

9.01

# Application of incentive schemes

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# 1 OVERVIEW

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Ausgrid supports the Australian Energy Regulator's (AER's) proposal to apply the various expenditure, performance and demand management incentive schemes during the 2019-24 regulatory period. We do not propose any significant divergences from the AER's position on the application of these schemes, as set out in its Framework and Approach (F&A) paper.

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An important element of the regulatory framework is the application of various incentive schemes to distribution network service providers (DNSPs). The purpose of these schemes is to balance the incentives DNSPs have to undertake efficient capital and operating expenditure across a regulatory period while maintaining appropriate levels of reliability and customer service, as well as considering demand management options. The benefits that flow from more efficient investment and operation of the network are shared with customers via lower prices in future regulatory periods.

The following incentive schemes may be applied to Ausgrid:

- Efficiency benefit sharing scheme
- Capital expenditure sharing scheme
- Service target performance incentive scheme
- Demand management incentive scheme
- Small scale incentive scheme.

The AER is required to publish its proposed approach to incentive schemes in its framework and approach paper.<sup>1</sup>

The National Electricity Rules (NER) require that our proposal contain a description, including relevant explanatory material, of how we propose any incentive scheme that has been specified in the framework and approach paper should apply.<sup>2</sup> The Regulatory Information Notice (RIN) also places a number of requirements on Ausgrid relating to our proposals regarding incentives schemes.

This attachment sets out, for each incentive scheme, the relevant rule requirements and our proposed application of the incentive schemes. Together, the incentive schemes will help to drive efficiencies and improvements to our reliability and customer service that will ultimately benefit our customers.

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<sup>1</sup> NER clause 6.8.1(b)(2).

<sup>2</sup> NER clause s6.1.3.

## 2 EFFICIENCY BENEFITS SHARING SCHEME

We propose the Efficiency Benefits Sharing Scheme (EBSS) apply to Ausgrid for the 2019-24 regulatory control period. We propose two cost categories be excluded from the calculation of the reward/penalty: debt raising costs and the demand management incentive allowance. This is consistent with the AER's application of the scheme to other DNSPs.

### 2.1 Overview

The NER require the AER to publish an EBSS.<sup>3</sup> The EBSS provides DNSPs with a continuous incentive to pursue efficiency improvements in its operating expenditure and provide a fair sharing of these between a distributor and network users. Customers also benefit from improved efficiencies through lower regulated prices in future regulatory control periods.

The EBSS works by providing Ausgrid with a reward (or penalty) of 30% of any opex underspend (or overspend) during the regulatory control period, with the remaining 70% being returned to (or recovered from) customers in the form of lower (or higher) prices.

The EBSS does not currently apply to Ausgrid. In its final decision for the 2015-19 regulatory period, the AER noted that the EBSS is intrinsically linked to the use of a revealed cost forecasting approach for opex, and that where a revealed cost approach is not used for future periods, there is not a strong reason to subject expenditure to the current EBSS. The AER further stated:<sup>4</sup>

*"We consider Ausgrid will already face an incentive to make efficiency improvements while its actual opex is more than that of a benchmark efficient service provider. We do not need to subject any expenditure to an EBSS to further strengthen its incentives."*

### 2.2 Rule requirements

The Rules set out a clear process on how the AER is to make a constituent decision on how an applicable EBSS is to apply to a DNSP for a regulatory control period. In the sections below, we summarise the process prescribed under the NER:

- Under 6.6.2 of the NER, the AER must publish an EBSS for DNSPs that provides for a fair sharing between DNSPs and distribution network users of efficiency gains and losses associated with opex being less than or more than forecast opex. The most recent amended version of the EBSS is that published by the AER in November 2013 (version 2).
- The NER require that the AER set out its proposed approach to applying the current version of the EBSS in the Framework and Approach paper process.<sup>5</sup> The Framework and Approach paper published on 27 July 2017 included a description of how the AER proposes to apply the EBSS to the 2019-24 regulatory period.
- The NER require that a DNSP's regulatory proposal provides a description, including relevant explanatory material, of how the DNSP proposes any EBSS that has been

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<sup>3</sup> NER clause 6.5.8(a).

<sup>4</sup> AER, Final Decision, Ausgrid distribution determination 2015-16 to 2018-19, Attachment 9 – Efficiency benefit sharing scheme, April 2015, p9-9.

<sup>5</sup> NER clause 6.8.1(b)(2)(iv).

specified in a framework and approach paper that applies in respect of the forthcoming distribution determination should apply to it.<sup>6</sup>

- Clause 6.12.1(9) of the NER states that the AER must make a decision on how any applicable EBSS is to apply to the DNSP.
- Clause 6.3.2(a)(3) of the NER requires a building block determination to specify how any applicable EBSS is to apply.
- The building blocks used to calculate the annual revenue requirement for each regulatory year of a regulatory control period must include, amongst other things, any revenue increments or decrements for that year arising from the application of any EBSS.<sup>7</sup>
- The Regulatory Information Notice requires us to identify all cost categories proposed to be excluded from the operation of the EBSS and an explanation as to why each cost category identified should be excluded.<sup>8</sup> The RIN also requires us to explain any variation or departure from the application of any component of the EBSS as set out in the F&A paper.<sup>9</sup>

## 2.3 Application to the 2019-24 regulatory period

We consider the EBSS should apply to Ausgrid for the 2019-24 regulatory period. The AER was not clear in its Framework and Approach paper on whether they intend to apply the EBSS to Ausgrid for the 2019-24 regulatory period. The AER stated:<sup>10</sup>

*“We will decide if and how we will apply [the EBSS] in our determinations. Our determinations will take into account the information available to us at that time as to the distributors’ revealed costs and the basis on which we approve their forecast opex.”*

As discussed further in chapter 6, we have applied a base-step-trend approach to forecasting our opex for most costs, with a base year of 2017/18. This method aligns with the AER’s preferred approach to forecasting most categories of opex, as outlined in the AER’s Expenditure Forecast Assessment Guideline. It is also consistent with the AER’s view of when the EBSS should be applied. The AER noted:<sup>11</sup>

*“The EBSS is intrinsically linked to a distributor’s revealed costs. In assessing a distributor’s opex proposal, we seek to identify an efficient opex amount in the base year (the ‘revealed costs’ of the distributor), which we use to develop an alternative estimate of total opex for the 2019–24 regulatory control period...”*

*Where approved forecast opex reflects revealed costs, the application of the EBSS serves two important functions:*

1. *It removes the incentive for a distributor to inflate opex in the expected base year in order to gain a higher opex forecast for the next regulatory control period*
2. *It provides a continuous incentive for a distributor to pursue efficiency improvements across the regulatory control period.”*

<sup>6</sup> NER clause S6.1.3(3).

<sup>7</sup> NER clause 6.4.3(a)(5).

<sup>8</sup> Reset RIN Schedule 1 clause 18.

<sup>9</sup> Reset RIN Schedule 1 clause 1.7.

<sup>10</sup> AER, Framework and Approach, Ausgrid, Endeavour Energy and Essential Energy Regulatory control period commencing 1 July 2019, July 2017, p66.

<sup>11</sup> Ibid, p67.

We consider that our 2017/18 opex, adjusted for non-recurring costs<sup>12</sup> represent an efficient opex amount from which to apply a trend to forecast our opex. Since this is a revealed cost approach, we consider it is appropriate and consistent with the AER's approach to apply the EBSS.

We propose that costs that are not forecast using the base-step-trend approach, that is debt raising costs and the demand management incentive allowance, are excluded from the application of the EBSS. This is explained below.

Our stakeholders did not express any strong views on the application of the EBSS.

### 2.3.1 Cost exclusions

In deciding how the EBSS should apply, Ausgrid can propose that certain cost categories be excluded from the calculations of efficiency gains or losses when the EBSS is applied by the AER. The EBSS permits exclusions of cost categories where the AER does not use a single year revealed cost forecasting approach. This is because if such an approach is not used, a different sharing ratio may result, and there is a risk the EBSS may provide windfall gains or losses to a NSP. Excluding certain costs from the EBSS is therefore intended to better share the benefits of efficiency improvements between consumers and DNSPs, and prevent windfall gains or losses arising.

The current version of the EBSS already specifies the following adjustments that the AER will make:<sup>13</sup>

- Adjust forecast opex to add (subtract) any approved revenue increments (decrements) made after the initial regulatory determination. This may include approved pass through amounts or opex for contingent projects
- Adjust actual opex incurred in a regulatory period to add capitalised opex that has been excluded from the RAB (where there has been a change in capitalisation policy)
- Exclude categories of opex not forecast using a single-year revealed cost approach for the regulatory control period at the start of the next regulatory period where doing so better achieves the requirements of clause 6.5.8 of the NER
- Adjust for inflation.

Ausgrid agrees that these adjustments should be made in applying the EBSS.

In addition, Ausgrid nominates the cost exclusions set out in Table 1 below from the EBSS when it is applied in the 2019-24 regulatory period. We note that the AER has consistently agreed to exclude these costs for other DNSPs.

**Table 1. Proposed cost category exclusions from the EBSS**

Cost category	Reason for exclusion
Debt raising costs	Ausgrid intends to adopt the method that the AER uses to derive this cost. That is, debt raising cost will be calculated by applying a benchmark debt raising unit rate to the debt portion of our regulated asset base. Because this is not a revealed cost approach, these costs should not be subject to the EBSS.
DMIA	The DMIA is defined as part of the demand management incentive scheme and under the current arrangements any underspend must be returned to customers in full.

<sup>12</sup> See Chapter 6 of our proposal for further details.

<sup>13</sup> AER, Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, November 2013, clause 1.4.

### 2.3.2 Base year

As noted by the AER, the operation of the EBSS is intrinsically linked to opex performance over the regulatory period relative to the base year. We therefore consider that the EBSS should be calculated on that basis (i.e. measuring the 2019/20 incremental efficiency gain/loss as the incremental change from 2017/18 through to 2019/20).

## 3 CAPITAL EXPENDITURE SHARING SCHEME

We propose the Capital Expenditure Sharing Scheme (CESS) continue to apply to Ausgrid for the 2019-24 regulatory control period in its current form. We also propose that the value of the regulatory asset base at the beginning of the next regulatory period is established using forecast depreciation. This is consistent with the AER's proposed approach.

### 3.1 Overview

The NER permit the AER to develop a CESS.<sup>14</sup> The CESS provides DNSPs with a continuous incentive to undertake efficient capital expenditure throughout the regulatory control period by rewarding efficiency gains and penalising efficiency losses. Customers also benefit from improved efficiencies through lower regulated prices in future regulatory control periods.

The CESS works by providing Ausgrid with a reward (or penalty) of 30% of any capex underspend (or overspend) during the regulatory control period, with the remaining 70% being returned to (or recovered from) customers in the form of lower (or higher) prices.

A CESS currently applies to Ausgrid.

### 3.2 Rule requirements

The NER set out a clear process on how the AER is to make a constituent decision on how an applicable CESS is to apply to a DNSP for a regulatory control period. In the sections below, we summarise the process prescribed in the NER:

- Under 6.5.8A of the NER, the AER may publish a CESS that provides DNSPs with an incentive to undertake efficient capital expenditure during a regulatory control period. The most recent version of the CESS is that published by the AER in November 2013 (version 1).
- The NER require that the AER set out its proposed approach to applying the current version of the CESS in the Framework and Approach paper process.<sup>15</sup> The Framework and Approach paper published on 27 July 2017 included a description of how the AER proposes to apply the CESS to the 2019-24 regulatory period.
- The NER require that a DNSP's regulatory proposal provide a description, including relevant explanatory material, of how the DNSP proposes any CESS that has been specified in a framework and approach paper that applies in respect of the forthcoming distribution determination should apply to it.<sup>16</sup>
- Clause 6.12.1(9) of the NER states that the AER must make a decision on how any applicable CESS is to apply to the DNSP.
- Clause 6.3.2(a)(3) of the NER requires a building block determination to specify how any applicable CESS is to apply.
- The building blocks used to calculate the annual revenue requirement for each regulatory year of a regulatory control period must include, amongst other things, any revenue increments or decrements for that year arising from the application of any CESS.<sup>17</sup>

<sup>14</sup> NER clause 6.5.8A.

<sup>15</sup> NER clause 6.8.1(b)(2)(iv).

<sup>16</sup> NER clause S6.1.3(3A).

<sup>17</sup> NER clause 6.4.3(a)(5).



- The Regulatory Information Notice requires us to explain any variation or departure from the application of any component of the CESS as set out in the F&A paper.<sup>18</sup>

### 3.3 Application to the 2019-24 regulatory period

Ausgrid proposes that the mechanism for calculating the penalty or reward under the scheme be calculated in accordance with the AER's guidelines. Under the guidelines, the CESS is applied as follows:

- The AER calculates the cumulative underspend or overspend amount for the current regulatory control period in net present value terms.
- The AER applies the sharing ratio of 30% to the cumulative underspend or overspend amount to work out what the distributor's share of any underspend or overspend should be.
- The AER calculates the CESS payments taking into account the financing benefit or cost to the distributor of any underspend or overspend amounts. The AER can also make further adjustments to account for deferral of capex and ex post exclusions of capex from the RAB.
- The CESS payments are added to or subtracted from the distributor's regulated revenue as a separate building block in the next regulatory control period.

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

Our stakeholders did not express any strong views on the application of the CESS for the 2019-24 regulatory period.

#### 3.3.1 Depreciation

A key element of the overall capex incentive framework is the depreciation approach to use when a distributor's regulatory asset base (RAB) is updated from forecast capex to actual capex at the end of a regulatory period. In establishing the value of the RAB as at the beginning of the period subsequent to the 2019-24 period, i.e. as at 1 July 2024, the AER can decide either to use the depreciation on actual capex (actual depreciation) or the depreciation on forecast capex (forecast depreciation). The choice of depreciation affects the power of the incentives that apply to capital expenditure.

The AER has proposed to use the forecast depreciation approach to establish the value of the RAB as at 1 July 2019 for NSW distributors. The AER considers that this approach, in combination with the CESS, will provide sufficient incentive for the distributors to achieve capex efficiency gains over the 2014-19 period.

#### 3.3.2 Calculating the reward or penalty

We understand that the AER is still finalising the calculation of the CESS reward within its pro-forma CESS model. We propose that the CESS reward for 2019-24 is calculated consistent with the CESS model we have included in this proposal for capex over/underspend in the 2014-19 regulatory period. The details of this calculation can be found in Chapter 4 and within the attached CESS model for 2014-19 capex performance.

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<sup>18</sup> RIN clause 1.7.

## 4 SERVICE TARGET PERFORMANCE INCENTIVE SCHEME

We propose the Service Target Performance Incentive Scheme (STPIS) continue to apply, with our revenue at risk increased to  $\pm 5\%$ . Our proposed approach is broadly consistent with the AER's application. However, we propose a minor deviation to the calculation of the customer parameter target.

### 4.1 Overview

The NER require the AER to publish a national distribution STPIS.<sup>19</sup> The purpose of this scheme is to provide a financial incentive for distributors to maintain and improve service performance where it provides value to customers. This is intended to counterbalance any incentives DNSPs may have to reduce costs at the expense of reliability and customer service levels.

The AER's STPIS comprises two components:

- A service factor (s-factor) adjustment to the annual revenue allowance that rewards (or penalises) DNSPs for better (or worse) performance compared with a predetermined target for supply reliability and customer service, set by the AER
- A guaranteed service level (GSL) component whereby customers are paid if they experience a service below a predetermined level, set by the AER.

A STPIS currently applies to Ausgrid. However, the GSL component does not apply as Ausgrid remains subject to a jurisdictional GSL scheme, set out in Ausgrid's licence conditions under the Electricity Supply Act 1995 (NSW).

#### 4.1.1 Draft changes to the STPIS

The AER is currently reviewing the STPIS and, in December 2017, published its draft position on an amended scheme. Ausgrid supports most aspects of the draft amended STPIS, as outlined in our submission to the AER.

An aspect of the draft amended STPIS which we would like to engage further with the AER is the proposed rebalancing of the current 50/50 allocation of incentives between SAIFI (frequency of outages) and SAIDI (duration of outages). This is to a 60/40 weighting in favour of SAIDI.

Ausgrid favours an approach to the allocation of incentives between SAIFI and SAIDI which encourages greater stakeholder consultation. This can be achieved if the amended STPIS does not bind the AER to a fixed SAIFI and SAIDI incentive ratio, but sets an allowable range from which the actual allocation can be set through the distribution determination process. Such an approach aligns with how other scheme parameters are set under the current STPIS and would encourage greater consultation and targeted research into customer reliability preferences when a regulatory proposal is submitted.

To facilitate this, Ausgrid plans to undertake further research into customer reliability preferences, and provide the results to the AER with our revised proposal. At this stage, however, the current research appears to indicate that customers have a preference for SAIFI over SAIDI improvements.<sup>20</sup> If further research shows this to be the case, then this

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<sup>19</sup> NER clause 6.6.2(a).

<sup>20</sup> Oakley Greenwood, New value of customer reliability, 30 May 2012, p. 7.

preference should be reflected in the allocation of incentives applied to Ausgrid under the STPIS.

#### 4.1.2 Application to the 2019-24 regulatory period

We support the AER's position to continue to apply the national STPIS to Ausgrid in the 2019-24 regulatory control period. By providing incentives to maintain and improve existing levels of reliability and customer service performance, the STPIS plays an important role in promoting efficient price and non-price outcomes, in the long term interests of consumers.

Ausgrid is also generally supportive of the AER's proposed arrangements, with some minor exceptions. The remainder of this section explains how we consider the STPIS should apply to Ausgrid.

In summary, the key elements of our proposal are as follows:

- A total proportion of revenue at risk of  $\pm 5\%$ . This represents an increase from the current regulatory period, where  $\pm 2.5\%$  was placed at risk. In its 2015-19 determination the AER reasoned that a more conservative level of revenue at risk was appropriate given that it was a new scheme. However, any transitional issues have now been resolved. Our stakeholders also support the continued application of an incentive to maintain and improve service performance, noting the symmetrical nature of the scheme.
- In terms of reliability parameters, we propose a revenue at risk of  $\pm 4.5\%$ . Our proposal is to apply the SAIDI and SAIFI parameters, which relate to duration and frequency of outages.<sup>21</sup> We propose that the exclusion events identified in the AER's guidelines apply to Ausgrid when calculating reliability performance.
- For customer service parameters, we propose a revenue at risk of  $\pm 0.5\%$ . Ausgrid proposes that when an event is excluded from the calculation of reliability performance, the event should also be excluded from the calculation of our telephone service performance.
- Ausgrid agrees with the AER that the reliability performance targets should be based on average performance over the last five years, as opposed to the current approach that uses trend analysis. However, we propose an amended approach to the customer service target. This is explained further below.
- We support the application of the Value of Customer Reliability (VCR) values set out in the Australian Energy Market Operator's (AEMO) 2014 report.

## 4.2 Rule requirements

The Rules set out a clear process on how the AER is to make a constituent decision on how an applicable STPIS is to apply to a DNSP for a regulatory control period. This section summarises the process prescribed under the NER, including a reference to relevant documents that the AER has already published prior to Ausgrid submitting our regulatory proposal:

- Under 6.6.2 of the NER, the AER must publish a STPIS for DNSPs to maintain and improve performance. The most recent amended version of the STPIS to apply to DNSPs is that published by the AER on 24 November 2009 (version 1.2).

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<sup>21</sup> We do not propose that Momentary Average Interruption Frequency Index (MAIFI) applies, because we are not able to accurately measure it at this time.

- The NER require that the AER set out its proposed approach to applying the current version of the STPIS in the Framework and Approach paper process.<sup>22</sup> The Framework and Approach paper published in July 2017 included a description of how the AER proposes to apply the STPIS to the 2019-24 regulatory period.
- The NER require that a DNSP's regulatory proposal provide a description, including relevant explanatory material, of how the DNSP proposes any STPIS that has been specified in a framework and approach paper that applies in respect of the forthcoming distribution determination should apply to it.<sup>23</sup>
- Clause 6.12.1(9) of the NER states that the AER must make a decision on how any applicable STPIS is to apply to the DNSP.
- Clause 6.3.2(a)(3) of the NER requires a building block determination to specify how any applicable STPIS is to apply.
- The building blocks used to calculate the annual revenue requirement for each regulatory year of a regulatory control period must include, amongst other things, any revenue increments or decrements for that year arising from the application of any STPIS.<sup>24</sup>
- The Regulatory Information Notice requires us to provide a detailed methodology for calculating the key parameters used in the STPIS, justification for any proposed adjustments to the STPIS targets away from those based upon raw historical data and data required in regulatory templates Workbook 1 – regulatory determination, 6.1 and 6.2.<sup>25</sup> The RIN also requires us to explain any variation or departure from the application of any component of the STPIS as set out in the F&A paper.<sup>26</sup>

### 4.3 Revenue at risk

The total revenue at risk is the maximum proportion of Ausgrid's annual revenue requirement that is subject to the STPIS. It places a limit on the quantum of the financial incentive.

For the current regulatory period the AER decided to apply a maximum revenue at risk of  $\pm 2.5\%$ . The AER considered this lower powered incentive would balance the risk to both consumers and Ausgrid and thus better meet the objectives of the STPIS.<sup>27</sup>

Ausgrid considers that it is appropriate to increase the amount of revenue at risk to  $\pm 5\%$  for the 2019-24 regulatory period. This is consistent with the AER's final F&A paper,<sup>28</sup> and with the application of the STPIS in the most recent revenue determinations for Victoria and South Australia.

In deciding to set Ausgrid's revenue at risk at  $\pm 2.5\%$  in the current regulatory period, the AER noted that a conservative level of revenue at risk was appropriate 'given the implementation issues with transitioning to a new scheme'.<sup>29</sup> We consider these implementation issues have been resolved and, as such, support a level of revenue at risk

<sup>22</sup> NER clause 6.8.1(b)(2)(iii).

<sup>23</sup> NER clause S6.1.3(4).

<sup>24</sup> NER clause 6.4.3(a)(5).

<sup>25</sup> RIN clause 19.

<sup>26</sup> RIN clause 1.7.

<sup>27</sup> AER, Ausgrid Final Decision 2015-19, Attachment 11 – Service target performance incentive scheme, April 2015, p.12.

<sup>28</sup> AER, Framework and Approach: Ausgrid, Endeavour Energy and Essential Energy, Regulatory Control Period commencing 1 July 2019, July 2017, p60.

<sup>29</sup> AER, Draft decision: Ausgrid distribution determination 2015-16 to 2018-19, Attachment 11: Service target performance incentive scheme, November 2014, p. 11-13.

for the 2019-24 regulatory control period at the standard level under the scheme; that is,  $\pm 5\%$ .

Noting the symmetrical nature of the incentives under the STPIS, our engagement with stakeholders has revealed support for placing  $\pm 5\%$  of revenue at risk under the scheme.

## 4.4 Reliability targets

Currently, two reliability targets apply to Ausgrid under the STPIS:

- Unplanned system average interruption duration index (SAIDI) – measures how long customers are without power for. It is calculated as the sum of the duration of each unplanned sustained customer interruption (in minutes) divided by the total number of distribution customers.
- Unplanned system average interruption frequency index (SAIFI) – measures how often customers are without power. It is calculated as the total number of unplanned sustained customer interruptions divided by the total number of distribution customers.

When applying unplanned SAIDI and unplanned SAIFI, the electricity distribution network is divided into segments by network type. Ausgrid's network is currently segmented into CBD, urban, short rural and long rural.

### 4.4.1 Revenue at risk

We consider that the revenue at risk allocated to reliability parameters should be  $\pm 4.5\%$ . This proportional division between reliability and customer service parameters is consistent with the proportion that currently applies.

### 4.4.2 Network segmentation

The scheme requires that to calculate revenue incentives, the electricity distribution network should be divided into segments by network type. When applying unplanned SAIDI and unplanned SAIFI we propose that the network area be divided into the following feeder types as defined in the NSW jurisdictional Licence Conditions and the AER's Draft Distribution Reliability Measures Guidelines:<sup>30</sup>

- CBD
- Urban
- Short rural
- Long rural.

These are consistent with the AER's final F&A and with the network segments applied in the current regulatory period.

### 4.4.3 Proposed reliability performance targets

Our method for establishing targets has drawn on past performance as a basis for developing forecasts, and has adopted average performance over the last 5 years.

Ausgrid calculated unplanned SAIDI and unplanned SAIFI targets in accordance with clause 3.2.1 of the STPIS for each network type. In the sections below, we set out how Ausgrid derives reliability data from its systems, and then proceed to set out how we derived our forecasted performance for the 2019-24 period.

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<sup>30</sup> Reliability and performance licence conditions for the operator of a transacted distribution system (dated 28 November 2016); AER, Draft Distribution Reliability Measures Guideline, June 2017.

#### 4.4.4 Reliability data

When reporting actual information, Ausgrid has relied on its systems that record reliability incidents. We derive daily unplanned SAIDI and unplanned SAIFI from individual interruption data.<sup>31</sup> The following assumptions have been made when calculating daily performance data:

1. All SAIDI and SAIFI metrics are calculated using daily customer counts. Ausgrid has consistently adopted this approach because average customer counts do not result in stable metrics suitable for trend analysis due to the constant adding, removing and reconfiguring of feeders.
2. All unmetered supplies are excluded from the calculation of SAIDI and SAIFI metrics.
3. All active customers are included in the calculation of SAIDI and SAIFI metrics. All inactive customers are excluded in the calculation of SAIDI and SAIFI metrics. The following assumptions regarding the definition of active and inactive customers have been made:
  - Active = Energised + De-energised
  - Inactive = Extinct + Deactivated
  - De-energised (AER) = Temporary disconnection (AUSGRID)
  - Inactive (AER) = Permanent disconnection (AUSGRID)
4. The following Major Event Day Thresholds ( $T_{MED}$ ) are applied to each year of historical data. These values are calculated in accordance with Appendix D of the STPIS:

**Table 2.**  *$T_{MED}$  applied to each year of historical data*

Year	$T_{MED}$
2013/14	2.60
2014/15	2.46
2015/16	2.84
2016/17	2.88
2017/18	2.97

5. All outage event attributes are accurately recorded in Ausgrid's Outage Management System (OMS).
6. Any interruption that spans multiple days is accrued to the day on which the interruption begins.
7. The following interruptions are excluded from daily performance data:
  - Momentary interruptions of one minute or less in duration<sup>32</sup>
  - Planned interruptions for which advance notice has been provided to the affected customers
  - Exclusions as per Clause 3.3 and Appendix D of the STPIS.

<sup>31</sup> The individual interruption data to be used in calculating STPIS parameters is contained in Ausgrid's annual RIN template 6.2.

<sup>32</sup> AER, *Draft DNSP Service Target Performance Incentive Scheme (version 2)*, December 2017, p. 25.



#### 4.4.5 Forecast targets

For the purposes of the 2019-24 regulatory period, targets for unplanned SAIDI and unplanned SAIFI for each network type are set on the basis of our historic performance over the past five regulatory years. The raw historical data used to calculate the targets is set out in Ausgrid's completed regulatory RIN template 6.2. The raw data has had exclusions under clause 3.3 and Appendix D of the STPIS applied.

Ausgrid's proposed performance targets for the 2019-24 regulatory control period are set out in the table below.

**Table 3. Proposed SAIDI and SAIFI for the 2019-24 regulatory period**

	2019/20	2020/21	2021/22	2022/23	2023/24
<b>Unplanned SAIDI</b>					
CBD	15.960	15.960	15.960	15.960	15.960
Urban	63.577	63.577	63.577	63.577	63.577
Short rural	141.202	141.202	141.202	141.202	141.202
Long rural	550.237	550.237	550.237	550.237	550.237
<b>Unplanned SAIFI</b>					
CBD	0.054	0.054	0.054	0.054	0.054
Urban	0.647	0.647	0.647	0.647	0.647
Short rural	1.317	1.317	1.317	1.317	1.317
Long rural	2.977	2.977	2.977	2.977	2.977

#### 4.4.6 Exclusions and our proposed Major Event Day Threshold

The scheme requires that certain defined events may be excluded when calculating the revenue increment or decrement under the scheme when an interruption on the DNSP's distribution network has not already occurred or is occurring at the same time.

These include load shedding due to: a generation shortfall; automatic load shedding due to the operation of under frequency relays following the occurrence of a power system under-frequency condition; load shedding at the direction of the AEMO or a system operator; load interruptions caused by a failure of the shared transmission network; load interruptions caused by a failure of transmission connection assets except where the interruptions were due to inadequate planning of transmission connections and the DNSP is responsible for transmission connection planning; and load interruptions caused by the exercise of any obligation, right or discretion imposed upon or provided for under jurisdictional electricity legislation or national electricity legislation applying to a DNSP.

An event may also be excluded where daily unplanned SAIDI for the DNSP's distribution network exceeds the major event day (MED) boundary defined in the scheme. Ausgrid proposes to derive MED thresholds at the end of each regulatory year for use during the next regulatory year using the 2.5 beta method in accordance with Appendix D of the STPIS. Ausgrid found the lognormal distribution to be acceptable and therefore Ausgrid will continue to follow step 4 (b) of Appendix D of the STPIS when calculating MED thresholds.

#### 4.4.7 Incentive rates

The incentive rates for unplanned SAIDI and unplanned SAIFI are calculated in accordance with clause 3.2.2 of the STPIS for each network type. Ausgrid uses the formulae provided in Appendix B of the STPIS. The sources for input parameters required in the formulae are set out in the table below.

**Table 4. Explanation of parameters**

Parameter	Source/calculation method
VCR	As described in section 4.4.6 below
CPI	CPI as applied to regulatory price setting
$W_n$	Weighting for unplanned SAIDI and unplanned SAIFI in Table 1 of the STPIS
$C_n$	<p>The expected average annual energy consumption by network type for the 2019-24 regulatory control period. This is calculated according to the following method:<sup>33</sup></p> <ol style="list-style-type: none"> <li>1. Calculate the 2016-17 annual energy consumption for each network type (by summing the energy consumption of active customers connected to each network type)</li> <li>2. Determine the ratio of energy consumption of each network type to total energy consumption.</li> <li>3. Multiply the forecast total energy delivered in 2019-20 (from Ausgrid's completed regulatory template 3.4) by the ratio from step 2 for each network type.</li> <li>4. Repeat steps 3 for regulatory years 2020-21 to 2023-24</li> <li>5. Calculate the expected average annual energy consumption for the 2019-20 to 2023-24 regulatory period for each network type.</li> </ol>
R	The average of Ausgrid's smoothed distribution revenue in nominal dollars. This is sourced from attachments 4.03 and 4.07.
$SAIDI_n$	The average of Ausgrid's proposed unplanned SAIDI targets for the 2019-24 regulatory control period.
$SAIFI_n$	The average of Ausgrid's proposed unplanned SAIFI targets for the 2015-19 regulatory control period.

Ausgrid's proposed incentive rates are set out in the table below, noting that incentive rates will require recalculation once the revenue requirements have been determined by the AER.

**Table 5. Incentive rates**

Incentive rate	
Unplanned SAIDI	
CBD	0.0054
Urban	0.0417
Short rural	0.0051
Long rural	0.0001
Unplanned SAIFI	
CBD	1.4101
Urban	4.2285
Short rural	0.5979
Long rural	0.0131

#### 4.4.8 Value of customer reliability

Following feedback from our stakeholders, we have adopted the Value of Customer Reliability (VCR) values set out in AEMO's 2014 report. We have indexed these values to July 2019, consistent with the approach set out in the STPIS. We have also amended the VCR for NSW CBD feeder type, so that it is based on energy consumption by user types as set out in AEMO's VCR application guide. This is consistent with the approach used by the AER in Ausgrid's previous regulatory determination, and reflects feedback from our stakeholders, who indicated a preference for using the values set by the AEMO report.

<sup>33</sup> Ausgrid does not forecast energy consumption by network type.



## 4.5 Customer service targets

Currently there is one customer service target that applies to Ausgrid under the STPIS. This is the telephone answering parameter, which measures the proportion of calls forwarded to an operator that are answered in 30 seconds.

### 4.5.1 Revenue at risk

We consider that the revenue at risk allocated to reliability parameters should be  $\pm 0.5\%$ . This is the maximum revenue at risk permitted for an individual customer parameter under the STPIS, and represents a doubling of the proportion of revenue at risk from the current period. We are permitted to propose a different revenue at risk where this would satisfy the objectives of the STPIS, set out in clause 1.5.

We do not consider that a lower proportion of revenue at risk would better satisfy the objectives of the STPIS.

### 4.5.2 Proposed customer service performance targets

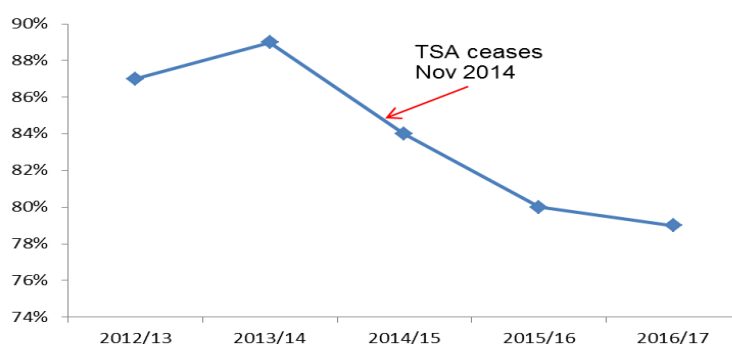
Our method for establishing the target for the telephone answering parameter has drawn on past performance as a basis for developing forecasts, but has not strictly adopted average performance over the last five regulatory years as a basis for establishing the targets, as required under clause 5.3.1(a) of the STPIS.

Instead, we have calculated our target based on our actual performance over the last three regulatory years. This will be updated to the last four regulatory years in our revised regulatory proposal, following the end of the 2017/18 regulatory year.

There are two main reasons for this. First, Ausgrid continued to share a call centre with our previous retail business until November 2014. Prior to this date, Ausgrid's call centre performance was aided by our ability to transfer calls to the retail line of our business under our Transitional Services Agreement (TSA) when a large volume of calls occurred. In our last regulatory proposal we noted that the restructure of our resources was yet to occur, but there was likely to be a reduction in resources which was expected to drive a reduction in telephone answering performance.<sup>34</sup> The AER accepted this, and approved a target of 75%.

In practice, while we were able to outperform our target, our performance did fall following the expiry of the TSA, as anticipated. This is shown in Figure 1. Financial years 2015/16 and 2016/17 are therefore the only years for which we have a true picture of Ausgrid's actual performance without the aid of the retail call centre.

**Figure 1. Percentage of calls answered within thirty seconds (ex MED)**



Source: Ausgrid Annual RIN data.

<sup>34</sup> Ausgrid, Attachment 3.02: Proposed application of STPIS for the 2014-19 period, May 2014, p.8.

Second, while providing a telephone answering service is still essential for many customers, increasingly customers expect to be able to find the information they need online. In recognition of this, we have upgraded our website to make it easier for customers to be able to find the information they need. This includes real-time access to outage information, and the ability for customers to be able to report outages online. Consistent with this, we have experienced a reduction in call volumes over the last two years. We expect this trend to continue.

Further, our stakeholders are concerned that the number of telephone calls answered within 30 seconds is not a meaningful customer service metric. As discussed in the next section, we are working with our stakeholders to develop a new, more meaningful target.

For these reasons, we do not consider it appropriate for Ausgrid to be incentivised to invest in additional resources, at additional costs to our customers, to support a service that is declining in use. A shift in customer expectations to be able to find and report information online, combined with recognition that the current customer performance target is not meaningful, suggests that we could be adding greater value to our customers in other areas of our service performance. While we do not currently have an appropriate replacement parameter, we do not consider that it is in our customers' long term interests to continue to invest in the existing measure.

For these reasons, and based on our historical performance with the majority of weight on the last two financial years, we consider that our revised telephone answering target should be 80% of calls answered within 30 seconds (excluding MED).

The raw historical data on a past performance is set out in Ausgrid's completed regulatory RIN templates 6.1 and 6.2. The raw data has had exclusions under clause 5.4 of the STPIS applied.

**Table 6. Proposed customer parameter targets for the 2019-24 regulatory period**

Customer service parameter	2019/20	2020/21	2021/22	2022/23	2023/24
Number of calls received	154,589	145,314	136,595	128,399	120695
Number of calls answered within 30 seconds	123,887	116,251	109279	102719	96556
Percentage of calls answered within 30 seconds	80%	80%	80%	80%	80%

#### 4.5.3 Telephone answering data

Telephone answering data for reporting purposes is captured from the Ausgrid Contact Centre in a number of Genesys tables from 6:30am to 10:00pm and in an Alcatel Application (CCSupervision) from 10:00pm to 6:30am.

Interactive Insights is the reporting application that combines both the Genesys and Alcatel data and provides a combined result across all queues and call types. Once run in Interactive Insights, filters are applied to the report to exclude any calls not relating to Emergency and Hazards, including Network Enquiries and Business to Business and internal Property calls.

#### 4.5.4 Exclusions

Ausgrid proposes that where a reliability exclusion occurs, this should also be excluded from the calculation of telephone answering performance. This is consistent with the scheme which states that where the impact of an event is to be excluded from the calculation of a revenue increment or decrement under the 'reliability of supply' component as provided for in clause 3.3, the impact of that event may be excluded from the calculation of a revenue increment or decrement for the 'telephone answering' parameter as appropriate.

#### **4.5.5 Incentive rates**

We propose to use the AER's incentive rate for the 'telephone answering' parameter of - 0.040% per unit of the 'telephone answering' parameter. This is consistent with clause 5.3.2 of the scheme.

#### **4.5.6 Development of a new customer service metric**

We consider improvements can be made to the current STPIS. In the course of our engagement, stakeholders have indicated that the telephone response time metric is not a meaningful indicator of customer service. Based on this feedback, we are in the process of working with stakeholders in exploring better measures of customer service. An option which stakeholders have found appealing is running a pilot scheme in parallel with the STPIS, which requires us to report on a new performance metric. This pilot scheme would not have any revenue at risk placed under it. However, the data we report in relation to it could be used to introduce targets for a new customer and stakeholder engagement performance metric in later regulatory control periods.

The proposed form of the new customer service performance metric is discussed in Chapter 9 of our Regulatory Proposal.

## 5 DEMAND MANAGEMENT INCENTIVE SCHEME AND INNOVATION ALLOWANCE

We propose the DMIS and DMIA apply to Ausgrid for the 2019-24 regulatory control period.

### 5.1 Overview

The NER require the AER to develop a Demand Management Incentive Scheme (DMIS) and a demand management innovation allowance mechanism (DMIA).<sup>35</sup> The DMIS is intended to provide DNSPs with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. The DMIA is intended to provide distributors with funding for research and development in demand management projects that have the potential to reduce long term network costs. Together, the DMIS and DMIA should provide benefits to customers by reducing network costs over time, lowering prices in future regulatory periods.

The rules requiring the AER to develop the DMIS and DMIA only took effect in 2016. However, an earlier version of the DMIS applied to Ausgrid's current regulatory period. Under this earlier scheme, Ausgrid was awarded an innovation allowance of \$1m per annum, with any underspend returned to customers.

### 5.2 Rule requirements

The NER set out a clear process on how the AER is to make a constituent decision on how an applicable DMIS/DMIA is to apply to a DNSP for a regulatory control period. In the sections below, we summarise the process prescribed under the Rules, including a reference to relevant documents that the AER has already published prior to Ausgrid submitting our regulatory proposal:

- Under 6.6.3 of the Rules, the AER must develop a DMIS. The objective of the DMIS is to provide DNSPs with an incentive to undertake efficiency expenditure on relevant non-network options relating to demand management. Version 1 of the DMIS was published in December 2017.<sup>36</sup>
- Under clause 6.6.3A of the Rules, the AER must develop a DMIA mechanism. The objective of the DMIA mechanism is to provide DNSPs with funding for research and development in demand management projects that have the potential to reduce long term network costs. Version 1 of the DMIA was published in December 2017.
- The Rules require that the AER set out its proposed approach to applying the DMIS and DMIA in the Framework and Approach paper process.<sup>37</sup> The Framework and Approach paper was published in July 2017, prior to the DMIS and DMIA being finalised.
- The Rules require that a DNSP's regulatory proposal provide a description, including relevant explanatory material, of how the DNSP proposes any DMIS or DMIA that has been specified in a framework and approach paper that applies in respect of the forthcoming distribution determination should apply to it.<sup>38</sup>
- Clause 6.12.1(9) of the Rules states that the AER must make a decision on how any applicable DMIS or DMIA is to apply to the DNSP.

<sup>35</sup> NER clauses 6.6.3 and 6.6.3A.

<sup>36</sup> AER, *Demand Management Incentive Scheme, Electricity distribution network service providers*, December 2017.

<sup>37</sup> NER clause 6.8.1(b)(2)(vi).

<sup>38</sup> NER clause S6.1.3(5).

- Clause 6.3.2(a)(3) of the NER requires a building block determination to specify how any applicable DMIS and DMIA is to apply.
- The building blocks used to calculate the annual revenue requirement for each regulatory year of a regulatory control period must include, amongst other things, any revenue increments or decrements for that year arising from the application of any DMIS or DMIA.<sup>39</sup>
- The Regulatory Information Notice requires us to explain any variation or departure from the application of any component of the DMIS as set out in the F&A paper.<sup>40</sup>

## 5.3 Application to the 2019-24 regulatory period

At the time of publishing its F&A paper, the AER was still finalising the design of its new DMIS/DMIA scheme. Despite this, the AER indicated its intention to apply the DMIS and DMIA.<sup>41</sup>

We support the AER's position to apply the new DMIS to Ausgrid. By providing incentives to undertake efficient expenditure on relevant non-network solutions the need for network investment may be deferred or removed. This plays an important role in promoting efficient price and non-price outcomes in the long term interests of consumers.

We also support the AER's position to continue to provide Ausgrid with an innovation allowance. As discussed further in Chapter 9 of our Regulatory Proposal, Ausgrid has effectively utilised the innovation allowance in the current regulatory period to deliver a number of innovative trials and projects that have the potential to be applied more broadly. These projects have the potential to reduce our costs and so the prices that customers face over the longer term.

### 5.3.1 Application of the DMIS

Ausgrid proposes that the DMIS should be applied in accordance with the AER's Demand Management Incentive Scheme published in December 2017. That is, a cost multiplier of 50% should be applied to any eligible project that becomes a committed project.

The DMIS provides real incentives to invest in demand management solutions where these are the least cost option. Ausgrid already conducts an economic assessment of demand management options. Our 2017 assessment reviewed \$540 million in network investment against non-network alternatives, comparing their respective costs and benefits. Where the net present value of benefits from the non-network solution is equal to or greater than the network option,<sup>42</sup> we choose the non-network solution.

For projects where the network option has an expected capital cost of more than \$5 million, we follow the Regulatory Investment Test for Distributors process to further assess demand management solutions, including seeking submissions from non-network solution providers. For smaller projects, in compliance with the AER's minimum project evaluation requirements, we will consult with market providers on potential non-network solutions.

This approach ensures that only efficient options would proceed under the DMIS. In doing so, Ausgrid also assesses the net benefit from the project, including the financial incentives provided under the DMIS, to ensure that applying this scheme will deliver net cost savings to retail customers. This is consistent with the NEO and the DMIS's objective in terms of

<sup>39</sup> NER clause 6.4.3(a)(5).

<sup>40</sup> RIN clause 1.7.

<sup>41</sup> AER, *Framework and Approach: Ausgrid, Endeavour Energy and Essential Energy, Regulatory Control Period commencing 1 July 2019*, July 2017, p.72-73 and 76.

<sup>42</sup> In practice, even non-network solutions typically involve some level of network investment combined with an efficient level of non-network solutions.

reducing the costs of operating our network, leading to lower prices for customers in the long term. This is also consistent with our objective of making our prices more affordable, and sustainable where we are able to employ low carbon alternatives to network investment.

### 5.3.2 Application of the DMIA

Ausgrid proposes that the DMIA should be applied in accordance with the AER's Demand Management Innovation Allowance Mechanism, published in December 2017.<sup>43</sup> That is, the DMIA for each year of the regulatory period should be calculated as the sum of:

- \$200,000 (in 2017 dollars, escalated by CPI to account for inflation)
- 0.075% of our AAR, as determined as part of this distribution determination.

We propose that the maximum allowance be applied to Ausgrid. This implies the following:

**Table 7. Demand management innovation allowance (\$ million, real 2019)**

	2019/20	2020/21	2021/22	2022/23	2023/24
Nominal MAR	1,605.4	1,640.7	1,664.1	1,691.6	1,674.0
MAR x 0.075%	1.2	1.2	1.2	1.3	1.3
Base amount	0.2	0.2	0.2	0.2	0.2
Total	1.4	1.4	1.5	1.5	1.5

The DMIA will give us additional funding to trial innovative demand management projects with the potential to reduce long-term network costs, consistent with the demand management innovation allowance objective set out in the NER. The DMIA will only be used where we are not able to obtain funding for R&D through other means. We will also share our findings publicly, ensuring that both industry and customers can understand and benefit from project outcomes.

Applying the DMIA will contribute to the NEO by providing us with the ability to trial projects that will reduce the cost of operating our network over the long term. In turn, this will reduce prices for our customers.

We have a demonstrated history of utilising the DMIA. Chapter 9 of our Regulatory Proposal provides details of projects that we were able to undertake with the DMIA that have, or will, benefit our customers. In chapter 9 we also set out future innovation projects that will help improve the range and cost effectiveness of non-network options to network needs, which may be fully or partially implemented during the 2019-24 period.

<sup>43</sup> AER, *Demand Management Innovation Allowance Mechanism, Electricity distribution network service providers*, December 2017

## 6 SMALL SCALE INCENTIVE SCHEME

We do not propose the application of a small scale incentive scheme.

The NER permit the AER to develop a small-scale incentive scheme.<sup>44</sup> To date, the AER has not developed a small scale incentive scheme. For this reason we do not propose the application of any small-scale incentive scheme.

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<sup>44</sup> NER clause 6.6.4(a).