)</li> <li>▪ AEMO testing requirements, \$5.0 million (\$2012–13)</li> <li>▪ non network alternatives, \$17.5 million (\$2012–13)</li> </ul>
Non-recurrent adjustments expenditure	Ergon Energy applied non-recurrent expenditure adjustments to its forecast opex for expenditure it considered was not incorporated in the base year, but was required in a certain year. It made adjustments for:



Expenditure driver	Description
Bottom up	<ul style="list-style-type: none"> <li>▪ remediation of contaminated land, \$6.0 million (\$2012–13)</li> <li>▪ regulatory reset costs, \$6.0 million (\$2012–13)</li> </ul> <p>Ergon Energy applied a bottom-up forecasting method for functional areas it considered were uncontrollable costs or are non-recurrent in nature, including:</p> <ul style="list-style-type: none"> <li>▪ <b>Chumvale:</b> ‘Chumvale’ refers to the substation on the unregulated 220kV network which services Cloncurry. Charges for the use of this line have been treated as ‘designated pricing proposal charges’ and not reflected in the base year opex. (\$4.1 million, \$2014–15)</li> <li>▪ <b>Powerlink:</b> costs for entry and exit services charged by Powerlink at four non-prescribed connection points (Queensland Nickel, Stoney Creek, Kings Creek and Oakey Town). Charges have been treated as ‘designated pricing proposal charges’ and are not reflected in the base year opex. (\$11.8 million, \$2014–15)</li> <li>▪ <b>ICT:</b> Ergon Energy considered a base step trend forecasting method not suitable for forecasting some types of ICT expenditure. (\$208.0 million, \$2012–13)</li> <li>▪ <b>parametric insurance:</b> Ergon Energy has identified options for traditional insurance and parametric insurance to cover the cost of damage or loss of network assets caused by storms and cyclones. Previously these risks have been addressed by cost pass throughs. (\$57.2 million, \$2014–15)</li> </ul>
Overheads	<p>Ergon Energy applied a base step trend method to forecast its total overhead (support) costs. It then allocated costs between categories of distribution services in accordance with its cost allocation method.</p> <p>Forecast overheads account for \$480.5 million (2014–15) of Ergon Energy's total opex forecast.</p>

Source: Ergon Energy, *Regulatory proposal*; Ergon Energy, *Forecast Expenditure Summary—Operating Costs*, Ergon Energy, *Step Changes for Operating Costs*.

### 4.3 Step changes

Energex and Ergon Energy have proposed opex step changes, which are outlined in tables 7 and 8 above. Under our guideline forecasting approach, step changes allow for adjustments to forecast opex to account for changed circumstances in the forecast period that have not been addressed by base opex or the rate of change.<sup>29</sup> We may include step changes for changes to ongoing costs associated with new regulatory obligations and for efficient capex/opex trade-offs.<sup>30</sup> Step changes may be positive or negative. We may consider other components of the service providers' opex forecasts (such as base year adjustments or non-recurrent expenditure adjustments) as step changes within our guideline forecasting approach.

Energex also submitted it intends to propose a further step change for increasing costs arising from introduction of the National Energy Customer Framework (NECF) in Qld. Because details of NECF implementation are yet to be finalised, Energex intends to submit NECF step change costs within its revised regulatory proposal, due to be submitted to us by 2 July 2015.

We encourage you to review the distributors' submitted step change materials and submit to us your views to inform our assessment.

<sup>29</sup> AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 24.

<sup>30</sup> AER, *Expenditure assessment forecast guideline - Explanatory Statement*, November 2013, p. 51.

## 4.4 Forecast efficiency carryover amounts

To encourage a distributor to become more efficient, we typically apply an efficiency benefit sharing scheme (EBSS). In our Final Determination for the 2010-15 period, we determined that version 1 of the distribution EBSS established by the AER in June 2008 would apply to the distributors for the 2010-15 period.<sup>31</sup> This scheme sets out how carryover amounts will be calculated for the purpose of determining EBSS revenue in the 2015-20 period.

The EBSS rewards distributors for efficiency gains achieved during a regulatory control period and penalises them for efficiency losses. The distributors are allowed to retain their efficiency gains (losses) for a period of time. After five years, however, the efficiency improvements (or losses) are passed through to customers by way of lower (or higher) prices. The distributors receive rewards or penalties gained during 2010–15 in the 2015–20 period.

The distributors have included in their proposals carryover amounts that relate to the EBSS that applied during the 2010–15 period. The proposed carryover amounts are outlined in table 8 below.

**Table 8 Distributors' proposed EBSS carryover amounts (\$million, 2014–15)**

Distributor	Forecast carryover amounts
Energex	\$33.8
Ergon Energy	\$146.1

Source: The EBSS sheets in the distributors' submitted reset RINs.

Energex's proposed total EBSS carry over amount includes two years of negative adjustments. These reflect that Energex over spent its opex allowance in some years of the 2010–15 period. Ergon Energy proposed one year of negative EBSS adjustment, but this is strongly outweighed by its proposed positive EBSS adjustments in other years.

## 4.5 Solar Bonus Scheme

The Qld Solar Bonus Scheme (SBS) provides feed-in-tariff (FiT) payments to owners of small scale photovoltaic (PV) units. While payments to PV owners are made by retailers, those costs are passed on to the distributors who then recover the costs through their network charges (DUOS). The FiT costs incurred by Energex and Ergon Energy are not distribution related. Neither the distributors nor we are able to affect the amount of the costs to be recovered from consumers. However, we are able to smooth the impacts to avoid consumers experiencing unnecessary price fluctuations.

The costs of the SBS are significant. Energex forecasts FiT costs over the 2015–20 period to average \$182 million per year.<sup>32</sup> This is in addition to the delayed recovery of FiT costs incurred by Energex in the final two years of the 2010–15 period, totalling around \$477 million. Ergon Energy forecasts average annual FiT costs over the 2015–20 period of around \$105 million.<sup>33</sup>

<sup>31</sup> AER, *Queensland distribution determination 2010–11 to 2014–15*, May 2010, p. xxxii.

<sup>32</sup> Energex, *Regulatory proposal*, p. 8.

<sup>33</sup> Ergon Energy, *Regulatory proposal*, p. 38.

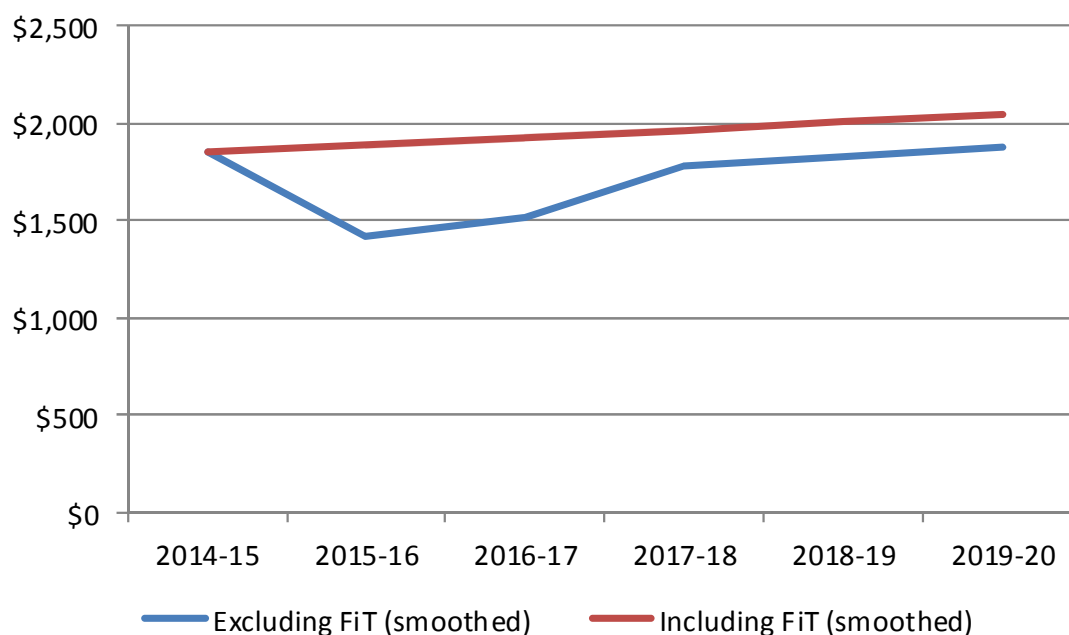
We note that the SBS and arrangements to recover FiT related costs are subject to change by the Qld Government.

In the first two years of the 2015–20 regulatory period, Energex and Ergon Energy will be eligible to recover their FiT costs for each of those years and their FiT costs from two years previous. This is because, in the 2010–15 period, FiT costs incurred by the distributors are passed on to consumers with a two year delay. The delay reflects the uncertainty about FiT costs at the time of our 2010 determination, when the SBS was new. Consumer take up of the SBS has been significantly greater than the FiT allowance we approved for the 2010–15 period. Because the costs of the scheme are now better understood, FiT costs for each year of the 2015–20 period may be more accurately forecast and included in the distributors' annual revenue allowances that we determine in advance. The double recovery for two years would create a price spike followed by a fall two years later.

Energex has adopted an approach to FiT recovery as described above. To avoid a price spike in 2015–16, Energex has smoothed its revenue requirement inclusive of FiT over the full 5 years of the 2015–20 regulatory period. Ergon Energy has taken a different approach. It has not proposed to smooth FiT revenues. Rather, Ergon Energy intends to retain the current two year delay into the future.

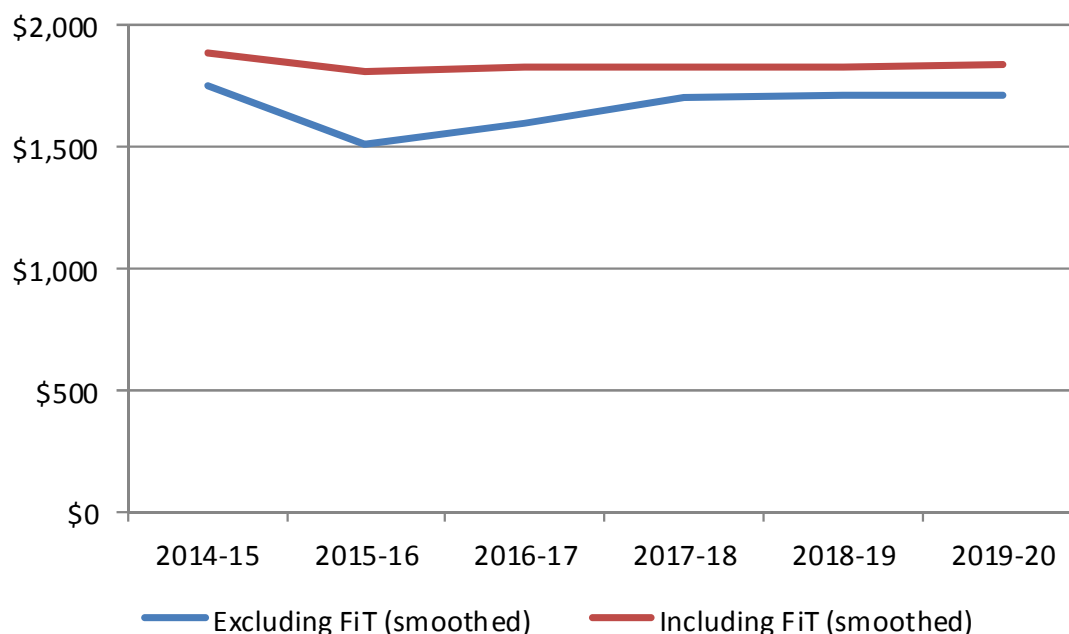
Figures 13 and 14 below show the impact of FiT revenues on Energex and Ergon Energy's proposed total revenues for standard control services, separating distribution charges from the FiT costs.

**Figure 13 Energex proposed total revenues – FiT impacts (\$million, nominal)**



Source: The revenue profile excluding FiT was drawn from Energex's submitted PTRM. The revenue profile including FiT was developed using FiT forecasts from table E3 on p. 8 of Energex's regulatory proposal.

**Figure 14 Ergon Energy proposed total revenues – FiT impacts (\$million, nominal)**



Source: The revenue profile excluding FiT was drawn from Ergon Energy's submitted PTRM. The revenue profile including FiT was developed using FiT forecasts from figure 1 on p. 4 of Ergon Energy's regulatory proposal.

## 4.6 Opex efficiency

Because opex is largely recurrent in nature, opex forecasts are developed using a base-step-trend approach. Under this approach, opex costs from a chosen base year are used as the starting point to forecast future opex. A key issue for us in assessing a distributors' forecast opex is the efficiency of its base year opex.

Our Expenditure Forecast Assessment Guideline,<sup>34</sup> sets out that we are interested in whether base opex is materially inefficient. If so, we may adjust the base year opex to account for any apparent level of inefficiency. While we apply a number of techniques to assess the efficiency of base opex, an important assessment technique is benchmarking.

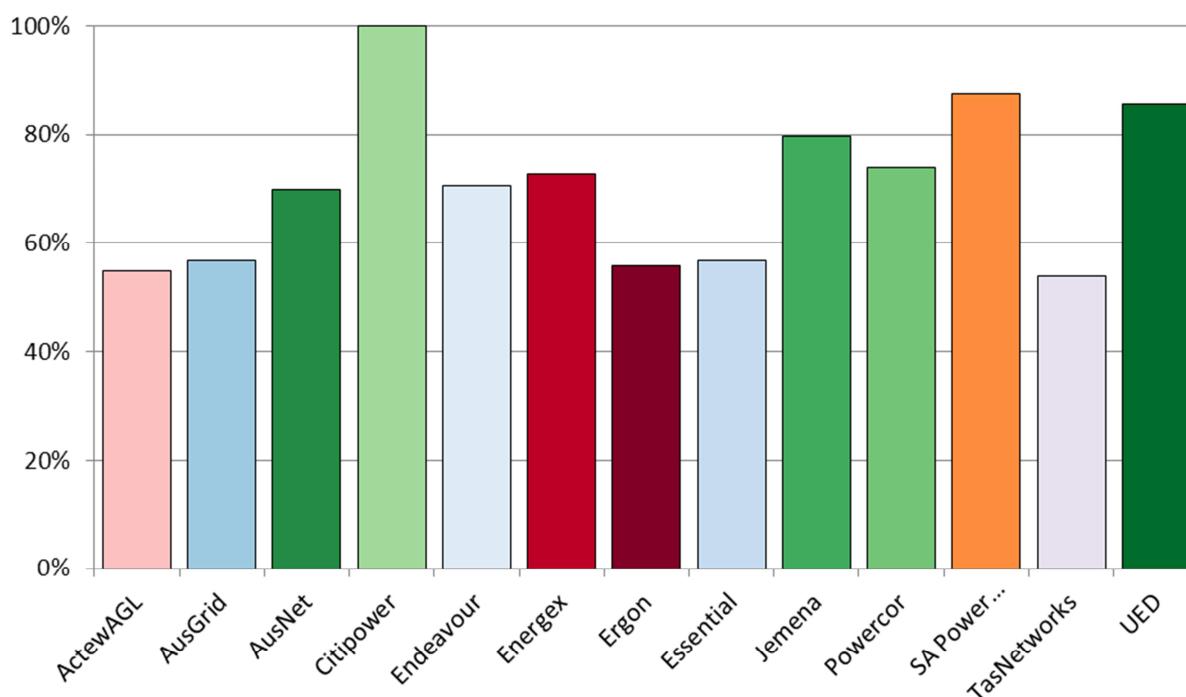
We recently published an annual benchmarking report covering all of the electricity network service providers in the National Electricity Market (NEM). We also recently released draft determinations on the NSW/ACT electricity distributors which include benchmarking techniques specific to opex. The work we undertook for those reports is relevant to the revenue proposals submitted by Energex and Ergon Energy. Figures 15 and 16 below show efficiency measures that relate the services delivered by distribution networks to the costs they incur in providing those services.<sup>35</sup>

Figure 15 shows the results of our overall benchmarks for NEM electricity distributors. That is, the relative efficiency of the distributors in terms of their total costs, including opex and capex. A higher percentage equates to a more efficient distributor relative to its peers.

<sup>34</sup> AER, *Expenditure Forecast Assessment Guideline*, November 2013.

<sup>35</sup> The methodology and assumptions used to calculate the above measures are set out in detail in our annual benchmarking report, and supporting report prepared by Economic Insights. These are available on our website [www.aer.gov.au](http://www.aer.gov.au).

**Figure 15 MTFP<sup>36</sup> Performance (average 2006–2013)**



Source: Economic Insights, 2014.

Figure 16 shows our opex specific benchmarks for distribution businesses.<sup>37</sup> We have had regard to these, partial performance indicator and other benchmarks in our recent draft determinations for the NSW and ACT networks.<sup>38</sup> Again, a higher index number equates to a more efficient distributor relative to its peers.

<sup>36</sup> Multilateral total factor productivity.

<sup>37</sup> The methods include a Cobb Douglas stochastic frontier analysis (SFA CD) opex cost function model, Cobb Douglas and translog least squares econometrics (LSE) opex cost function models and opex multilateral partial factor productivity (MPFP) indexes.

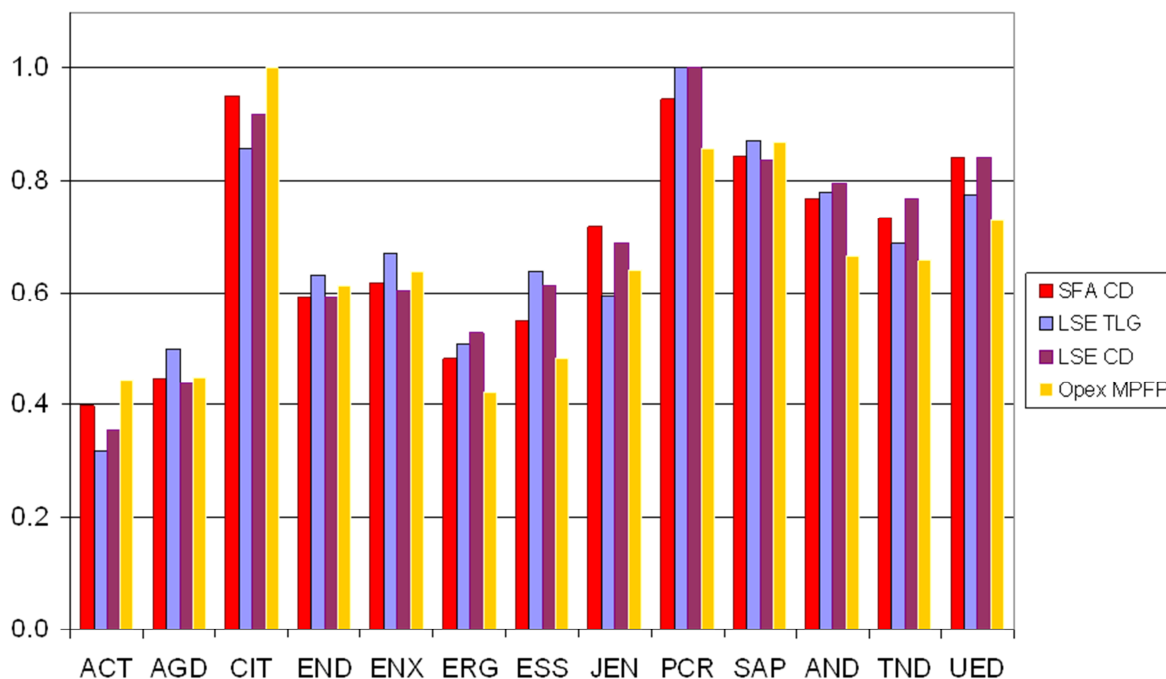
<sup>38</sup> AER, Draft decision, *Essential Energy distribution determination 2015–16 to 2018–19 – Attachment 7: Operating expenditure*, November 2014, pp7-55–7-71.

AER, Draft decision, *Endeavour Energy distribution determination 2015–16 to 2018–19 – Attachment 7: Operating expenditure*, November 2014, pp7-54–7-70.

AER, Draft decision, *Ausgrid distribution determination 2015–16 to 2018–19 – Attachment 7: Operating expenditure*, November 2014, pp7-55–7-71.

AER, Draft decision, *ActewAGL distribution determination 2015–16 to 2018–19 – Attachment 7: Operating expenditure*, November 2014, pp7-52–7-67.

**Figure 16 NEM service provider's average opex efficiency scores 2006 to 2013<sup>39</sup>**



Source: Economic Insights, 2014

Figures 16 and 17 indicate:

- there appears to be a performance gap between Energex and Ergon Energy and their peers, both in opex and overall
- there may be scope for Energex and Ergon Energy to make efficiency improvements.

That said, the gap in the performance of Energex and Ergon Energy relative to their peers could be attributable to external factors specific to Energex and Ergon Energy's networks and outside their control. We will investigate these issues as we assess their opex proposals and their overall regulatory proposals. If we were to make a revision to the opex forecasts to close the efficiency gap, a further issue to consider is how quickly this transition should take place. That is, who should bear the cost of the transition: consumers or shareholders?

We welcome submissions on the benchmarking results we have derived and their implications, whether from consumers or other stakeholders.

<sup>39</sup> Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, 17 November 2014, p. 46.

## 5 Rate of return

Energex has proposed a rate of return of 7.75 per cent,<sup>40</sup> while Ergon Energy has proposed 8.02 per cent.<sup>41</sup> The proposed rates of return are lower than the distributors received in the 2010–15 period (9.72 per cent). As noted previously, the distributors have proposed to depart from the Rate of Return Guideline.<sup>42</sup> Through this review we will assess the distributors' reasons for their proposed departures to determine whether they achieve the rate of return objective, that the rate of return reflect the efficient financing costs of a benchmark efficient entity with similar risk.

The allowed rate of return provides a distributor a return on capital to service the interest on its loans and give a return on equity to investors. 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 to attract new investment.
- The return on debt is the interest rate the distributor pays when it borrows money to invest in capex.

We consider that efficient distributors would fund their investments by borrowing 60 per cent of the required funds, while raising the remaining 40 per cent from equity. We consider certainty and predictability of outcomes in rate of return issues will materially benefit the long term interests of consumers.

When a distributor spends money on an asset, for example a new substation, the value of that substation is added to its RAB. The value of the RAB is multiplied by the allowed rate of return to determine the total return on capital the distributor can recover from consumers.<sup>43</sup> By setting a rate of return based on a benchmark, rather than the actual costs of individual businesses, a distributor has an incentive to finance its business as efficiently as possible.

After extensive consultation, we have developed a guideline that sets out our intended approach for determining the rate of return.<sup>44</sup> We published a Rate of Return Guideline in December 2013.<sup>45</sup> The guideline is not binding, but if we or the distributors seek to depart from it the rules require that we must set out reasons for doing so. Our allowed rate of return is commensurate with the efficient financing cost of a benchmark efficient entity providing regulated network services. This is estimated as a weighted average of the return on debt and equity. These are estimated relative to market data so that investors are compensated for the risk of providing capital to regulated network service providers.

We recently published our draft decision for eight electricity and gas network service providers across NSW, ACT and Tasmania (November 2014 draft decision).<sup>46</sup> Those draft decisions reflected the first time we have undertaken a full review of rate of return proposals (as part of a regulatory determination process) since we published the Rate of Return Guideline. In those draft decisions, we applied the guideline after carefully considering a large amount of material submitted to us. We were satisfied that applying the approach and methodologies set out in our guideline results in an allowed

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<sup>40</sup> Energex, *Regulatory proposal*, p. 6.

<sup>41</sup> Ergon Energy, *Regulatory proposal*, p. 121.

<sup>42</sup> AER, *Rate of return guideline*, December 2013.

<sup>43</sup> NER, cl. 6.5.2(a).

<sup>44</sup> AER, *Rate of return guideline*, December 2013.

<sup>45</sup> AER, *Rate of return guideline*, December 2013.

<sup>46</sup> [www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements](http://www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements)

rate of return that achieves the rate of return objective. Our findings were largely consistent with those at the time we made the guideline. However, we will consider the rate of return proposals from Energex and Ergon Energy taking into account the merits of the arguments they put forward, rather than what we determined in our draft determinations for the other network service providers.

### Questions

Do you consider that any departures from the Rate of Return Guideline are justified?

In particular, do you have any comments on the departures from the guideline proposed by the businesses?

## 5.1 Distributors' proposed overall rate of return

Table 7 below summarises the distributors' rate of return proposals. The first row shows the overall rate of return, or weighted average cost of capital (WACC), proposed by Energex and Ergon Energy. The following rows show the distributors' proposed values for the individual components that, when combined, make up the WACC. These are the return on equity, return on debt, gearing ratio and the value of imputation credits.

**Table 9** Distributors' proposed rates of return

	Energex	Ergon Energy
Overall WACC	7.75	8.02
Return on equity	10.50	10.53
Return on debt	5.91	6.36
Gearing	60 per cent	60 per cent
Value of imputation credits	0.25	0.25

Source: Energex, *Regulatory proposal*, pp. 152, 179–180; Ergon Energy, *Regulatory proposal*, pp. 121, 148.

### Regulated rate of return

The investment environment has improved since our last determinations for Energex and Ergon Energy, made during 2009 and early 2010. Those determinations were made during the uncertainty surrounding the global financial crisis. This resulted in us setting high rates of return for the distributors for the 2010–15 period. These allowed rates of return largely reflected the risks perceived across the broader economy in the wake of significant turmoil in global financial markets. Since our last determinations, interest rates and perceptions of economy wide risk have eased. As a consequence, lower rates of return may now be more appropriate.

Both distributors have used methods other than those set out in the Rate of Return Guideline to develop their proposed rates of return. While we consider the guideline sets out an appropriate approach, we do not wish to preclude stakeholder submissions proposing alternative approaches to both the guideline and the distributors' proposals.



We also note that the return on debt numbers apply only for the first regulatory year (2015–16). Each of the distributors has proposed to annually update the return on debt. This approach is consistent with the guideline.

## Departures from the Rate of Return Guideline

The distributors rate of return proposals have departed from the guideline for the following rate of return components:

- Energex
  - estimating the return on equity
  - method for averaging the return on debt estimates
  - return on debt benchmark credit rating
  - return on debt minimum averaging period
  - estimating the value of imputation credits.
- Ergon Energy
  - choice of rate of return model
  - estimating the return on equity
  - return on debt benchmark credit rating
  - method for averaging the return on debt estimates
  - estimating the value of imputation credits.

## 5.2 Return on equity

Both Energex and Ergon Energy submitted they had departed from the Rate of Return Guideline to estimate the return on equity.<sup>47</sup> In summary, both did not adopt the foundation model approach and instead, applied an approach developed by SFG Consulting.<sup>48</sup> This approach (subject to recent updates for market data on the risk free rate by SFG Consulting) was previously proposed by Jemena Gas Networks and ActewAGL, and reviewed by us in the recent draft decisions.<sup>49</sup>

The Rate of Return Guideline recognises there is not one perfect model to estimate the return on equity. Rather, we apply an iterative six step process (foundation model approach) which also draws on a variety of models and information we have assessed as relevant. We use a range of models, methods, and information to inform our return on equity estimate. We may use this information to set the range of inputs into the foundation model. Or we may use it to assist in determining a point estimate, within the range of estimates of overall return on equity resulting from the foundation model.

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<sup>47</sup> Energex, *Regulatory proposal*, p. 155–157; Ergon Energy, *Regulatory proposal*, p. 125

<sup>48</sup> SFG, *The required return on equity for regulated gas and electricity network businesses*, May 2014; SFG, *Updated estimate of the required return on equity*, August 2014; SFG, *Estimating the required return on equity*, August 2014.

<sup>49</sup> JGN, *Access arrangement information*, June 2014, pp. 95–96; ActewAGL, *Regulatory proposal*, May 2014, p. 261. AER, *Draft decision Jemena Gas Networks 2015–20, Attachment 3: Rate of return*, November 2014; AER, *Draft decision ActewAGL 2015–19, Attachment 3: Rate of return*, November 2014.

In our recent draft decisions,<sup>50</sup> we were satisfied that the Sharpe–Lintner Capital Asset Pricing Model (SLCAPM) stands out as the superior model for our purposes. We therefore adopted it as the foundation model. The SLCAPM is estimated by adding to the risk free rate to the product of the equity beta and market risk premium (MRP).

Our approach is to estimate the risk free rate based on market conditions that prevail as close as possible to the commencement of the regulatory control period.

Our point estimate for equity beta is 0.7 and MRP is 6.5 per cent, resulting in an equity risk premium of 4.55 per cent.

The critical allowance for an equity investor in a benchmark efficient entity is the allowed equity risk premium over and above the estimated risk free rate at a given time. In our November 2014 draft decisions, we compared our 4.55 per cent ERP with a range of other information. We were satisfied that our SLCAPM foundation model return on equity estimate is a reasonable estimate of efficient equity finance costs.

Energex proposed an equity beta of 0.91 and MRP of 7.57 per cent respectively in applying a foundation model approach.<sup>51</sup> Ergon Energy proposed an equity beta of 0.82 with an MRP of 7.57 per cent under its multi model approach, but submitted that if its approach is not acceptable then an equity beta of 0.91 should be applied.<sup>52</sup>

### 5.3 Return on debt

Both Energex and Ergon Energy have departed from the guideline, on some matters, to estimate the return on debt. Both have used a benchmark credit rating of BBB, rather than BBB+. Ergon Energy also used a weighted trailing average rather than a simple average, in relation to the new trailing average portfolio approach. However, in other respects, Energex's and Ergon Energy's proposals are consistent with the guideline. This includes that both distributors proposed transitional arrangements, consistent with the guideline, in moving from the old to the new regulatory approach for debt.

#### Approach

To estimate the return on debt, the guideline proposes a ten year trailing average portfolio approach, with annual updates, after a period of transition. Our proposed transitional arrangement recognises the importance of transitioning from one benchmark approach to another benchmark approach. Under our proposed transitional arrangement, we would set 100 per cent of the allowed return on debt for the first year of the 2015–20 period based on current observed corporate bond yields. For the second year (2016–17), we would set 90 per cent of the allowed return on debt based on then-current corporate yields. For the third year we would set 80 per cent of the allowed return based on then-current corporate yields. And so on.

After ten years (covering two regulatory control periods), then-current observed bond yields would no longer impact at all on the allowed return on debt. For each of those ten years, progressively more of the allowed return on debt would be based on our proposed ten year trailing average portfolio approach. After the ten year transition period, 100 per cent of the allowed return on debt would be based on the ten year trailing average portfolio.

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<sup>50</sup> For Ausgrid, Endeavour Energy, Essential Energy, published in November 2012; [www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements](http://www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements)

<sup>51</sup> Energex, *Regulatory proposal*, p. 165.

<sup>52</sup> Ergon Energy, *Regulatory proposal*, pp.134, 137.

## Implementation

The guideline also sets a benchmark credit rating of BBB+, based on the median credit rating for a sample of Australian utilities from 2002 to 2012. Each of the distributors has departed from the guideline in regard to the benchmark credit rating. They have proposed to apply a benchmark credit rating of BBB. It is not clear what impact (if any) the proposed change in credit rating would have; given the two possible data series' providers (the RBA and Bloomberg) both publish broad BBB rated data series.

In the guideline we proposed to apply the published yields from an independent third party data service provider for estimating the prevailing return on debt for each service provider during the averaging period. In April 2014, we released an issues paper seeking submissions on which third party data service provider we should use to estimate the return on debt.<sup>53</sup> In our November 2014 draft decisions on the proposals from other service providers, we formed a position on the choice of third party data series.<sup>54</sup> We decided to annually update the trailing average portfolio return on debt, over the service provider's averaging period, using a simple average of:

- the RBA data series (specifically, the RBA broad-BBB rated 10 year curve), and
- the Bloomberg BVAL data series (specifically, the Bloomberg broad-BBB rated 7 year BVAL curve, where available, and otherwise the Bloomberg BBB rated 5 year BVAL curve).

We adopted this position because we were not satisfied that either data series is clearly superior to the other. This position is supported by advice from our expert, Lally.<sup>55</sup> A simple average of two curves in these circumstances is also consistent with the Tribunal decision in ActewAGL where the Tribunal concluded that:

if the AER cannot find a basis upon which to distinguish between the published curves, it is appropriate to average the yields provided by each curve, so long as the published curves are widely used and market respected.<sup>56</sup>

Further, our draft decision for the other service providers was also to make certain adjustments to the RBA and BVAL data series.<sup>57</sup> These adjustments were to match the return on debt with benchmark 10 year debt term, to enable the data series to be implemented over the service providers' averaging periods, and to enable the change in revenue resulting from the annual debt update to occur via the automatic application of a formula that is specified in the determination, consistent with the rules.<sup>58</sup>

## 5.4 Value of imputation credits

Both Energex and Ergon Energy have proposed a value of imputation credits of 0.25, which is lower than the 0.5 proposed in our guideline. The value proposed by Energex and Ergon Energy is determined as the product of:

- a distribution rate of 0.7, consistent with our guideline

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<sup>53</sup> AER, *Return on debt: Choice of third party data service provider – Issues paper*, April 2014.

<sup>54</sup> [www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements](http://www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements)

<sup>55</sup> Lally, *Implementation issues for the cost of debt*, pp.3-6.

<sup>56</sup> In this decision, the issue before the Australian Competition Tribunal was the choice between the Bloomberg BFVC and the CBASpectrum curve, neither of which are currently published. See: *Application by ActewAGL Distribution [2010] ACompT4*, 17 September 2010, paragraph 78.

<sup>57</sup> For the RBA curve, our draft decision was to interpolate the monthly data points to produce daily estimates, to extrapolate it to an effective term of 10 years, and to convert it to an effective annual rate. For the BVAL curve, our draft decision is to extrapolate it to 10 years using the spread between the extrapolated RBA 7 and 10 year curves, and to convert it to an effective annual rate.

<sup>58</sup> NER, cl. 6.5.2(l).

- a utilisation rate of 0.35, which is lower than the 0.7 in our guideline.<sup>59</sup>

Under the Australian taxation system, investors can receive an 'imputation credit' (known as 'gamma' in this context) for income tax paid at the company level. For investors that meet certain eligibility criteria, this credit can be used to offset their tax liabilities. Imputation credits are a benefit to investors in addition to any cash dividend or capital gains from owning shares.

The rules account for the value of imputation credits through an adjustment to the company income tax building block allowance. The lower the value of imputation credits, the larger the revenue allowance for the distributor. The guideline proposes that the value of imputation credits would be estimated as a market-wide parameter, rather than estimating this on an industry or business specific basis. Under the guideline, it would be determined as the product of:

- a distribution rate (referred to in our guideline as the 'payout ratio'), which represents the proportion of imputation credits generated by the benchmark entity that is distributed to investors
- a utilisation rate, which is the extent to which investors can use the imputation credits they receive to reduce their tax or to get a refund.

The distribution rate would be estimated using the cumulative payout ratio approach. This approach uses ATO tax statistics to calculate the proportion of imputation credits generated (via tax payments) that has been distributed by companies since the start of the imputation system. The utilisation rate would be estimated using the body of relevant evidence with regards to its strengths and limitations, checked against a range of supporting evidence.

In the guideline, our assessment of this evidence produced an estimate of 0.7 for the utilisation rate. The guideline therefore proposed an estimate of 0.5 for the value of imputation credits, based on a distribution rate of 0.7 and a utilisation rate of 0.7.

In our November 2014 draft decisions on the proposals from other service providers, we broadly maintained the approach set out in the guideline to the value of imputation credits, but re-examined the relevant evidence and estimates.<sup>60</sup> Based on expert advice, we also clarified our definition of the utilisation rate as the utilisation value to investors in the market per dollar of imputation credits distributed. This re-examination, in addition to new evidence and advice considered since the guideline, led us to depart from the 0.5 value of imputation credits we proposed in the guideline. Instead, we chose a value for imputation credits of 0.4 from within a range of 0.3 to 0.5. Importantly, we considered that a value of imputation credits of 0.4 provides service providers with a reasonable opportunity to recover at least their efficient corporate tax costs, and that this value is consistent with the building block framework embedded in the rules.

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<sup>59</sup> Energex actually referred to the utilisation rate as 'the value of distributed imputation credits to investors who receive them', and labelled this parameter the Greek letter 'theta'. Ergon Energy referred to the utilisation rate as 'the value of imputation credits', and also labelled the parameter theta. We intend to discuss the alternative labelling and interpretations of the utilisation rate in our draft decision.

<sup>60</sup> [www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements](http://www.aer.gov.au/networks-pipelines/determinations-and-access-arrangements)

## 6 Consumer engagement

Energex and Ergon Energy have submitted their consumer engagement strategies and descriptions of the feedback they received from consumers and other stakeholders. Consumer engagement is an important issue for our distribution determination. Our expectations of network service providers, such as Energex and Ergon Energy, are set out in a Consumer Engagement Guideline we published in December 2013.<sup>61</sup>

As required by the rules, we will have regard to the nature of consumer engagement undertaken and the outcomes of that engagement in considering the proposals put to us by network service providers.<sup>62</sup> We will consider 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

We will make our assessment on a case-by-case basis drawing on the distributor's proposal and submissions from the Consumer Challenge Panel<sup>63</sup> and other stakeholders. We will also have regard to the extent to which each distributor's opex and capex proposals reflect consumer concerns.<sup>64</sup>

### Questions

Do you consider Energex and Ergon Energy have adopted practices set out in the Consumer Engagement Guideline to build genuine consumer engagement across all business activities?

Do you consider the proposals from Energex and Ergon Energy reflect the engagement they had with you and issues you raised with them? If they did not agree with consumer views, did they explain why?

Did Energex and Ergon Energy provide you with options and scenarios for service and price trade-offs?

### 6.1 Distributors' consumer engagement

This section summarises the consumer engagement strategies and activities described by Energex and Ergon Energy in their regulatory proposals. We consider this is a valuable resource for readers to get a sense of the distributors' consumer engagement approaches. However, we also encourage you to review the regulatory proposals' consumer engagement materials and submit your views.

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<sup>61</sup> AER, *Consumer engagement guideline for network service providers*, November 2013.

<sup>62</sup> 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.

<sup>63</sup> We have established an advisory panel including consumer advocates that advises us on how network service providers' proposals meet consumer expectations. The Consumer Challenge Panel assists us to make better regulatory determinations by providing input on issues important to consumers.

<sup>64</sup> NER, cl. 6.5.6(e)(5A) and 6.5.7(e)(5A).

## Energex

Energex submitted it undertakes a range of consumer engagement activities as part of its normal operations.<sup>65</sup> Energex also submitted it initiated an additional consumer consultation program, "connecting with you", specifically to inform its 2015–20 regulatory proposal. The program included:

- understanding key stakeholder expectations and service preferences
- use of quantitative online surveys
- qualitative research, including through focus groups, large customer interviews and stakeholder meetings
- issuing fact sheets and holding information sessions.<sup>66</sup>

Energex submitted that its consumer feedback provided support for the maintenance of current service standards. Also, that in areas of currently poor service the level of service should be improved. However, Energex also noted consumers do not want to see further price rises.<sup>67</sup>

## Ergon Energy

Ergon Energy submitted its engagement program began formally in July 2013:<sup>68</sup> Ergon Energy also submitted it engaged with residential and business consumers, its customer council, consumer advocacy groups, community leaders, electricity retailers and other industry participants like real estate developers.<sup>69</sup> Ergon Energy's engagement activities included:

- listening sessions with 43 consumers
- online surveys
- 40 Board/senior leadership regional presentations addressing around 5000 consumers,
- research into service and cost trade-offs involving 1,822 residents and 513 businesses
- website information.<sup>70</sup>

Ergon Energy submitted that its consumers provided a very clear message—they seek relief from rising prices. Ergon Energy further submitted that its consumers are not willing to pay for further improvement in the reliability of electricity supply. Ergon Energy noted that consumers impacted by service interruptions see both network prices and service levels as critical.<sup>71</sup>

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<sup>65</sup> Energex, *Regulatory proposal, Appendix 6 – Summary of Energex's existing engagement activities*, October 2014.

<sup>66</sup> Energex, *Our five year future plan – regulatory proposal overview 2015–2020*, pp. 12 to 15 outline some of customer engagement research insights. Also see: Energex, *Regulatory proposal, Chapter 4 –customer engagement*, October 2014, pp. 43–53.

<sup>67</sup> Energex, *Regulatory proposal, Chapter 4 –customer engagement*, October 2014, pp. 43–53.

<sup>68</sup> Ergon Energy, *Regulatory proposal supporting documentation – Informing our plans, our engagement program*, October 2014, p. 7.

<sup>69</sup> Ergon Energy, *Regulatory proposal supporting documentation – Informing our plans, our engagement program*, October 2014, p. 10.

<sup>70</sup> Ergon Energy, *Regulatory proposal supporting documentation – Informing our plans, our engagement program*, October 2014, pp. 11–12.

<sup>71</sup> Ergon Energy, *Regulatory proposal supporting documentation – Informing our plans, our engagement program*, October 2014, p. 16.

## 6.2 Consumer engagement guideline

To assist service providers, such as Energex and Ergon Energy, we developed a consumer engagement guideline for network service providers.<sup>72</sup> The guideline centres on:

- best practice principles to drive consumer engagement
- a commitment from service providers to continuously improve engagement across all business operations on issues that are significant to the business and its consumers.

The guideline is not prescriptive. Rather, it places the onus on the distributors to develop consumer engagement strategies and activities that best suit their business.

## 6.3 Our own consumer engagement

For the last 12 months we have engaged with consumer and other stakeholder groups, the Qld distributors and the Qld Government about the 2015–20 electricity determinations. We have heard strong views about the adverse impact on consumers of electricity price increases during the 2010–15 period. It is clear that consumers and stakeholder groups are seeking price relief and greater transparency from the distributors. Our Consumer Challenge Panel has been engaging with consumer groups and stakeholders and advising us on issues it considers relevant to consumers.

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<sup>72</sup> AER, *Consumer engagement guideline for network service providers*, November 2013.

## 7 Other issues

This chapter discusses some additional key issues for this reset which do not fall neatly into the previous chapters on capex, opex, rate of return and consumer engagement:

- metering
- cost pass throughs
- public lighting.

### 7.1 Metering

In our Framework and Approach paper,<sup>73</sup> published in April 2014, we proposed to reclassify standard metering services for residential and small business consumers (type 5 and 6 meters) as alternative control, from standard control. This means that consumers using these metering services will pay for them, rather than these costs being included in standard network charges paid by all consumers.

Our reclassification of type 5 and 6 metering services is intended to facilitate the competitive provision of metering services, including new smart meters. This is one component of a broader range of reforms to the way metering services are provided, currently being considered under a rule change proposal, initiated by the COAG Energy Council, by the Australian Energy Market Commission. The goal of these reforms is to remove the distributors' existing monopoly on metering services and to enable a range of new services, both inside the consumer's home or business and for the distributors themselves. Smart meters will also allow for more cost reflective pricing than the traditional type 5 and 6 meters.

We consider a valuable outcome of more efficient pricing structures enabled by smart meters will be to reduce pressure on the distributors to build additional infrastructure to meet high demand periods. Instead, consumers and distributors will be better able to manage electricity demand to optimise existing network assets, reducing the costs that consumers would otherwise be asked to pay for.

As a standard control service, the value of a type 5 or 6 meter is included in the distributors' RAB. This value, or 'cost' from the perspective of the consumer, is recovered from all consumers over time, rather than up front. When a consumer switches from a traditional type 5 or 6 meter to a new smart meter, the value of the meter will be removed from the RAB. That is, the distributor will earn no more revenue to cover the remaining value (cost) of that meter. Consequently, the distributor may be out of pocket.

To address this issue, Energex and Ergon Energy have proposed exit or transfer fees for consumers that switch to a smart meter. The proposed fees are intended to cover either both the cost of the meter and administrative costs associated with its removal (exit fee), or just the cost of the meter (transfer fee). Energex proposed a range of fees up to \$324 per meter.<sup>74</sup> Ergon Energy proposed a number of fees up to \$166.<sup>75</sup>

Our initial view is that the exit or transfer fees proposed by Energex and Ergon Energy are likely to inhibit development of effective competition in the provision of metering services. This is because they

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<sup>73</sup> AER, *Final framework and approach for Energex and Ergon Energy – regulatory control period commencing 1 July 2015*, April 2014.

<sup>74</sup> Energex, *Regulatory proposal*, p. 280.

<sup>75</sup> Ergon Energy, *Regulatory proposal*, p. 51.



will be a disincentive for consumers to switch to smart meters. In turn, the potential benefits of using smart meters will be less likely to emerge.

We are working with Energex and Ergon Energy, through this determination process, to develop an approach allowing them to recover their metering related costs without establishing a significant barrier to the adoption of smart meters. We invite consumers and other stakeholders to submit views to us, to inform our preliminary decision.

## 7.2 Cost pass throughs

The rules permit the distributors to apply to us, during a regulatory period, for their prices to be adjusted because an unexpected and material cost arises or, in some cases, if actual costs are materially different to the allowances included in our original determination.<sup>76</sup> While cost pass throughs may be opex in nature, they may also be capex or a combination of different cost categories. Pass throughs are only permitted if they are for events listed in the distributors' distribution determinations or defined in the rules. Once a distribution determination has been finalised, we are required to approve a cost pass through application from a distributor if it satisfies the relevant requirements in our determination and the rules.

A number of pass through events are already defined by the rules:

- regulatory change event
- service standard event
- tax change event
- retailer insolvency event.

For the 2015–20 regulatory period, both Energex and Ergon Energy have jointly proposed additional pass throughs for:

- insurance cap event
- natural disaster event
- insurer event.

In addition to the nominated pass through events listed above, both Energex and Ergon Energy have separately nominated the below:

- Energex<sup>77</sup>
  - terrorism event
  - smart meter event.
- Ergon Energy<sup>78</sup>
  - retail separation event

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<sup>76</sup> NER, cl. 6.6.1.

<sup>77</sup> Energex, *Regulatory proposal*, p. 228.

<sup>78</sup> Ergon Energy, *Regulatory proposal*, p. 39.

- isolated networks separation event.

We seek your views on the pass through events nominated by the distributors. In particular, should they be recovered as part of a cost pass through if such events occur, or is it more appropriate for these potential impacts to be reflected in the distributors' allowances. Alternatively, should the distributors manage the risk of these events using their existing resources.

## 7.3 Public lighting

Energex and Ergon Energy provide public lighting services (including street lighting) in their respective service areas, predominantly to local government councils. Public lighting is classified as an alternative control service. The elements of the prices charged by the distributors to local councils for public lighting services will be set through our distribution determination process. Based on our determination, the distributors calculate the public lighting charges billed to local councils.

Through our consumer engagement activities, local councils have expressed concerns about the public lighting services they receive. In particular, councils are concerned about the prices they are paying for public lighting and the level of transparency around how those prices are calculated.

We note that both Energex and Ergon Energy have now published their public lighting price (tariff) models, setting out how their public lighting prices are calculated. They have also included public lighting proposals in their regulatory proposals.

We encourage stakeholders to consider the public lighting related material provided by the distributors in their regulatory proposals and the published tariff models. We look forward to hearing stakeholder views, to inform our preliminary determination.

## 8 Interrelationships between components of our decision

The NEL requires us to specify how the individual components of our decision relate to each other and how we have taken those interrelationships into account in making our decision. 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.

To assist you in providing us with submissions on the interrelationships inherent in the distributors' regulatory proposals, this chapter describes the building block model and outlines some of the interrelationships we are likely to take into account.

### Question

How should we balance the interrelationships between building block components when making our decision on the distributors' regulatory proposals?

### 8.1 The building block model

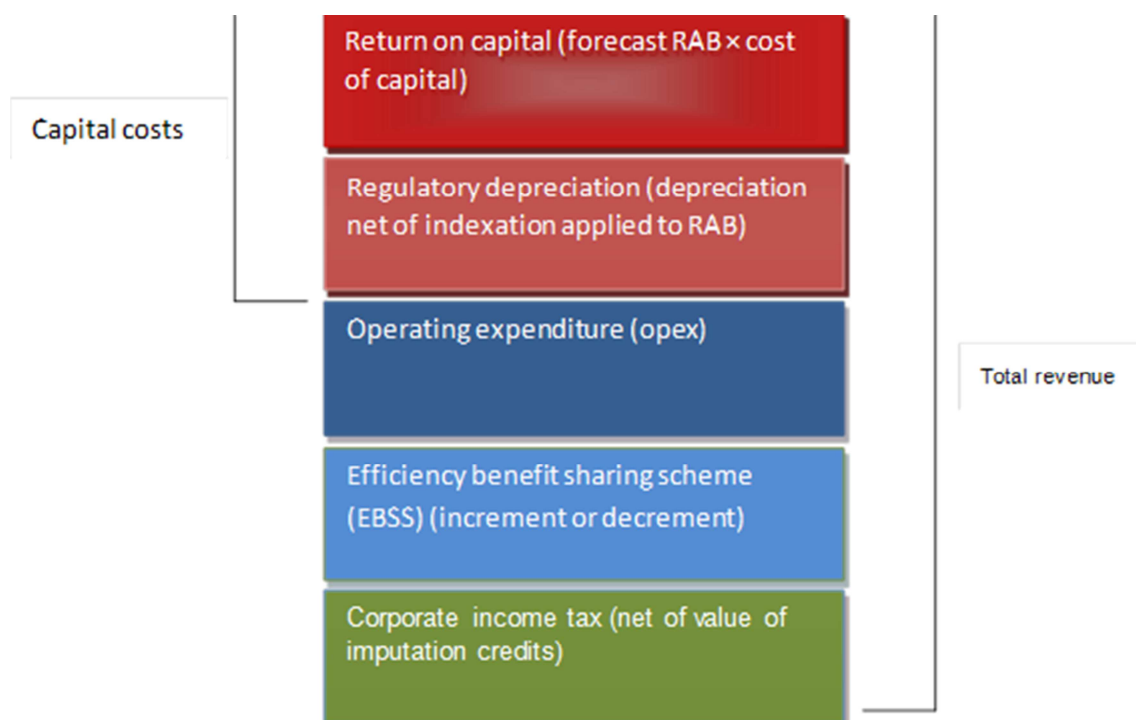
If we do not accept the distributors' revenue proposals, we must ourselves determine the efficient cost of providing distribution services, subject to the requirements of the rules. To do this, we assess the total revenue required to provide distribution services for each year of the period. In accordance with the rules, we use the building block model to determine the annual revenue requirement. The underlying cost elements include:

- a return on the regulatory asset base (return on capital)
- depreciation of the regulatory asset base (return of capital)
- opex
- increments or decrements resulting from the efficiency benefit sharing scheme (EBSS)
- the estimated cost of corporate income tax.

Our assessment of capex directly affects the size of a distributor's asset base and therefore the return on capital and return of capital building blocks.

Figure 17 below illustrates the building block model.

**Figure 17 The building block approach to determining regulated revenues**



## 8.2 Interrelationships between building block components

In some cases, the separate building block components may be substitutes, so that increasing one may lead to decreasing another. In other cases, increasing one component will increase another. There may not be a single optimal combination. Rather, several combinations may provide an efficient level of revenue. Below, we describe some of the interrelationships we consider may be important to our assessment of the distributors' proposals.

### Repair or replace assets

Maintaining existing assets incurs opex costs. However, if those assets are replaced instead of being maintained, the distributor incurs capex costs. The decision to repair or replace assets can affect ongoing opex costs, in that newer assets may require less maintenance than older assets.

### Building assets increases the return on capital and depreciation

The more capex investment undertaken by a distributor, the larger its future return on capital and depreciation allowance. This is because capex contributes to the size (value) of a distributor's asset base. The return on capital is equal to the rate of return multiplied by the value of the distributor's asset base. So the larger the asset base, the larger the dollar amount return on capital and therefore how much revenue they are allowed to recover. In the same way, the distributor's depreciation allowance becomes larger in proportion to the size of the asset base being depreciated.

### More assets require more maintenance

Depending on the type of capex investments made by a distributor, additional investment may create need for more opex spending. This is because, in principle, a large asset base requires more maintenance than a small asset base. This effect may be offset by capex investment that creates operational efficiencies, or avoids the increasing opex required to extend the operating life of ageing assets, as described above.

## Incentive schemes and revenue allowances

Schemes to provide the distributors with incentives to become more efficient, such as the EBSS, affect the revenue allowances we determine for capex and opex. For example, by seeking to maximise its EBSS payment, a distributor may uncover efficiencies in its maintenance activities. In the short term, the distributor is allowed to retain the savings it achieved. But in the longer term, the savings reduce the distributors' opex allowance, reducing prices. Because capex spending can either increase or decrease the need for opex costs to be incurred, the EBSS incentive may also influence both short and long term capex allowances. Other incentive schemes, such as the service target performance incentive scheme, target capex more directly.

A range of further interrelationships exist within the building block elements, where our decision on technical variables influence one or more of the building blocks themselves. These include:

- the economic life of assets — affects return on capital, capex, opex
- step changes — affects capex, opex, incentive schemes, pass throughs
- base year adjustments — affects opex, capex, incentive schemes
- forecast inflation — affects all forecasts
- related party transactions — affects capex, opex.

## A Background to our assessment

This appendix provides information about us, the distributors and the regulatory framework that we administer.

### A.1 The Australian Energy Regulator

We are Australia's national energy market regulator and an independent statutory authority. Our functions, set out in the NEL and rules, mostly relate to energy markets in eastern and southern Australia. These functions include:

- setting the prices charged for using energy networks (electricity poles and wires and gas pipelines) to transport energy to consumers
- monitoring wholesale electricity and gas markets so suppliers comply with the legislation and rules, and taking enforcement action where necessary
- publishing information on energy markets, including the annual State of the Energy Market report and more detailed market and compliance reporting, to assist participants and the wider community
- assisting the Australian Competition and Consumer Commission with energy-related issues arising under the Competition and Consumer Act, including enforcement, mergers and authorisations.

The NEL and rules provide the legal framework under which we operate. Chapter 6 of the rules contains timelines and processes for the regulation of electricity distribution businesses. It provides that regulated distribution businesses must periodically apply to us to assess their revenue. Typically, this happens every five years. The application, or revenue proposal/, starts a process often referred to as a revenue reset, or simply a 'reset'.

We are required to exercise our functions in a manner that will advance the National Electricity Objective (NEO). The NEO in turn is supported through the revenue and pricing principles and the various objectives, criteria and elements within the rules. The NEO is:<sup>79</sup>

...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—

- (a) price, quality, safety, reliability and security of supply of electricity; and
- (b) the reliability, safety and security of the national electricity system.

We consider that the NEO is most likely to be advanced where consumers are offered a reasonable level of service at the lowest sustainable price. In most industries, this outcome is achieved through the operation of competition. However, in the electricity network industry the usual competitive disciplines do not operate.

The electricity network businesses are natural monopolies and the products they offer are essential services for most consumers. Consequently, in an uncompetitive environment, consumers have little choice but to accept the service quality and price the distributors offer.

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<sup>79</sup> NEL, s.7.

The NEL and rules aim to reflect the competitive process 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 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.<sup>80</sup> 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.<sup>81</sup> 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 required to adequately maintain the appropriate quality and level of service, creating longer term problems in the network.<sup>82</sup> This can have adverse consequences for safety, security and reliability of the network. We would like to hear views on how the NEO is best reflected in our decision.

## A.2 Who are the distributors?

The electricity supply chain begins with a wholesale market in which generators produce electricity and sell it through a central dispatch process. The high voltage transmission network transfers electricity over long distances from where it is generated to where consumers need it. The distributors' networks connect the high voltage transmission network to consumers. Distribution networks criss-cross urban and regional areas to provide electricity to every electricity consumer.

### Energex

Energex is a Qld Government owned corporation that owns, operates and manages the electricity distribution network in south east Qld. In addition to Brisbane, Energex services the Gold Coast, Sunshine Coast and Ipswich. Energex has around 1.4 million individual connections to its network, servicing around 3.2 million people. While much of Energex's service area is metropolitan or urban, it does also cover regional areas. However, its customer density per kilometre of network is much higher than for Ergon Energy.

### Ergon Energy

Ergon Energy is a Qld Government owned corporation that owns, operates and manages the electricity distribution network outside of south east Qld. Ergon Energy's service area extends from the boundary of Energex's service area to the far north and west of Qld. Approximately 70 per cent of Ergon Energy's service area is considered rural. Ergon Energy's network has relatively low customer density.

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<sup>80</sup> *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.

<sup>81</sup> NEL, s. 7A(7).

<sup>82</sup> NEL, s. 7A(6).

## A.3 The regulatory framework

We must assess the distributors' regulatory proposals under version 58 of the rules with the modifications required by the relevant transitional provisions in chapter 11 of the rules.<sup>83</sup> Version 58 is available at the Australian Energy Market Commission (AEMC) website.<sup>84</sup> Following changes made to the rules by the AEMC in 2012, 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.<sup>85</sup> The resulting guidelines support our decision making framework as set out in section 16 of the NEL.<sup>86</sup> Our Better Regulation guidelines are:

### **Expenditure forecast assessment guideline**

Assessing expenditure proposals from businesses.

### **Rate of return guideline**

Determining the allowed rate of return businesses earn on their investments.

### **Expenditure incentives guideline**

Creating the right incentives to encourage efficient spending by businesses.

### **Consumer engagement guideline for network service providers**

Implementing consumer engagement strategies that are effective for all stakeholders.

### **Shared asset guideline**

Sharing the revenue networks earn from shared assets with consumers.

### **Confidentiality guideline**

Managing confidential information for an effective regulatory determination process.

The Better Regulation program was designed to be an inclusive process that provided an opportunity for all stakeholders to be engaged.<sup>87</sup> The extent of our consultation was unprecedented for the AER. This was very important for testing our views and hearing from the full range of stakeholders. Our exhaustive 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.<sup>88</sup>

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

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<sup>83</sup> NEL, cl. 11.60 and 11.65.

<sup>84</sup> [www.aemc.gov.au/Australias-Energy-Market/Market-Legislation/Relevant-Legislation-Electricity](http://www.aemc.gov.au/Australias-Energy-Market/Market-Legislation/Relevant-Legislation-Electricity)

<sup>85</sup> AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

<sup>86</sup> See our website: [www.aer.gov.au/Better-regulation-reform-program](http://www.aer.gov.au/Better-regulation-reform-program)

<sup>87</sup> AER, *Overview of the Better Regulation reform package*, April 2014, pp. 4 and 7–13.

<sup>88</sup> 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](http://www.aer.gov.au/node/19166).



program.<sup>89</sup> Consumers and network service providers also made written submissions on our draft guidelines and explanatory statements, responded to advice from our experts and provided their own consultant reports.

In the process established by the rules, the distributors have the first opportunity to propose a price/service offering. The distributors' application, or regulatory proposal, starts a process often referred to as a revenue reset, or simply a 'reset'. We will assess that proposal against the NEO and the rules to form a view on whether a distributor's proposal is in the long term interests of consumers. Where it is not, we will not accept the proposal, and instead substitute our own decision.

Because this is an intrusive process we exercise our role with care and diligence. We consult broadly and test our views, employing approaches that are widely accepted and carefully considered, such as those articulated in the guidelines.

### Transitional arrangements applicable to these resets

The AEMC recognised that there was a need to put in place transitional arrangements for the current round of resets. Under the transitional arrangements applying to Queensland distributors for the 2015-2020 regulatory control period, commencement of the AER's revenue determination process is delayed by five months.

The rules require us to publish the Queensland distributors' regulatory proposals, invite submissions and hold a public forum on the regulatory proposals and the AER's proposed negotiated distributions service criteria.<sup>90</sup> Although they do not require us to publish an issues paper, we have decided to publish this issues paper in the interests of transparency and to assist stakeholder input to the process.

At the same time that we publish our preliminary determinations for the 2015-20 period in April 2015, we are required to invite submissions on the revocation and substitution of those determinations.<sup>91</sup> Distributors may make a submission in the form of revisions to the regulatory proposal.<sup>92</sup> Although we are not required to do so under the transitional arrangements, we will hold a public forum following the publication of our preliminary determinations. We also propose to provide stakeholders with the opportunity to make submissions on any revised regulatory proposals submitted by the distributors, before we revoke the preliminary determinations and make our final determinations in October 2015 in substitution for them.

## A.4 Our framework and approach

We released our Framework and Approach (F&A) in April 2014.<sup>93</sup> This set out our intended approach to parts of the regulatory framework, such as service classification. In terms of our classification decisions, in summary we may:

- classify a service so that the distributor may recover related costs from all consumers (standard control)
- classify a service so that the user benefiting from the service pays (alternative control)

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<sup>89</sup> AER, *Overview of the Better Regulation reform package*, April 2014, pp. 20–21.

<sup>90</sup> NER, cl. 6.9.3(a) and 11.60.3(b)(3)(ii).

<sup>91</sup> NER, cl. 11.60.4(a).

<sup>92</sup> NER, cl. 11.60.4(b).

<sup>93</sup> [www.aer.gov.au/node/20187](http://www.aer.gov.au/node/20187); [www.aer.gov.au/node/20186](http://www.aer.gov.au/node/20186)

- allow consumers and distributors to negotiate the provision and price of some services—we will arbitrate should negotiations stall (negotiated distribution service)
- not classify a service—we have no regulatory control over this service or the prices charged by the distributor (unclassified service).

Standard control services represent the large majority of a distributor's revenue, reflecting the integrated nature of an electricity supply network. The distributors recover the cost of providing standard control services from all electricity consumers through standard network charges—known as Distribution Use of System (DUoS) charges. It is the total cost of providing standard control services that this issues paper predominantly relates to. Services classified as alternative control are separately billed to individual electricity consumers.

Figure 18 below shows our proposed service classifications for the 2015–20 period. We may only change our proposed classifications if we consider unforeseen circumstances arise.<sup>94</sup> Our classifications are consistent with those for the 2010–15 period, with two important exceptions:

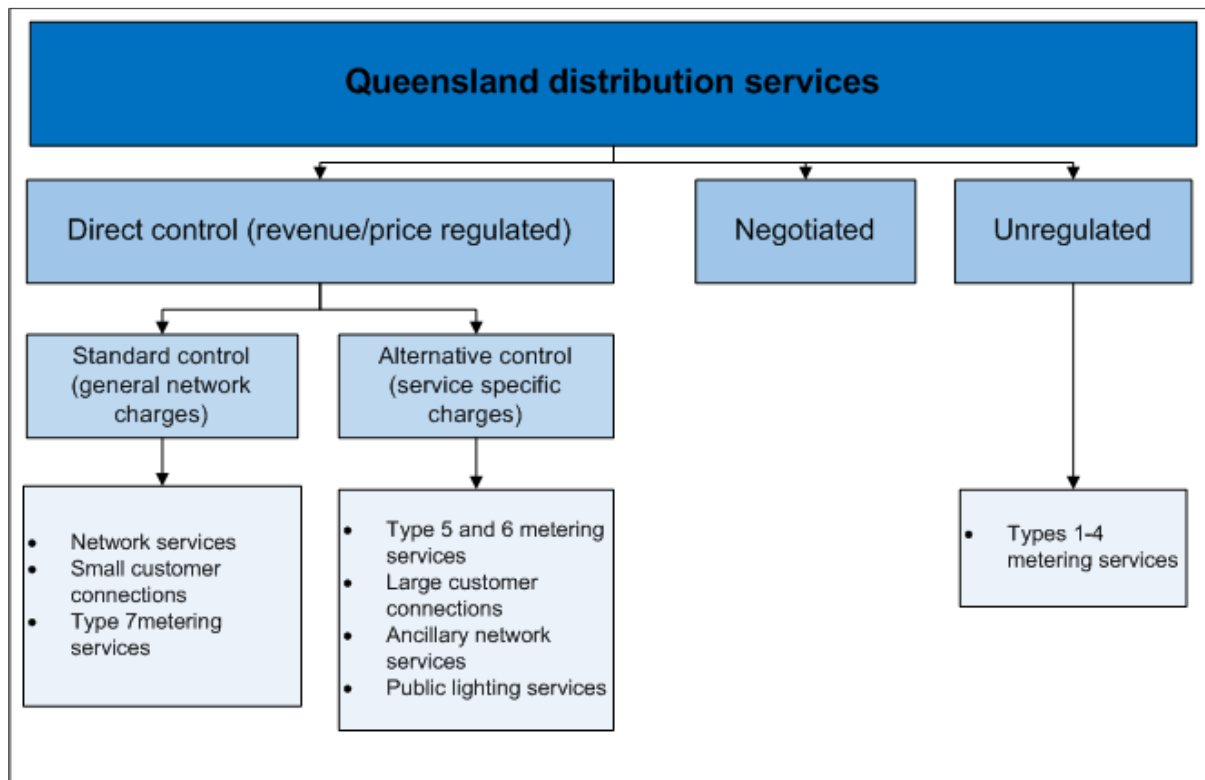
- type 5 and 6 metering services (simple accumulation and basic time of use meters) are reclassified as alternative control, from standard control
- ancillary network services have also been reclassified as alternative control, from standard control.

These changes mean the costs of providing these services will now be excluded from the distributors' DUoS charges. In future they will be recovered from specific consumers requiring those services, rather than from all consumers.

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<sup>94</sup> NER, cl. 6.21.3(b).

**Figure 18 AER proposed 2015–20 service classifications for the Qld distributors**



Source: AER