Submission to the AER on its Preliminary Determination

Incentive Schemes

Summary

This document sets out Ergon Energy's response to the Australian Energy Regulator (AER) on the application of incentive schemes.

Ergon Energy accepts the AER's Preliminary Determination in relation to:

- the calculation of carryover amounts relating to the operation of the Efficiency Benefit Sharing Scheme (EBSS) in the regulatory control period 2010-15. Ergon Energy has recalculated the carryover amounts to align with the AER's Preliminary Determination
- the application of the Capital Efficiency Sharing Scheme (CESS) in the regulatory control period 2015-20, noting our position that the CESS should only apply in conjunction with an EBSS
- the application of the Service Target Performance Incentive Scheme (STPIS), with the exception of the cap on the reliability of supply component. Ergon Energy has recalculated the incentive rates to align with the AER's Preliminary Determination on the new Value of Customer Reliability (VCR) and our revised smoothed annual revenue. Ergon Energy has retained our position on all other elements of the STPIS in the revised Regulatory Proposal
- the Demand Management Incentive Scheme (DMIS). The AER's Preliminary Determination is consistent with the approach proposed in our Regulatory Proposal.

However, we reject the AER's decision:

- not to apply an EBSS in the regulatory control period 2015-20. Ergon Energy has retained our position in the revised Regulatory Proposal
- to reject the proposed exclusions from the operation of the CESS. Ergon Energy has restated our position in the revised Regulatory Proposal
- to introduce a cap of ±1.8 per cent on the reliability of supply component of the STPIS as we believe it is inconsistent with the national STPIS. Ergon Energy has retained our position in the revised Regulatory Proposal.

Finally, Ergon Energy has updated the incentive rates for the STPIS to reflect our revised smoothed annual revenue.

Outcomes

In light of the above, Ergon Energy has recalculated:

- the incentive rates for the STPIS to align with the AER's Preliminary Determination on the new VCR and our revised smoothed annual revenue. This results in a lower incentive rate than our October Regulatory Proposal
- the carryover amounts relating to the operation of the EBSS in the regulatory control period 2010-15 to align with the AER's Preliminary Determination.

Contents

1. Introduction

On 30 April 2015, the Australian Energy Regulator (AER) released its Preliminary Determination on Ergon Energy's Regulatory Proposal for the regulatory control period commencing on 1 July 2015 and ending on 30 June 2020.

This document details our response to the AER's Preliminary Determination and stakeholder comments on the application of incentive schemes. We have made revisions to our Regulatory Proposal and its supporting documents to reflect these positions, where necessary. In addition, we have updated the incentive rates for the Service Target Performance Incentive Scheme (STPIS) to reflect our revised smoothed annual revenue.

Ergon Energy has structured this document in the following manner:

- Chapter 2 summarises the AER's Preliminary Determination in relation to the application of incentive schemes.
- Chapter 3 outlines issues raised by stakeholders since the lodgement of our October Regulatory Proposal, both through our own consultation process and the AER's consultation process.
- Chapter 4 provides our response to the positions adopted by the AER, as well as stakeholder concerns.
- Chapter 5 sets out areas of our October Regulatory Proposal which have been revised due to new or updated information, or changes in methodology.

2. AER's Preliminary Determination

Attachments 9 – 12 of the AER's Preliminary Determination detail its positions on the application of incentive schemes. The following sections summarise these positions and the AER's rationale.

2.1. Efficiency Benefit Sharing Scheme (EBSS)

2.1.1. Carryover amounts accrued during the regulatory control period 2010-15

The AER accepted our proposal to apply a carryover reward to our regulated revenue, but substituted its own value of $130.1 million. This is due to the removal of movements in provisions from the EBSS calculation. The AER did not consider that the increases in provisions reflect the actual cost incurred in delivering network services as they are a revised estimate based on assumptions. The carryover amounts determined by the AER in its Preliminary Determination are detailed in Table 1.

Table 1: AER preliminary determination on EBSS carryover amounts ($ million, 2014-15)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Carryover Amount	34.5	48.8	64.1	(17.3)	0.0	130.1

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 9 – Efficiency benefit sharing scheme*, April 2015, p6.

2.1.2. Application in regulatory control period 2015-20

The AER decided not to apply the EBSS in the regulatory control period 2015-20. The AER noted the linkage between the current version of the EBSS and the revealed costs approach to assessing operating expenditure. That is, if the incentive framework works effectively, the actual operating expenditure incurred in the base year should be representative of the efficient level; thus leading to the adoption of the base year revealed costs in the AER's operating expenditure forecasts.

While the revealed costs approach will continue to be used to assess forecasts, the AER will test efficiency and adjust the forecast if it is inefficient. This places less weight on the revealed costs approach.

In Ergon Energy's case, the AER has determined that our operating expenditure is higher than that of a benchmark efficient service provider. Consequently, there is uncertainty around whether the AER will use the revealed costs from the regulatory control period 2015-20 when forecasting operating expenditure in the following period. If they are not used, the AER considers the EBSS should not apply.

2.2. Capital Expenditure Sharing Scheme (CESS)

The AER decided to apply version 1 of the CESS to Ergon Energy in the regulatory control period 2015-20. The AER did not support Ergon Energy's proposal that we should be able to seek exclusions for:

- Customer Connection Initiated Capital Works (CCICW) expenditure being above or below the expected AER allowances or forecasts

- decisions by Ergon Energy to not apply for pass throughs for events that may meet the threshold but generate capital costs that could contribute to over-expenditure of allowances.

The AER did not consider there was sufficient evidence to allow exclusions for capital expenditure resulting from uncontrollable events. Specifically, the AER believed:

- there was no reason why underspends or overspends should be shared differently between Ergon Energy and customers in each regulatory year, or shared differently to other costs
- Ergon Energy would not always be penalised or rewarded under the CESS for underspends or overspends on CCICW, as the CESS rewards and penalties are determined relative to the total forecast capital expenditure (not the category)
- Ergon Energy should take into account the issues raised, in terms of pass throughs, when making expenditure decisions.

2.3. Service Target Performance Incentive Scheme (STPIS)

The AER decided to apply the STIPIS to Ergon Energy in the regulatory control period 2015-20 in the following way:

- set revenue at risk at ± 2 per cent
- segment Ergon Energy's network according to feeder categories urban, short rural and long rural
- set applicable reliability of supply (system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI)) and customer service (telephone answering) parameters
- set performance targets based on Ergon Energy's average performance over the past five regulatory years
- apply the methodology indicated in the national STPIS for excluding specific events from the calculation of annual performance targets
- apply the methodology and value of customer reliability (VCR) values to the calculation of incentive rates using the latest estimate of VCR for Queensland.

The AER generally accepted the positions put forward by Ergon Energy in relation to the STPIS. It did not accept our proposed performance targets or the VCR value (and hence, our proposed incentive rates).

2.3.1. Revenue at risk

The AER accepted our proposal to cap the revenue at risk at ± 2 per cent. Within this, the AER applied a cap of ± 1.8 per cent for the reliability of supply component and ± 0.2 per cent for the customer service component.

2.3.2. Incentive rates

The incentive rates parameters are calculated with reference to the VCR. The AER has applied the VCR value determined by the Australian Energy Market Operator (AEMO) in its recent review of the VCR,[1] rather than applying the VCR value prescribed in the national STPIS.

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[1] AEMO (2014), *Value of Customer Reliability Review, Final Report*, September 2014.

The incentive rates determined by the AER, using the AEMO VCR value and the smoothed annual revenue determined from its Preliminary Determination, are detailed in Table 2.

Table 2: AER incentive rates on reliability of supply targets

	Urban	Short rural	Long rural
SAIDI	0.01541	0.01538	0.00332
SAIFI	1.33964	1.75543	0.50072

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 11 – STPIS*, April 2015, p8.

The AER determined the incentive rate for the telephone answering parameter will be -0.04 per cent per unit of the telephone answering parameter.

2.3.3. Performance targets

The AER accepted our approach to set performance targets for SAIDI and SAIFI based on historical averages, as well as our revised performance targets.[2] These performance targets set out in Table 3 below.

Table 3: AER SAIDI and SAIFI performance targets, 2015-20

	Preliminary Determination
SAIDI	
Urban	126.73
Short rural	317.06
Long rural	742.47
SAIFI	
Urban	1.503
Short rural	3.019
Long rural	5.348

Source: AER (2015), *Preliminary Decision, Ergon Energy determination 2015-16 to 2019-20, Attachment 11 – STPIS*, April 2015, p8.

The AER has decided to apply our proposed performance target for the telephone answering parameter of 77.3 per cent of calls being answered in 30 seconds.

The AER determined it would not apply the STPIS Guaranteed Service Level (GSL) scheme, as Ergon Energy must comply with the existing jurisdictional GSL scheme.

2.4. Demand Management Incentive Scheme (DMIS)

The AER has determined to continue to apply Part A of the Demand Management Incentive Allowance (DMIA) in the regulatory control period 2015-20. The innovation allowance amount will be $1 million per annum (real $2014-15).

[2] The performance targets proposed in our initial Regulatory Proposal were based on average historical performance that had been adjusted to take into account the expected reliability outcomes of our automatic circuit reclosers and remote control switch capital expenditure programs. The STPIS guideline only requires an adjustment if the expenditure was part of the reliability improvement program. Consequently, in April 2015, we submitted revised performance targets that did not include this adjustment.

3. Stakeholder comments

Stakeholders have raised a number of concerns in relation to the application of incentive schemes since the lodgement of our initial Regulatory Proposal on 31 October 2014. The Consumer Challenge Panel (CCP) also highlighted issues relating to incentive mechanisms. This section outlines these concerns.

3.1. Efficiency Benefit Sharing Scheme

3.1.1. AER consultation

Carryover amounts accrued during the regulatory control period 2010-15

A number of stakeholders do not support the application of the carryover amounts accrued during the regulatory control period 2010-15. The Alliance of Electricity Consumers and COTA Queensland recommended the AER reject our proposed carryover revenue adjustment, on the basis that inefficient costs should be borne by the business and not be passed on to customers[3] and the previous operating expenditure allowances were already over-generous.[4] The carryover revenue adjustment was also not supported by Townsville Enterprise.[5]

Application in regulatory control period 2015-20

A number of stakeholders do not support the application of the EBSS in the regulatory control period 2015-20.[6] Overall, QCOSS does not consider there is adequate evidence that the identified incentive schemes drive more efficient behaviour. QCOSS considers that incentives, if they apply at all, should be very modest and should only be in areas where there is a clear and demonstrable link between reduced spending and efficiency.[7]

The EUAA also queried the effectiveness of the EBSS in terms of providing suitable incentives for network owners and whether benefits really flow through to consumers, therefore suggests the AER remove these schemes.[8]

The Chamber of Commerce and Industry Queensland recommended the AER should negotiate targets that deliver genuine efficiency improvements and incentivise best practice.[9]

3.1.2. Consumer Challenge Panel

The CCP recommend that the AER should not apply the EBSS to Ergon Energy, as it is not confident that the AER will be able to apply the scheme to deliver genuine efficiency improvements that are in consumers' long-term interests. The CCP agrees with the AER's conclusions that Distribution Network Service Providers (DNSP) will face strong incentives to make efficiency improvements while

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[3] Alliance of Electricity Consumers (2015), Submission on Ergon Energy's regulatory proposal 2015-20, p29.
[4] COTA Queensland (2015), Submission on Ergon Energy's regulatory proposal 2015-20, p2.
[5] Townsville Enterprise (2015), Submission to the QLD electricity distributors' regulatory proposals, 30 January 2015, p4.
[6] Alliance of Electricity Consumers (2015), Submission on Ergon Energy's regulatory proposal 2015-20, p29; Australians in Retirement – Cairns and Northern Districts Branch (2015), Submission on Qld distributors' regulatory proposals 2015-20, p2; and Energy Users Association of Australia (2015), Submission on Ergon Energy's regulatory proposal 2015-20, p30.
[7] QCOSS (2015), Submission on Qld distributors' regulatory proposals 2015-20, pp 91-92.
[8] Energy Users Association of Australia (2015), Submission on Ergon Energy's regulatory proposal 2015-20, p. 30.
[9] Chamber of Commerce and Industry Queensland (2015), Submission on Ergon Energy's regulatory proposal 2015-20, p22.

their actual operating expenditure (opex) is higher than that of a benchmark efficient service provider, and there is no need to apply an EBSS to further strengthen those incentives.[10]

3.2. Capital Expenditure Sharing Scheme

3.2.1. AER consultation

Similar to the EBSS, a number of stakeholders did not did not support the application of the CESS.[11] The Australians in Retirement organisation does not support incentives[12] and the Alliance of Energy Consumers believes the CESS protects networks' inefficient expenditure and does not provide the appropriate incentives for Ergon Energy to invest in and operate its network efficiently.[13]

QCOSS noted the complexity and potential for error under the CESS and suggested as small a CESS incentive as possible, or no incentive arrangement at all. If a CESS is introduced, QCOSS suggested it will be imperative to set the capital expenditure (capex) forecast for 2015-2020 against efficient and prudent expenditure consistent with best practice rather than improvement on existing practice. Setting targets consistent with the DNSP current inefficient capex practices would reward them for reducing their level of inefficiency.[14]

3.2.2. Consumer Challenge Panel

The CCP made no comments on the CESS in its submission.

3.3. Service Target Performance Incentive Scheme

3.3.1. AER consultation

Some stakeholders did not support the application of the STPIS.[15] For example, the Alliance of Electricity Consumers indicated that Ergon Energy is meeting our STPIS targets through our N-1 network planning obligations, rather than through innovative network management. They considered that providing rewards for meeting legislative levels of service is not in the interests of consumers.[16]

QCOSS also suggested there is little evidence that customers, in aggregate, want improved reliability. QCOSS recommended the STPIS targets should be maintained at the current level in 2015-16 and reduce gradually to reflect the declines in reliability forecast by the Department of Energy and Water Supply following a cut in reliability obligations.[17]

Another stakeholder also raised concerns that the application of the STPIS to the distribution network as a whole does not help customers experiencing localised reliability issues.[18] Rather, focus should be placed on feeders that are of strategic importance for industry development and employment, and encouraging generation.

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[10] Hugh Grant (CCP Member) (2015), Advice on Energex and Ergon regulatory proposals, p 26.
[11] Alliance of Electricity Consumers, (2015), Submission on Ergon Energy's regulatory proposal 2015-20, p29 and Australians in Retirement – Cairns and Northern Districts Branch(2015), Submission on Qld distributors' regulatory proposals 2015-20, p2.
[12] Australians in Retirement – Cairns and District Branch (2015), Submission on Qld distributors' regulatory proposals 2015-20, p2.
[13] Alliance of Electricity Consumers, (2015), Submission on Ergon Energy's regulatory proposal 2015-20, p29.
[14] QCOSS (2015), Submission on Qld distributors' regulatory proposals 2015-20, p. 94.
[15] Australians in Retirement – Cairns and District Branch (2015), Submission on Qld distributors' regulatory proposals 2015-20, p29; and QCOSS (2015), Submission on Qld distributors' regulatory proposals 2015-20, pp 95-96.
[16] Alliance of Electricity Consumers (2015), Submission on Ergon Energy's regulatory proposal 2015-20, p29.
[17] QCOSS (2015), Submission on Qld distributors' regulatory proposals 2015-20, pp 95-96.
[18] Cummings Economics (2015), Submission on Ergon Energy's regulatory proposal 2015-20, pp 25-26.

3.3.2. Consumer Challenge Panel

The CCP recommended that the AER determine targets that deliver genuine efficiency improvements, incentivise best practice and appropriately reflect the recent changes to the Queensland planning and reliability standards, together with Queensland's customers' willingness to pay.[19]

3.4. Demand Management Incentive Scheme

3.4.1. AER consultation

There was mixed support for demand management incentives. The following organisations support the use of incentives:

- the Far North Queensland Regional Organisation of Councils recommended having incentives to manage demand during peak times, to better manage capital expenditure and utilisation[20]
- SPA Consulting Engineers suggested the AER work with Ergon Energy to increase incentives for demand side control, specifically additional funding for initiatives to increase load factor.[21]

On the other hand, the Australians in Retirement organisation does not support incentives[22] and the Local Government Association of Queensland (LGAQ) believes the AER should carefully consider proposed demand management initiatives in light of existing off-grid solutions.[23] While supportive of demand management incentives, the Total Environment Centre was disappointed that information on our proposed DMIA activities was not available and was concerned that Ergon Energy would not spend the entire DMIA.[24]

3.4.2. Consumer Challenge Panel

The CCP suggested the AER should consider consumers' willingness to pay for any costs resulting from the DMIS, and ensure decisions regarding proposed demand management expenditure deliver clear tangible cost benefits to consumers.[25]

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[19] Hugh Grant (CCP Member) (2015), Advice on Energex and Ergon regulatory proposals, p 27.
[20] Far North Queensland Regional Organisation of Councils (2015), Submission on Qld distribution regulatory proposals 2015-20, p7.
[21] SPA Consulting Engineers (QLD) Pty Ltd (2015), Submission on Ergon Energy's regulatory proposals 2015-20, p3.
[22] Australians in Retirement – Cairns and District Branch (2015), Submission on Qld distributors' regulatory proposals 2015-20, p2.
[23] Local Government Association of Queensland (2015), *Submission in response to the AER's Issues Paper*, 30 January 2015, p1.
[24] Total Environment Centre (2015), Submission on Qld distributors' regulatory proposals 2015-20, p13.
[25] Consumer Challenge Panel (CCP2) (2015), Submission on Energex and Ergon 2015-20 Capex and Opex Proposals, p 28.

4. Our response

This section outlines our response to the AER's Preliminary Determination and stakeholder comments on the application of incentive schemes in the regulatory control period 2015-20.

4.1. Efficiency Benefit Sharing Scheme

4.1.1. Carryover amounts

Ergon Energy accepts the AER's adjustments to the calculation of the carryover amounts relating to the operation of the EBSS in the regulatory control period 2010-15. We have recalculated the carryover amounts contained in our October Regulatory Proposal to align with the AER's Preliminary Determination.

Table 4: Proposed EBSS carryover amounts ($ million, 2014-15)

	2015-16	2016-17	2017-18	2018-19	2019-20	Total
Carryover Amount	34.5	48.8	64.1	-17.3	0.0	130.1

Regarding feedback from stakeholders, Ergon Energy notes that our carryover amounts were calculated in accordance with the formulas set out in the AER's Electricity distribution network service providers EBSS. We note that stakeholder submissions regarding the calculation of carryover amounts are matters regarding the design of the incentive scheme rather than the application of the EBSS to Ergon Energy specifically.

4.1.2. Application in the regulatory control period 2015-20

Ergon Energy disagrees with the AER's decision not to apply the EBSS in the regulatory control period 2015-20.

The EBSS was created to enhance incentives for Ergon Energy to spend only efficient opex – we will be rewarded for making efficiency gains and penalised for making efficiency losses equally over the 2015-20regulatory control period 2015-20. It also ensures any efficiency gains will be shared with customers with a sharing ratio of 30:70, and helps smooth out the benefits and penalties, thereby negating incentives to shift expenditure to the back of the regulatory control period.

Ergon Energy believes it was the intention of the Better Regulation Program that the EBSS and CESS work together to provide balanced expenditure incentives, across opex and capex.

Not applying an EBSS, while applying a CESS, will affect the relative balance in incentives. In this situation, opex incentives will be greater than capex incentives, as a DNSP will retain all of any opex underspend during the regulatory control period. Ergon Energy notes that in its explanatory statement for the CESS, the AER identified reasons it considered imbalanced incentives to be a problem, in particular that imbalanced incentives could distort decisions on whether to undertake opex or capex and that it could also lead a network service provider to change its capitalisation policy to reclassify costs between capex and opex.[26]

[26] AER, Better Regulation – Capital Expenditure Sharing Scheme for Electricity Network Service Providers, Explanatory Statement, November 2013, p. 19.

> " ... As the incentives for efficient capex differ significantly from the incentives for efficient opex - particularly towards the end of a regulatory control period - this could distort decisions on whether to undertake opex or capex. It could also lead a NSP to change its capitalisation policy to reclassify costs between capex and opex. "
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> " ... NSPs already currently receive a reward/penalty of about 30 per cent of any efficiency gain/loss in opex. We have decided to also set the reward and penalty for capex at 30 per cent to achieve better balance between opex and capex. We expect this will further encourage NSPs to seek the most efficient solution when deciding whether to incur capex or opex."

Ergon Energy agrees with the AER that providing balanced capex and opex incentives ensures a DNSP has incentives to undertake efficient expenditure across both opex and capex.

We also note that not applying the EBSS will similarly affect the balance between opex incentives and the incentives to maintain and/improve service levels provided by the STPIS. This balance in incentives was recognised by the AER in developing the CESS:

> " ... The incentives for capex, opex and service are balanced so that any capex deferral either increases opex or reduces payments under the Service Target Performance Incentive Scheme (STPIS)."

None of the reasons for introducing the EBSS in the first place have ceased to apply to Ergon Energy. Each of them continue to have force, and should be given the same weight in Ergon Energy's case as they are for each other DNSP.

Further, the AER's position pre-empts a decision on the efficiency or otherwise of Ergon Energy's revealed costs in the regulatory control period 2015-20, and the forecasting methodology the AER may apply for the regulatory control period 2020-25. The AER says it has approved a forecast opex allowance for Ergon Energy which it believes satisfies the opex criteria – the same approach that it has taken for each other DNSP. If, in our next base year, Ergon Energy is able to spend less than the AER's forecast, we will have responded to the incentives created by this forecast. It is true that the 'efficiency frontier' may move in the meantime, but this is equally true for every other DNSP. There is no basis on which the AER can properly conclude that it is more or less likely to use revealed costs to set Ergon Energy's next opex forecast than it is for any other DNSP. There is, in short, no reason to apply the EBSS to other DNSPs, but disallow it for Ergon Energy.

While we agree with the AER that we may be penalised twice should we overspend our opex allowance in the regulatory control period 2015-20 and the AER does not subsequently apply a revealed cost forecasting approach, we note that the AER has discretion under the EBSS to exclude, ex post, opex categories from the EBSS that are not forecast using a single year revealed cost approach in the following period.[27] Ergon Energy considers the AER should utilise this discretion in the regulatory control period 2020-25 should it not apply a revealed cost forecasting approach to determine opex, rather than seek to pre-empt a decision on the efficiency or otherwise of our costs in the regulatory control period 2015-20.

For these reasons, Ergon Energy proposes that the AER apply an EBSS for the regulatory control period 2015-20 as outlined in the Framework and Approach Paper, subject to the proposed adjustments for uncontrollable costs outlined in section 4.2.

Ergon Energy notes that stakeholders are generally not in support of incentive mechanisms. In particular, stakeholders questioned the ability of the EBSS to deliver genuine efficiency improvements. We note these are matters regarding the design of the incentive scheme rather than the application of the EBSS to Ergon Energy specifically.

4.2. Capital Expenditure Sharing Scheme

Ergon Energy accepts the AER's Preliminary Determination to apply the CESS during the regulatory control period 2015-20, as long as the EBSS similarly applies. However, Ergon Energy does not agree with the AER's reasons for not allowing us to seek exclusions for expenditure associated with uncontrollable events. The AER did not consider there was sufficient evidence to allow exclusions for capital expenditure resulting from uncontrollable events. Specifically, the AER believed:

- there was no reason why underspends or overspends should be shared differently between Ergon Energy and customers in each regulatory year, or shared differently to other costs
- Ergon Energy would not always be penalised or rewarded under the CESS for underspends or overspends on CCICW, as the CESS rewards and penalties are determined relative to the total forecast capital expenditure (not the category)
- Ergon Energy should take into account the issues raised, in terms of pass throughs, when making expenditure decisions.

As stated in our document *03.01.03 – Ergon Energy Incentive Schemes*, in its explanatory statement the AER has framed the creation of the CESS around the following issue set of issues:

> " ...the benefits to a NSP of underspending a given amount of capex are progressively less in each year during a regulatory control period. For instance, if a NSP underspends in the first year of a five year regulatory control period, it will not lead to a lower RAB until four and a half years later when we roll forward the RAB. If, on the other hand, the NSP underspends in the middle of the final year of a five regulatory control period, it will lead to a lower RAB half a year later when we roll forward the RAB. As the benefits of underspending to a NSP are smaller as the regulatory control period progresses, we say a NSP's incentives for efficient capex decline over the regulatory control period.
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> There are three main reasons why declining incentives for efficient capex may be a problem:

[27] AER, Better Regulation – Efficiency Benefit Sharing Scheme for Electricity Network Service Providers, Explanatory Statement, November 2013, section 2.1

There is a lack of discipline on capex towards the end of the regulatory control period.

There is little reward for underspending towards the end of the regulatory control period. Conversely, there is little penalty for overspending towards the end of the regulatory control period. This may mean NSPs are not as disciplined with their capex towards the end of a regulatory control period.

It could distort decisions about whether to undertake capex or opex:

A NSP's incentives to pursue efficient opex are the same in each year. As the incentives for efficient capex differ significantly from the incentives for efficient opex - particularly towards the end of a regulatory control period - this could distort decisions on whether to undertake opex or capex. It could also lead a NSP to change its capitalisation policy to reclassify costs between capex and opex.

Capex might be less efficient if NSPs skew their capex towards the end of the regulatory control period:

Unnecessary peaks and troughs in a NSP's investment programs can result in higher costs than a more stable work program. For example, if a large number of projects are undertaken during the final years of the regulatory control period, NSPs may rely more on external contractors for projects that could have been undertaken more efficiently by in-house staff. NSPs may also enter into less cost-effective contracts with external contractors if they are contracting at shorter notice and for a smaller scope of work rather than if they were offering a steady stream of work.

To address the issues identified above, regulators can apply a capex incentive mechanism to complement the rewards or penalties the NSP already receives for beating its capex forecasts. After such a mechanism is applied, the reward a NSP receives for an underspend, or the penalty it would face for an overspend, would be the same in each year. The additional reward or penalty is generally added to or subtracted from regulated revenues as an additional building block in the next regulatory control period."

While Ergon Energy appreciates the above concerns have been raised by stakeholders and others in developing new rules to support the 'Better Regulation' agenda, not all forms of capital expenditure undertaken by DNSPs are subject to the distortions and forms of 'gaming' that may be implied by the AER's analysis above. Equally, there are certain types of expenditure for which outturn expenditure will be driven, to a very significant extent, by circumstances beyond the DNSP's control. Ergon Energy submitted in our October Regulatory Proposal that the AER's incentive schemes need to take such matters into account to ensure that the incentive scheme minimises the possibility of windfall gains or losses that are driven by factors unconnected to a DNSP's performance.

Ergon Energy maintains that uncontrollable costs should be excluded, because neither Ergon Energy nor customers should be penalised for expenditure that is outside of our control. There are certain types of expenditure categories for which circumstances beyond a DNSP’s control drive, to a significant extent, expenditure. Ergon Energy believes that incentives schemes should take this into account to ensure the scheme minimises the possibility of a windfall gain or loss driven by factors unconnected to a DNSP’s performance.

The EBSS and CESS were designed to reward businesses for becoming more efficient over time, and penalise them for becoming less efficient. Rewarding, or penalising, a DNSP for changes in actual costs relative to forecasts that are due to factors outside the DNSP’s control undermines what the incentive schemes are intended to do. Without including a mechanism within the EBSS and CESS for a DNSP to ask for uncontrollable costs to be excluded, customers would pay for carryover amounts that do not reflect changes in the underlying level of efficiency in providing standard control services during the regulatory control period 2015-20. Instead, a portion of the carryover may represent changes in factors unconnected to Ergon Energy’s performance, for example the number of customer initiated connections performed within a period. To reward or penalise Ergon Energy for these uncontrollable changes would be contrary to the objectives of the incentive mechanisms under the National Electricity Rules (NER).

For example, a service provider has little ability to influence, accelerate, defer, or delay the timing of CICW expenditure as it is driven and triggered at the customer’s discretion, and Ergon Energy is under a regulatory obligation to connect the relevant customer. Differences between forecasts and actual expenditure for CCICW are significantly driven by customer discretion, rather than any change in the underlying level of efficiency in providing standard control services.

In particular, a DNSP, in meeting the relevant capital expenditure objective for CCICW expenditure, has little ability to unduly influence, accelerate, defer or delay the timing of such customer driven requirements and the DNSP remains ultimately under a regulatory obligation to connect the relevant customer.

In its explanatory statement published in support of the CESS, the AER stated:

> “ We acknowledge that the CESS will reward or penalise NSPs for some uncontrollable events. However, on the whole, the risk of uncontrollable events presents both upside and downside risk to NSPs and this risk can already be managed somewhat through pass-through events and contingent projects. We do not think that there is a compelling argument as to why uncontrollable costs should be shared differently to all other costs facing NSPs.
>
> While we accept that some events may be uncontrollable, in most cases, a NSP also still has the ability to control the costs associated with such events. Allowing exclusions would increase the risk that we would dilute a NSP’s incentives to improve its efficiency.”

These observations fail to address the rationale behind the proposal to exclude or make appropriate allowances for significant fluctuations in CCICW capex for CESS purposes. Irrespective of the nature of the incentives provided to a DNSP, it is simply a fact that there is less that a DNSP can do to improve efficiency in relation to capex, such as CICW, where demand is externally driven and essentially, triggered at the customer's discretion. There do need to be incentives to meet demand more efficiently, but there is almost nothing the DNSP can do to control volume or defer expenditure. This is why uncontrollable costs are different.

To the extent that a DNSP does have an ability improve efficiency, the DNSP will continue to be rewarded or penalised by reference to the difference between the forecast CICW allowance and outturn expenditure in a given year. However, this effect should not be exacerbated by the additional reward or penalty associated with the CESS. In either scenario the DNSP will be excessively rewarded or penalised (with the corresponding impact on customers) for a level of performance that was driven, to a material extent, by factors other than the DNSP's efficiency.

We note that the rewards and penalties are determined relative to total forecast capital expenditure, rather than at the category level. However, Ergon Energy believes costs that are uncontrollable should be excluded, as these do not reflect any change in the underlying level of efficiency in providing standard control services. Neither ourselves nor our customers should be penalised or rewarded for changes in expenditure that is outside our control and unrelated to changes in our underlying efficiency.

Likewise, a DNSP acting in the long term interests of consumers to avoid unnecessary price increases may make decisions to absorb the capital costs of events that might otherwise qualify for a pass through during the period under review, only to find themselves penalised if economic conditions, network demand or customer requirements necessitate over-expenditure of the allowances later on in the same period.

When these were put to the AER in developing the CESS, the AER responded in the following terms:

> " A NSP would avoid an automatic CESS penalty for increased capex if we approved the capex as part of a pass-through event. If a NSP wishes to avoid a CESS penalty it should submit a pass-through application. If we approve an increase in regulated revenue after assessing the pass-through application, then it is a business decision for the NSP as to whether it increases its tariffs to recover the additional revenue."

It is not clear to us why the AER would insist that a DNSP incur the administrative costs of applying for a pass through (costs which are ultimately borne by consumers), as well as imposing on the regulator the costs of a public consultation process and administrative decision, when the DNSP does not in fact wish to pass the costs of the relevant event through to customers. A pass through event, if granted, does not simply affect CESS calculations, it affects the DNSP's return on capital and depreciation in the period in which the pass through occurs, and arms the DNSP with the ability to pass those costs through to customers, whether or not it had intended to do so when the pass through application was made. Ergon Energy does not consider this approach to necessarily be in the long term interests of consumers and submits that the AER should consider the impact of decisions not to apply for a pass through on a more flexible basis under the CESS and EBSS.

Ergon Energy does not consider a service provider should be excessively rewarded or penalised for a level of performance that was driven by factors other than the service provider's efficiency. For this reason, we retain our position in our revised Regulatory Proposal.

Ergon Energy notes that in its Preliminary Determination, the AER decided not to apply the EBSS in the regulatory control period 2015-20. Ergon Energy disagrees with this position as outlined above. However, if the AER decides not to apply the EBSS, Ergon Energy believes that the CESS should also not apply. This is consistent with the intent of the Better Regulation Program which was for the schemes to work together to provide balanced expenditure incentives, across both opex and capex and service standards.

Ergon Energy recognises that the CESS operates independently of the EBSS. However:

- the CESS is part of a broad incentive framework which provides interrelated incentives through a variety of mechanisms (including the EBSS, DMIS, STPIS and CESS) for a DNSP to make efficient investment decisions and to balance expenditure efficiencies with service quality outcomes
- the interrelationship between the incentive mechanisms means the EBSS and CESS complement each other to ensure balanced capex and opex incentives and efficient expenditure decisions, across the regulatory control period.

For these reasons, Ergon Energy proposes that should the AER decide not to apply the EBSS in the regulatory control period 2015-20, the CESS should not apply.

Ergon Energy notes a number of stakeholders did not did not support the application of the CESS, in particular, stakeholders considered the CESS did not provide appropriate incentives for Ergon Energy to invest in and operate its networks efficiently. We note this is a matter regarding the design of the incentive scheme rather than the application of the CESS to Ergon Energy specifically.

4.3. Service Target Performance Incentive Scheme

Ergon Energy accepts the following components of the AER's Preliminary Determination on the STPIS:

- for the reliability of supply components:
    - set performance targets for both SAIDI and SAIFI
    - calculate Major Event Day thresholds using the 2.5 beta method set out in Appendix D of the national STPIS
    - divide our network into urban, short rural and long rural feeder types
    - set performance targets based on historical averages
- for the customer service component, apply the telephone answering parameter with a performance target of 77.3 per cent of calls being answered in 30 seconds and an incentive rate of -0.04 per cent
- not apply the GSL component, given the operation of the jurisdictional GSL scheme
- set the overall revenue at risk at ± 2 per cent.

Ergon Energy has concerns with the use of AEMO's VCR figures and does not accept the introduction of a cap on the reliability of service component. Our responses to these issues are outlined in the sections below.

Regarding the feedback from stakeholders, Ergon Energy notes that we are no longer subject to deterministic N-1 security standards. Further, our STPIS performance targets for the regulatory control period 2015-20 will be set with reference to our historical performance, not legislated levels of service. We continue to be subject to Minimum Service Standards (MSS) set by the Queensland Government. However, the MSS operates outside of the STPIS and does not impact any reward (or penalty) that Ergon Energy incurs under the STPIS. Further, the STPIS is an outcome focused mechanism intended to balance incentives to reduce expenditure with the need to maintain service quality.

While the STPIS provides an incentive to improve our average level of reliability over time, this is tempered by the need to demonstrate that our reliability program is prudent, efficient and meets our customers' expectations. The customer engagement we undertook as part of the development of our forecast works program demonstrates that reliability of supply remain an important factor for our customers, but that they are not necessarily willing to pay for improvements in that reliability.

Ergon Energy does not believe it makes sense to reduce the performance targets for reliability of supply, as this will make it easier for Ergon Energy to outperform, thereby earning a reward which will increase the prices paid by our customers. This is inconsistent with our customers' expectations more generally. Setting the reliability of supply targets based on historical performance means that the targets will move over time to reflect those customer expectations.

Ergon Energy also notes the concerns of some stakeholders that the STPIS does not address reliability performance at the feeder level, and agrees with the AER that this is a matter regarding the design of the incentive scheme rather than the application of the STPIS to Ergon Energy specifically. However, we note that we have proposed to continue our Worst Performing Feeder Improvement Program in the regulatory control period 2015-20 to address localised performance issues. Further information on this program is provided in *07.00.05 – (Revised) Reliability & Quality of Supply Expenditure Forecast Summary.*

4.3.1. Revenue at risk

In the Preliminary Determination, the AER introduced a cap of ± 1.8 per cent on the reliability of supply component of the STPIS.[28] This is inconsistent with its position in the Framework and Approach Paper, where it stated that it intended to continue to apply the STPIS to Ergon Energy in the regulatory control period 2015-20, with a maximum reward or penalty of ± 2 per cent of our Annual Revenue Requirement (ARR).

The AER did not acknowledge that the introduction of the cap on the reliability of service component was a change from how the STPIS is applied in the regulatory control period 2010-15, nor did it provide a reason for introducing this cap. Ergon Energy does not agree with the proposed change and believes it is inconsistent with the national STPIS.

The methodology outlined in the national STPIS includes a cap for the S-factor adjustment for customer service parameters and a limit on the overall S-factor adjustment. Specifically, the formulas set out in Appendix C of the national STPIS explicitly incorporates a cap on the customer service component by including a term that limits the sum of the raw S-factors for the customer service component to be between the upper and lower bounds of the cap set for that component by the AER. No equivalent term is included for the sum of the S-factors relating to the reliability of supply parameters.

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[28] AER, *Preliminary Decision Ergon Energy Determination 2015-16 to 2019-20, Attachment 11 – Service Target Performance Incentive Scheme*, April 2015, p.11-7.

Neither the national STPIS or the Framework and Approach Paper apply a cap to the reliability of supply S-factor. This approach is supported in the mechanics of the AER's worked example that is provided as Appendix E and the Revenue at Risk calculation methodology that is presented as Appendix C of the National STPIS. Therefore, Ergon Energy considers that the application of a cap to the reliability of supply component is inconsistent with the national STPIS and retain our position in the revised Regulatory Proposal that the following limits continue to apply:

- a total revenue at risk of ± 2.0 per cent of our ARR
- a cap on the service component of ± 0.2 per cent of our ARR.

4.3.2. Incentive rates

Ergon Energy has concerns with the use of AEMO's VCR figures. However, in the absence of other recent alternatives, Ergon Energy has applied these targets in our revised Regulatory Proposal. We have recalculated the incentive rates contained in our October Regulatory Proposal in light of the new VCR and our revised smoothed annual revenue. Our supporting document *03.02.02 – (Revised) Proposed Application of STPIS for the 2015-16 to 2019-20 Regulatory Control Period* sets out Ergon Energy's proposed incentive rates for the regulatory control period 2015-20.

Table 5: Proposed incentive rates on reliability of supply targets

	Urban	Short rural	Long rural
SAIDI	0.01195	0.01192	0.00257
SAIFI	1.03868	1.36080	0.38818

4.3.3. Performance targets

The AER's Preliminary Determination in relation to the STPIS performance targets is consistent with the approach in our initial Regulatory Proposal and, as such, we accept the AER's decision on this matter. Ergon Energy has not made minor revisions to our proposed performance targets to ensure consistent with the rounding used by the AER.

Table 6: Proposed Performance Targets, 2015-20

	Proposed Targets
SAIDI	
Urban	126.73
Short rural	317.06
Long rural	742.47
SAIFI	
Urban	1.503
Short rural	3.019
Long rural	5.348
Customer Service	
Telephone Answering	77.3%

4.4. Demand Management Incentive Scheme

The AER's Preliminary Determination in relation to the DMIS is consistent with the approach in our October Regulatory Proposal and, as such, we accept the AER's decision on this matter. Ergon Energy has not made any revisions to our proposal.

Consistent with the Preliminary Determination, we have included the DMIA as an individual line item within the revenue adjustment section of the Post Tax Revenue Model.[29]

Table 7: Estimated revenue allowances associated with DMIS ($ million, nominal)

	2015-16	2016-17	2017-18	2018-19	2019-20
DMIS (Part A, DMIA) 2015-20	1.03	1.05	1.08	1.11	1.13

We note stakeholder concerns regarding demand management incentives. However, we consider the long-term benefits of the scheme outweigh the minimal price impacts. The DMIA program complements our non-network alternatives program, which is geared towards providing a more efficient solution to network augmentation. DMIA projects funded in the regulatory control period 2015-20 have provided valuable insights and knowledge, and created the opportunity to move innovation from concept to business as usual.[30]

An example of a DMIA project is the alternative off-peak hot water tariff trial which is testing an approach that achieves reductions in electricity demand during peak times for hot water systems in areas were normal off-peak tariffs are not practical. The project aims to gauge participant's response to having their hot water controlled as per normal off-peak tariffs (tariff 33 or tariff 31) in return for an incentive payment. If this proves to be a successful approach to reducing electricity demand during peak times, it could be developed into a 'product' that could be utilised in constrained areas, or more widely throughout Ergon Energy's distribution area.[31]

In relation to LGAQ's comments, Ergon Energy notes that all nominated DMIA projects are subject to screening and feasibility processes, consistent with the AER's DMIS, and a subsequent cost-benefit analysis is undertaken to identify the highest value projects, based on factors including their ability to shape energy load profiles and gain community and customer acceptance.

[29] AER, *Preliminary Decision Ergon Energy Determination 2015-16 to 2019-20, Attachment 1 – Annual Revenue Requirement*, April 2015.
[30] Further information on the outcomes of DMIA funded projects can be found at https://www.ergon.com.au/network/network-management/demand-management/demand-management-plans-and-reports.
[31] https://www.ergon.com.au/network/network-management/demand-management/alternative-off-peak-hot-water-tariff-trial

5. Other revisions

5.1. Service Target Performance Incentive Scheme

Ergon Energy has proposed a number of changes in our revised Regulatory Proposal that have impacted the smoothed annual revenue used by the AER to determine the incentive rates. We have updated the STPIS incentive rates to reflect these changes, and the new VCR.

Table 8: Proposed incentive rates on reliability of supply targets

	Urban	Short rural	Long rural
SAIDI	0.01195	0.01192	0.00257
SAIFI	1.03868	1.36080	0.38818

Supporting documents

The following documents support our response to the AER on Incentive Schemes:

Name	Ref
(Revised) Application of Incentive Schemes	03.01.03
(Revised) Proposed Application of STPIS for the 2015-16 to 2019-20 Regulatory Control Period	03.02.02

Definitions, acronyms, and abbreviations

AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARR	Annual Revenue Requirement
Capex	Capital expenditure
CESS	Capital Expenditure Sharing Scheme
CCP	Consumer Challenge Panel
CICW	Customer Initiated Capital Works
DMIA	Demand Management Incentive Allowance
DMIS	Demand Management Incentive Scheme
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
Ergon Energy	Ergon Energy Corporation Limited
GSL	Guaranteed Service Level
MSS	Minimum Service Standards
NER	National Electricity Rules
Opex	Operating expenditure
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
STPIS	Service Target Performance Inventive Scheme
VCR	Value of Customer Reliability