03.01.03

Application of Incentive Schemes

Contents

1. Introduction

The National Electricity Rules (NER) give rise to a variety of schemes that provide network businesses with incentives to be efficient in their spending, to maintain service standards, and to economically manage demand for regulated services. These incentive schemes form part of a network business' distribution determination and are designed to reward network operators for over-performance or penalise them for under-performance, as measured against predefined benchmarks of reliability and efficiency.

The Australian Energy Regulator (AER) has published a set of guidelines for the incentive schemes and has also set out in its Framework and Approach Paper[1] how it proposes to apply these schemes to Ergon Energy for the regulatory control period 2015-20. Ergon Energy is required under the NER to provide, as part of its Regulatory Proposal, a description of how it proposes to meet the AER's expectations as outlined in those documents. This document therefore provides a description of how Ergon Energy intends to apply the incentive schemes under the NER for the regulatory control period 2015-20.

[1] AER (2014), *Final Framework and Approach for Energex and Ergon Energy, Regulatory control period commencing 1 July 2015*, April 2014.

2. Incentive Schemes

The AER's Framework and Approach Paper proposed to apply the following incentive schemes[2] to Ergon Energy in the regulatory control period 2015-20, with the objective of providing financial incentives for Ergon Energy to make efficient investment decisions and to maintain the efficiency of our expenditure, performance and services over time:

- **Demand Management Incentive Scheme (DMIS)** – provides incentives to Ergon Energy to commission efficient non-network solutions, such as distributed generation, to meet network constraints
- **Efficiency Benefit Sharing Scheme (EBSS)** – rewards Ergon Energy for efficiency gains and penalises Ergon Energy for efficiency losses as benchmarked against our approved operating expenditure forecasts, with any gains and losses outstanding at the end of a regulatory control period carried over into the next period
- **Service Target Performance Incentive Scheme (STPIS)** – encourages Ergon Energy to maintain and improve service performance by delivering financial rewards for over-performance or by imposing financial penalties for under-performance against service standard targets in the areas of reliability and customer service
- **Capital Expenditure Sharing Scheme (CESS)** – rewards Ergon Energy for underspends and penalises Ergon Energy for overspends as benchmarked against the approved capital expenditure program for the regulatory control period 2015-20. The CESS also allows the AER to undertake an ex-post review of capital works where an electricity distribution business overspends relative to its capital allowance and adjust the Regulatory Asset Base (RAB) for capital overspends which are not deemed prudent or efficient.

In Ergon Energy's October Regulatory Proposal, we supported the AER's proposed approach to the application of each scheme. However, we suggested that in the application of the CESS, the AER should carefully consider the potential impacts on the operation of the CESS that may be generated by Customer Connection Initiated Capital Works (CCICW) expenditure being above or below the expected AER allowances or forecasts for the 2015-2020 period or by decisions by a Distribution Network Service Provider (DNSP) 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. This latter concern also applied to the operation of the EBSS.

In its Preliminary Determination, the AER departed from the Framework and Approach Paper by deciding not to apply an EBSS for the regulatory control period 2015-20. It also did not allow provision for the exclusion of the matters raised in our October Regulatory Proposal regarding the operation of the CESS.

The method and timing of the Annual Revenue Requirement (ARR) adjustments associated with these incentive schemes vary, as shown in Table 1. The proposed schemes can result in rewards or penalties within the current regulatory control period or adjustments within future periods. As such, this document does not identify revenue increments or decrements associated with the EBSS and CESS for the regulatory control period 2015-20, as the adjustments resulting from these schemes will be made in the regulatory control period 2020-25.

[2] While the AER may apply a Small Scale Incentive Scheme (SSIS) to an electricity distribution business as part of a distribution determination, the AER has advised in its Framework and Approach Paper that it does not intend to apply this scheme to Ergon Energy in the regulatory control period 2015-20.

Table 1: Adjustments associated with application of incentive schemes in 2015-20

Incentive scheme	Method and timing of adjustment
DMIS	Revenue increment in the ARR calculation for 2015-20.
EBSS	Revenue increment/decrement in the ARR calculation for 2020-25. There will be no revenue impact in 2015-20.
STPIS	Adjustment to the ARR during the annual Pricing Proposal process. There is a two year lag between the performance year and the pass through of the reward or penalty in prices.
CESS	Revenue increment/decrement in the ARR calculation for 2020-25. There will be no revenue impact in 2015-20.

The details of these adjustments are specific to each scheme and are detailed below.

2.1 DMIS

2.1.1 Overview

The DMIS provides incentives to Ergon Energy to implement efficient non-network alternatives for managing expected demand on the network and efficiently connecting embedded generators. In its Preliminary Determination, the AER proposed to continue to apply Part A of the DMIS (i.e. the Demand Management Innovation Allowance (DMIA)) in the regulatory control period 2015-20. The AER accepted Ergon Energy's proposal to allow a DMIA of $1 million per annum (real $2014-15), consistent with the scheme applied to Ergon Energy in the regulatory control period 2010-15 and the AER's Framework and Approach Paper.

The AER noted in its Preliminary Determination that it will consider the introduction of a new DMIS following the Australian Energy Market Commission's Power of Choice rule change process.[3]

2.1.2 Current period outcomes

Ergon Energy has an active program to pursue non-network alternatives to the construction of network assets to deliver energy to customers. In the regulatory control period 2010-15, the non-network program for Ergon Energy's regulated network amounted to $65 million. This non-network expenditure was incurred where Ergon Energy could demonstrate that it was more cost-effective than traditional network solutions. As a consequence of this large program, Ergon Energy has not yet fully spent our allowance under the DMIA for the regulatory control period 2010-15.

Ergon Energy's DMIA expenditure for the regulatory control period 2010-15 is listed in Table 2 below and reflects 2010-14 actuals and the 2015 budget. Based on the DMIA expenditure outlined, Ergon Energy expects an adjustment to revenue in year 2 of the regulatory control period 2015-20 of $1.96 million (nominal).[4]

[3] AER (2015), *Preliminary Decision Ergon Energy Determination 2015-16 to 2019-20, Attachment 12 – Demand Management Incentive Scheme,* April 2015.

[4] Further explanation on the DMIA revenue adjustment in 2016-17 is set out in supporting attachment *04.01.00 – (Revised) Compliance with Control Mechanisms*

Table 2: Actual expenditures associated with DMIS, 2010-15

$m (real 2014-15)	2010-11	2011-12	2012-13	2013-14	2014-15
DMIS (Part A, DMIA) 2010-15	0.50	0.58	0.92	0.87	1.00

2.1.3 Application of the incentive in the next period

Table 3 summarises the revenue allowances included in the building blocks for the DMIS for the regulatory control period 2015-20, consistent with the Framework and Approach Paper and the AER's Preliminary Determination. For revenue modelling purposes, Ergon Energy has included the $1 million per annum (in real $2014-15) of DMIA as an individual line item within the revenue adjustment section of the Post Tax Revenue Model, consistent with the AER's Preliminary Determination.[5] To avoid double counting of the allowance, no further adjustments have been made to the revenue model.

Table 3: Estimated revenue allowances associated with DMIS, 2015-20

$m (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20
DMIS (Part A, DMIA) 2015-20	1.00	1.00	1.00	1.00	1.00

2.2 EBSS

2.2.1 Overview

The EBSS seeks to provide a financial incentive for Ergon Energy to improve the efficiency of our operating expenditure and to share any resulting efficiency gains (or losses) with our customers. Any efficiency gains (or losses) are retained by Ergon Energy for five years after the gain (or loss) is realised. This means the EBSS revenue adjustment in the regulatory control period 2015-20 relates to our performance under the EBSS in the regulatory control period 2010-15.

2.2.2 Current period outcomes

The AER has applied an EBSS for operating expenditure to Ergon Energy in the regulatory control period 2010-15 which results in carryover revenue adjustments in the regulatory control period 2015-20.

During 2010-11 and 2011-12, Ergon Energy's operating expenditure exceeded forecast expenditure resulting in carry over amounts that will be attributed to 2015-16 and 2016-17. Ergon Energy implemented a series of initiatives in 2011-12 to reduce operating expenditure, and as a consequence, the operating expenditure in 2012-13 and 2013-14 was reduced significantly compared to allowances. The total operating expenditure in the regulatory control period 2010-15 will be less than the approved operating expenditure allowance for the period.

[5] AER, *Preliminary Decision Ergon Energy Determination 2015-16 to 2019-20, Attachment 1 – Annual Revenue Requirement,* April 2015.

These operating expenditure outcomes, totalling $146.1m, were reflected in the EBSS adjustments included in the ARR for the regulatory control period 2015-20. In its Preliminary Determination, the AER accepted our proposal to apply a positive carryover amount to the regulatory control period 2015-20, but reduced the carryover amount from $146.1m to $130.1m. This was due to the fact that movements in provisions were included in the carryover amounts, and the AER considers that movements in provisions should be excluded from EBSS calculations because they do not represent changes in actual costs incurred in delivering network services. Ergon Energy accepts this decision.

Table 4 summarises the updated revenue adjustments included in the building blocks for the regulatory control period 2015-20 as a result of the application of the EBSS in the regulatory control period 2010-15.

Table 4: Estimated revenue increments and decrements associated with the EBSS, 2015-20

$m (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20
EBSS carry over amounts	33.75	47.94	63.82	(18.31)	0.00

2.2.3 Application of the incentive in the regulatory control period 2015-20

In its Preliminary Determination for the regulatory control period 2015-20, the AER determined that no opex will be subject to the EBSS, as the AER is uncertain whether it will rely on Ergon Energy's revealed costs as the basis for forecasting opex in the regulatory control period 2020-25. The AER considered that applying an EBSS, but setting the forecast on the basis of benchmarking, rather than revealed costs for the regulatory control period 2020-25, may result in Ergon Energy being penalised twice for incremental efficiency losses.

Ergon Energy disagrees with the AER's decision not to apply the EBSS in the regulatory control period 2015-20 as discussed in our *Incentive Scheme – Response* document. As such, 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 2.4.

2.3 STPIS

2.3.1 Overview

The STPIS rewards Ergon Energy when we improve our average service quality to customers and penalises us for a reduction in average service quality to customers. The rewards or penalties are applied by adjusting the amount of allowed revenue in a year in accordance with the mechanism set out in the distribution determination. Ergon Energy currently receives a maximum reward or penalty of +/-2% of its ARR and proposes that this remain at +/-2% in the regulatory control period 2015-20.

2.3.2 Current period outcomes

Ergon Energy is subject to the jurisdictional requirements which specify minimum limits on the reliability of the network, the Minimum Service Standards (MSS). These are in addition to the STPIS under the NER.

The MSS targets are set out in our Distribution Authority[6] and Ergon Energy is required to make best endeavours not to breach these. The jurisdictional MSS are more stringent than the STPIS requirements and as such Ergon Energy has exceeded the targeted performance under the STPIS in the last three years of the 2010-15 period. This has resulted in adjustments to our revenue allowances that will carry over into the next regulatory control period.

Table 5 identifies the 2010-15 period revenue adjustments applicable for the STPIS.

Table 5: Revenue adjustment for the STPIS, 2015-20

$m (real 2014-15)	2010-11	2011-12	2012-13	2013-14	2014-15
STPIS reward (penalty)	0	0	(14.08)	1.90	31.48

Table 6 summarises the revenue adjustments included in our Total Allowed Revenue for the regulatory control period 2015-20 as a result of the application of the STPIS in 2010-15.

Table 6: Estimated revenue adjustments associated with the STPIS, 2015-20[7]

$m (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20
STPIS reward (penalty)	22.11	(9.76)	0.00	0.00	0.00

2.3.3 Application of the incentive in the regulatory control period 2015-20

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

- for the reliability of supply component:
  - set performance targets for both Average Interruption Duration Index and System Average Interruption Frequency Index under the reliability of supply component
  - 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 our 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 Guaranteed Service Levels (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 Australian Energy Market Operator's Value of Customer Reliability (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*

[6] Up until 1 July 2014, the MSS were contained in the Queensland Electricity Industry Code.

[7] Further information on revenue adjustments included in our proposed forecast revenues is set out in in supporting attachment *04.01.00 – (Revised) Compliance with Control Mechanisms.*

Application of STPIS for the 2015-16 to 2019-20 Regulatory Control Period sets out Ergon Energy's proposed STPIS targets for the regulatory control period 2015-20.

In the Preliminary Determination, the AER introduced a cap of ± 1.8 per cent on the reliability of supply component of the STPIS.[8] 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 ARR. For the reasons set out in our *Incentive Schemes – Response* document we have maintained the approach in our Regulatory Proposal that sets the following limits:

- 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.

2.4 CESS

2.4.1 Overview

The CESS seeks to provide incentives to Ergon Energy to improve the efficiency of its capital expenditure allowance and to share any resulting efficiency gains (or losses) with customers. Ergon Energy will receive a reward (or penalty) equivalent to 30 per cent of the net present value of any capital underspends (or overspends) relative to the amount approved by the AER in the distribution determination, adjusted for the financing benefit[9] of the overspend (or underspend). This amount is added (subtracted) from Ergon Energy's regulated revenue in the next regulatory control period.

The AER plans to apply a CESS in conjunction with forecast depreciation to roll forward the RAB. The two mechanisms work together to provide Ergon Energy with a reward of 30 per cent of any underspend and a penalty of 30 per cent of any overspend during the regulatory control period. The AER's desired objective is to:

- encourage more efficient capital expenditure - particularly towards the end of a regulatory control period
- encourage more efficient substitution between capital and operating expenditure.

Ergon Energy notes that 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.

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

[9] The financing benefit is the rate of assets associated with the capital expenditure over or under-spend.

There are three main reasons why declining incentives for efficient capex may be a problem:

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.

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 CCICW, 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 CCICW 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.

Likewise, DNSPs 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 later on 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 a 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.

These outcomes are all avoidable if there is a mechanism, within both the CESS and EBSS, for a DNSP to ask for costs to be excluded where they would have qualified for a pass through. Given the potential costs and downside of the alternative, it is difficult to understand why a carefully framed mechanism for the exclusion of such costs would be resisted.

Ergon Energy does not consider the approach as outlined in the AER's explanatory statement and maintained in its Preliminary Determination to necessarily be in the best long term interests of consumers and submits that the AER should consider the impact of decisions to not apply for pass through on a more flexible basis under the CESS and EBSS, given the schemes' principles are subject to overall assessment of how the DNSP actually meets the relevant expenditure objectives, criteria and factors at a given point in time.

Ergon Energy is not proposing that the above two areas of expenditure be subject to automatic exclusions under the CESS. Rather Ergon Energy proposes that in assessing the operation of the scheme, the AER properly and fully consider whether any overspend or underspend of capital attributable to events that qualify as a pass through or that relate to CCICW expenditure are considered against the capital objectives, criteria and factors under the NER in assessing whether the capital spend under consideration is efficient or inefficient. Ergon Energy considers that such flexibility of assessment is both consistent with the Rules, the EBSS and the CESS itself.
Ergon Energy notes that the impacts we have referred to above in terms of pass through events and CCICW expenditure are consistent with the detailed list of factors and types of matters that should be taken into account under the Stage 2 analysis contained the CESS guidelines.

The AER did not support our proposals for exclusions for these two matters in its Preliminary Determination. It 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.

For these reasons set out above and in our *Incentive Schemes – Response* document, Ergon Energy has maintained our approach to exclusions in the revised Regulatory Proposal. Further, Ergon Energy proposes that, should the AER decide not to apply the EBSS in the regulatory control period 2015-20, the CESS should also not apply as explained in our *Incentive Schemes – Response* document.

2.4.2 Application of the incentive in the regulatory control period 2015-20

In its Preliminary Determination, the AER decided that the CESS will commence and be applied to the results for the regulatory control period 2015-20 but will not affect customers until the regulatory control period 2020-25.

To determine the incentive or penalty to be shared between Ergon Energy and our customers, the AER will calculate efficiency gains or efficiency losses, using the following method:

- calculate efficiency gains and losses in net present value terms for each year of the regulatory control period and then calculate the total efficiency gain/loss for the regulatory control period
- apply a sharing factor to the total efficiency gain/loss to calculate Ergon Energy’s share of the gain/loss
- calculate financing benefits/costs that accrue through the regulatory control period
- calculate the CESS reward/penalty by subtracting the financing benefit/cost that has accrued from our share of the total efficiency gain/loss.

Ergon Energy accepts the AER’s Preliminary Determination to apply the CESS during the regulatory control period 2015-20, subject to the EBSS also applying. As noted above, if the EBSS is not applied, the CESS should also not apply.

2.5 Small Scale Incentive Scheme

2.5.1 Overview

The Small Scale Incentive Scheme (SSIS) is an incentive scheme that the AER can apply to a DNSP as part of the distribution determination and is applicable only to that DNSP for that determination. The AER is required to advise of its intention to apply a SSIS during the Framework and Approach process.

2.5.2 Application of the incentive in the regulatory control period 2015-20

The AER advised in its Framework and Approach Paper for the regulatory control period 2015-20 that it is has not developed this scheme and therefore proposed to not apply this scheme to Ergon Energy in the regulatory control period 2015-20. This was also reflected in the Preliminary Determination, with no SSIS applied. Ergon Energy supports this decision.