Chapter 4: Controls on revenue and prices for Standard Control Services

Introduction and summary of changes

The AER places controls on the amount of revenue we are allowed to collect for our Standard Control Services through a revenue cap, consistent with the arrangements in the NER.

This chapter details Ergon Energy's proposal for how the form of control will be translated into charges for customers. These controls ultimately specify how Ergon Energy can propose prices each year, consistent with the revenue cap, taking into account adjustments allowed for matters such as inflation, incentive schemes, any under or over recoveries from previous years, or any cost pass through amounts.

Ergon Energy has generally maintained the positions set out in our October Regulatory Proposal. We have reviewed our proposed contingent projects and pass through events, and made changes as necessary. We have also proposed changes to the unders and overs accounts, which will assist us in managing any price volatility during the period.

Customer benefits

In considering the pricing matters in this chapter we have looked to minimise price volatility where ever possible.

After reducing charges for the use of our network in 2015-16, we're targeting to keep charges overall at 2014-15 levels for the remaining four years out to 2020.

4. Controls on revenue and prices for Standard Control Services

4.1 Background

For Standard Control Services, the AER will place controls on the amount of revenue we can collect for these services (a 'revenue cap') consistent with the arrangements in the NER. This will determine the cap on revenue each year, as well as how Ergon Energy will propose prices consistent with the revenue cap, taking into account adjustments allowed for matters such as inflation, incentive schemes, any under or over recoveries from previous years, or any cost pass through amounts.

This chapter details Ergon Energy's proposal for how the form of control will be translated into charges for customers and considers a range of other pricing matters that need to be addressed as part of the Distribution Determination. These include:

- how prices and/or revenues will be controlled over the regulatory control period 2015-20,[49] including the form of the control mechanism[50] and the X-factor[51]
- how compliance with the control mechanism will be demonstrated[52]
- how customers will be assigned to tariff classes and, if required, be re-assigned between tariff classes[53]
- how designated pricing proposal charges (or Transmission Use of System (TUOS) charges) will be recovered, including any unders and overs adjustments[54]
- how Ergon Energy will report on the recovery of any jurisdictional scheme amounts, including any unders and overs adjustment for each scheme.[55]

Additionally, this chapter outlines other potential adjustments to the allowable revenue from factors such as contingent projects and pass through events.

4.2 Application of the standard control formula

The AER has departed from the Standard Control Services formula set out in its Framework and Approach Paper. We do not support this departure, as the formula cannot be applied in practice and the AER has not justified why a departure is necessary. Our submission in response to the AER's Preliminary Determination provides further reasoning and explanation why we did not mirror the AER's decision in our revised Regulatory Proposal.

Ergon Energy has retained the formula contained in our October Regulatory Proposal, which was consistent with the Framework and Approach Paper. However, we have made some changes to the formula descriptions to reflect our proposed application of the formula. We have also corrected for a minor equation error.

[49] NER, clause 6.2.5(a).
[50] NER, clause 6.12.1(11).
[51] NER, clause 6.12.1(12).
[52] NER, clause 6.12.1(13).
[53] NER, clause 6.12.1(17).
[54] NER, clause 6.12.1(19).
[55] NER, clause 6.12.1(20).

In line with the Framework and Approach Paper, Ergon Energy proposes that the following Standard Control Services formula should apply in the regulatory control period 2015-20:

Revenue cap (as determined by the PTRM):

$$(1)\ AR_t = AR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$$

Total allowed revenue (including adjustments):

$$(2)\ TR_t = AR_t + I_t + B_t + C_t$$

$$(3)\ TR_t \geq \sum_{i=1}^{n} \sum_{j=1}^{m} p_{ij}^t q_{ij}^t \qquad i = 1, \dots, n \text{ and } j = 1, \dots, m \text{ and } t = 1, \dots, 5$$

Where:

AR_t is the allowed revenue for regulatory year t. For the first year of the regulatory control period 2015-20, this amount will be equal to the smoothed revenue requirement for 2015-16 set out in the PTRM approved by the AER. The subsequent years' allowed revenue is determined by adjusting the previous year's allowed revenue for CPI and the X-factor

ΔCPI_t is the annual percentage change in the Australian Bureau of Statistics (ABS) CPI All Groups, Weighted Average of Eight Capital Cities from December in year t–2 to December in year t–1

X_t is the X-factor for each year of the regulatory control period 2015-20 as determined in the PTRM, and annually revised for the return on debt update in accordance with the formula specified in the return on debt appendix I calculated for the relevant year

TR_t is the total revenue allowable in year t

I_t is the sum of adjustments related to:

- the final carryover amount from the application of the DMIS from the 2010–15 distribution determination. This amount will be deducted from/added to allowed revenue in the 2016-17 pricing proposal
- the STPIS. This amount will be deducted from/added to allowed revenues in regulatory year t based on the application of the S-factor

B_t is the sum of adjustments related to:

- any under or over-recoveries relating to capital contributions and shared assets from 2013-14 and 2014-15
- the balance of the DUOS unders and overs account with respect to regulatory year t

C_t is the sum of adjustments related to:

- feed-in tariff cost pass through amounts relating to 2013-14 and 2014-15
- amounts relating to the occurrence of any of the prescribed and nominated cost pass through events
- other one-off adjustments approved by the regulator in year t

p_{ij}^t is the price of component i of tariff j in year t

q_{ij}^t is the forecast quantity of component i of tariff j in year t.

4.2.1 Components of the revenue cap and total allowed revenue formula

The following points are made in respect of the proposed formula:

- Adjustments associated with the trailing average cost of debt will be made in the X_t component of the AR_t formula (refer to our supporting document *04.01.00 – (Revised) Compliance with Control Mechanisms*).
- Based on the previous and proposed incentive scheme arrangements, I_t will incorporate adjustments relating to:
  - STPIS. This includes rewards or penalties associated with our performance under the scheme in 2013-14 and 2014-15, which will result in adjustments in 2015-16 and 2016-17, respectively. It also encompasses rewards or penalties relating to our performance under the scheme in the first three years of the regulatory control period 2015-20, which will generally result in adjustments two years after the respective performance year.
  - DMIS. Under the current DMIS,[56] the AER will calculate a total carryover amount to account for any amount of allowance unspent or not approved over the regulatory control period 2010-15 and the time value of money accrued/lost as a result of the expenditure profile selected by Ergon Energy. The final carryover amount will be deducted from/added to the allowed revenue in 2016-17.
- B_t will encompass:
  - any under or over-recoveries relating to capital contributions and shared assets from 2013-14 and 2014-15
  - the DUOS under and over-recovery adjustments approved to be passed through in the relevant pricing year.
- C_t will include adjustments associated with:
  - FiT cost pass through amounts relating to 2013-14 and 2014-15
  - amounts relating to the occurrence of any of the prescribed and nominated cost pass through events (refer to Section 4.4)
  - other one-off revenue adjustments approved by the AER. This would be used in limited circumstances, and only to the extent that such adjustments are unable to be accounted for within other parameters of the revenue cap formula. For example, in the regulatory control period 2015-20, this adjustment could (if required) encompass any other true-up adjustments which may be necessary between the AER's Preliminary Determination and Substitute Determination.

Further information on our proposed treatment of the revenue cap components in the regulatory control period 2015-20 is contained in our supporting document *04.01.00 – (Revised) Compliance with Control Mechanisms.*

[56] AER (2008), Demand Management Incentive Scheme, Energex, Ergon Energy and ETSA Utilities 2010-15, October 2008, p8.

4.3 Pricing arrangements

Clause 6.18 of the NER details the distribution pricing rules to apply to Ergon Energy's tariffs and tariff classes related to Direct Control Services in the regulatory control period 2015-20.

The following sections set out the approaches to setting tariffs that Ergon Energy intends to adopt. Ergon Energy is required to annually submit a Pricing Proposal to the AER, consistent with the requirements under clause 6.18.2 of the NER.[57]

4.3.1 Allocation of revenue to tariffs

The process for allocating and converting the total allowed revenue to network tariffs for various customers groups is described in detail in our website publication *Information Guide for Standard Control Services Pricing*.[58]

At a high level, the total allowed revenue is allocated to the three pricing zones (being East, West and Mount Isa) and the zonal costs are apportioned to different asset categories within each zone. The costs within the zones are then assigned to our four network user groups and converted into network tariffs that recover the costs. TUOS charges and jurisdictional scheme charges are then allocated to customers.

In accordance with clause 6.1.4 of the NER, Ergon Energy does not charge network users DUOS charges for the export of electricity generated by the user into the distribution network. However, charges for the provision of connection services may apply.

4.3.2 Side constraints

The AER's Preliminary Determination sets out the side constraints formula that will apply to Ergon Energy in the regulatory control period 2015-20. Ergon Energy is generally comfortable with the approach taken by the AER. However, we have proposed some changes in our revised Regulatory Proposal to reflect the revenue cap formula set out above.

Clause 6.18.6(b) of the NER requires the expected weighted average revenue to be raised from a Standard Control Services tariff class to not exceed the corresponding expected weighted average revenue from the preceding year by more than a permissible percentage (side constraint).

Under clause 6.18.6(d) of the NER the following recovery of revenue is to be disregarded in deciding whether the permissible percentage (side constraint) has been exceeded in a particular regulatory year:

- a variation to the distribution determination as a result of cost pass through under clause 6.6 of NER
- a revocation and substitution of distribution determination for wrong information or error under clause 6.13 of NER
- pass through of designated pricing proposal charges
- pass through of jurisdictional scheme amounts for approved jurisdictional schemes

[57] Our 2015-16 Pricing Proposal was submitted to the AER on 21 May 2015 and was based on the outcomes of the AER's Preliminary Determination.

[58] Available at www.ergon.com.au/networktariffs.

- any increase in the ARR as a result of changes to the allowed rate of return (effected through the application of the control mechanism formula specified in the distribution determination).

We propose to apply the following side constraints formula:

$$\frac{(\sum_{j=1}^{m} d_t^j q_t^j)}{(\sum_{j=1}^{m} d_{t-1}^j q_t^j)} \leq (1+\Delta CPI_t)(1-X_t)(1+2\%) \pm I_t \pm B_t \pm C_t$$

where each tariff class has up to ‘m’ components, and where:

d_t^j is the proposed price for component ‘j’ of the tariff class for year t

d_{t-1}^j is the price for component ‘j’ of the tariff class in year t–1

q_t^j is the forecast quantity of component ‘j’ of the tariff class in year t

ΔCPI_t is the annual percentage change in the ABS CPI All Groups, Weighted Average of Eight Capital Cities from December in year t-2 to December in year t-1

X_t is the smoothing factor determined in accordance with the PTRM as approved in the AER's final decision, and annually revised for the return on debt update in accordance with the formula specified in the return on debt appendix I calculated for the relevant year. If X>0, then X will be set equal to zero for the purposes of the side constraint formula

I_t is the sum of adjustments related to:

- the final carryover amount from the application of the DMIS from the 2010–15 distribution determination. This amount will be deducted from/added to allowed revenue in the 2016-17 pricing proposal
- the STPIS. This amount will be deducted from/added to allowed revenues in regulatory year t based on the application of the S-factor

B_t is the sum of adjustments related to:

- any under or over-recoveries relating to capital contributions and shared assets from 2013-14 and 2014-15
- the balance of the DUOS unders and overs account with respect to regulatory year t

C_t is the sum of adjustments related to:

- feed-in tariff cost pass through amounts relating to 2013-14 and 2014-15
- amounts relating to the occurrence of any of the prescribed and nominated cost pass through events
- other one-off adjustments approved by the regulator in regulatory year t.

Further information is set out in our supporting document *04.01.00 – (Revised) Compliance with Control Mechanisms*.

4.3.3 DUOS unders and overs account

The AER's Preliminary Determination requires Ergon Energy to maintain a DUOS unders and overs account. Ergon Energy supports this decision. However, we maintain our preference for tolerance limits to allow for the smoothing of volatility within the regulatory control period. We also now propose to include an estimate of the closing balance in year t-1 in the DUOS unders and overs account to alleviate concerns we have if tolerance limits are no longer allowed.

Consistent with the AER's Preliminary Determination and the regulatory control period 2010-15, Ergon Energy proposes to report to the AER annually in our Pricing Proposal on the recovery of DUOS from our network tariffs, and make adjustments to subsequent pricing periods to account for over or under recovery of those charges.

Ergon Energy's preference is for tolerance limits to be applied. However, if the AER does not accept this, we propose to apply a DUOS unders and overs mechanism based on the audited closing balance in year t-2 and estimate of the closing balance in year t-1. The over or under recovery in year t-1 would be recovered via an adjustment in year t.

Further information can be found in our supporting document *04.01.00 – (Revised) Compliance with Control Mechanisms*.

4.3.4 Assignment of customers to tariff classes

The AER's proposed procedures are generally consistent with those applying in the regulatory control period 2010-15. While Ergon Energy accepts many aspects of the procedures, there are a number of matters which we believe the AER should address or provide clarification on. We have summarised these concerns in our submission to the AER's Preliminary Determination. We also note the Queensland Energy and Water Ombudsman is unable to investigate assignment and reassignment objections under the Energy and Water Ombudsman Act 2006 (Qld).

Assignment or reassignment of customers to Ergon Energy's Standard Control Service tariff classes occurs as result of:

- new connections to the network
- existing customers applying for increased capacity on the network
- a change in the customer's National Metering Identifier classification
- annual review as part of the process for developing and submitting the Pricing Proposal for approval by the AER
- requests for a review of the assigned network tariff or tariff class by either a customer and/or retailer.

Our *Information Guide for Standard Control Services Pricing*[59] sets out the current procedures for assigning or reassigning customers to tariff classes, as well as reviewing the basis on which a customer is charged. These procedures are consistent with the Preliminary Determination and the

[59] Available at www.ergon.com.au/networktariffs.

principles governing assignment or re-assignment of customers to tariff classes set out in clause 6.18.4 of the NER.

Ergon Energy proposes to apply the procedures set out in the Preliminary Determination throughout the remainder of the regulatory control period 2015-20, subject to the changes proposed in our supporting submission *SCS Building Blocks, Control Mechanism and Pricing – Response.*

4.3.5 Designated pricing proposal charges

The AER's Preliminary Determination requires Ergon Energy to maintain a TUOS unders and overs account. Ergon Energy supports this decision. However, in the event tolerance limits are not accepted for DUOS under and over recoveries, consistent with the DUOS unders and overs account, we propose to include an estimate of the closing balance in year t-1.

The AER also determined charges associated with Chumvale and non-prescribed Powerlink connection points should remain designated pricing proposal charges, despite the cessation of the transitional provision on 1 July 2015. We have applied the AER's decision in our revised Regulatory Proposal.

Under clause 6.18.7 of the NER, Ergon Energy's pricing proposal must provide for tariffs designed to pass on to retail customers the designated pricing proposal charges to be incurred by us for TUOS services. The NER defines designated pricing proposal charges as any of the following:

- charges for prescribed exit services, prescribed common transmission services and prescribed TUOS services
- avoided customer TUOS charges
- charges for distribution services provided by another DNSP
- charges or payments specified in clause 11.39 of the NER.

The amount to be passed on for a particular regulatory year must not exceed the estimated amount of the TUOS charges adjusted for over and under recovery.

Clause 6.18.7(c) of the NER sets out how the over and under recovery amount must be calculated. Specifically:

- it must be consistent with the method determined in the AER's Distribution Determination
- the amount must be no more and no less than the TUOS charges Ergon Energy incurs
- it must adjust for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant Distribution Determination for the relevant regulatory year.

Consistent with the AER's Preliminary Determination, Ergon Energy proposes to apply a TUOS unders and overs mechanism in the regulatory control period 2015-20. That is, we will report to the AER annually in our Pricing Proposal on the recovery of TUOS from our network tariffs, and make adjustments to subsequent pricing periods to account for any under or over recovery of those charges.

Ergon Energy considers that consistency in unders and overs recovery arrangements is appropriate. On this basis, we propose to apply an unders and overs mechanism, similar to DUOS, based on the audited closing balance in year t-2 and estimate of the closing balance in year t-1. In addition to the actual under/over recovery of amounts in t-2, the estimated under or over recovery in year t-1 would be recovered via an adjustment in year t. Our supporting document[60] includes details of our reporting and calculation of designated pricing proposal charges.

Ergon Energy notes a transitional definition of designated pricing proposal charges applied to Ergon Energy in the regulatory control period 2010-15.[61] Specifically, designated pricing proposal charges included:

- charges levied on Ergon Energy for use of the 220kV network which supplies the Cloncurry township as approved by the AER in its Distribution Determination 2010-15
- charges levied by Powerlink on Ergon Energy for entry services and exit services at the four connection points, being Queensland Nickel, Stoney Creek, King Creek and Oakey Town.[62]

Consistent with the AER's position in the Preliminary Determination, Ergon Energy will treat the charges levied on Ergon Energy for the use of the 220kV network that supplies the Cloncurry township and for entry and exit services at the three non-prescribed connection points as designated pricing proposal charges. These costs will therefore be reflected in TUOS charges.

4.3.6 Jurisdictional schemes

The AER did not accept our proposal to apply a two year lag to recover the amounts associated with FiT payments. The AER's Preliminary Determination recovers two amounts related to FiT recoveries in 2015-16 and 2016-17. Ergon Energy has not revised our proposal in relation to this decision. We have revised our proposal in order to adopt an overs and unders recovery arrangement consistent with what we proposed for DUOS and TUOS.

Clause 6.18.7A of the NER states that a Pricing Proposal must provide for tariffs designed to pass on to customers a DNSP's jurisdictional scheme amounts for approved jurisdictional schemes. In Queensland, the Solar Bonus Scheme[63] will apply as a jurisdictional scheme in the regulatory control period 2015-20.

The amount to be passed on to customers for a particular regulatory year must not exceed the estimated amount of the jurisdictional scheme amounts for a DNSP's approved jurisdictional schemes adjusted for over or under recovery.[64]

Clause 6.18.7A(c) of the NER details how the over and under recovery amount must be calculated. Specifically:

- it must be consistent with the method determined in the AER's Distribution Determination, or where no such method has been determined, with the method determined by the AER in the relevant Distribution Determination in respect of TUOS charges
- the amount must be no more and no less than the jurisdictional scheme amounts Ergon Energy incurs

[60] *04.01.01 – (Revised) Designated Pricing Proposal Charges*.

[61] NER, clause 11.39.6.

[62] There will only be three non-prescribed connection points in the regulatory control period 2015-20.

[63] Pursuant to section 44A of the *Electricity Act 1994 (Qld)*.

[64] NER, clause 6.18.7A(b).

- it must adjust for an appropriate cost of capital that is consistent with the allowed rate of return used in the relevant Distribution Determination for the relevant regulatory year.

Solar Bonus Scheme

The costs of the FiT paid under the Solar Bonus Scheme were treated as operating expenditure for the regulatory control period 2010-15, with the differences between the forecast FiT payments and actual FiT payments being a nominated pass through event. Once the cost pass through amounts are approved, Ergon Energy adjusted our annual revenue allowances to pass through these amounts to customers in our DUOS charges.

In practice, this means there is a two year lag between the year in which the payments are made, and the year in which adjustments are made to prices to fully recover amounts associated with FiT payments. For example, in our 2014-15 DUOS charges, amounts were factored in to recover the under-recovery of actual FiT payments made in the 2012-13 year.

In the regulatory control period 2015-20, these costs will be recovered as jurisdictional scheme amounts consistent with clause 6.18.7A(e)(1)(iii) of the NER.

We propose that the recovery of the costs be delayed by two years, such that the jurisdictional scheme amount for 2015-16 would be recovered in 2017-18, the jurisdictional scheme amount for 2016-17 would be recovered in 2018-19, and so on.

This approach will avoid recovery of both a FiT cost pass through amount and jurisdictional scheme amount in a single year, which would create price shocks for customers. For example, the under-recovery of actual FiT payments made in the 2013-14 year would be recovered in 2015-16 and the jurisdictional scheme amount for 2015-16 would be recovered in 2017-18, instead of both being recovered in 2015-16.

Table 14 sets out the forecast FiT payments under the Solar Bonus Scheme and the timing of the proposed recovery of the jurisdictional scheme amounts.

Table 14: Forecast jurisdictional scheme amounts, Solar Bonus Scheme[65]

$m (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20
Forecast feed-in tariff payments	114.2	114.4	114.3	114.0	113.8
Proposed recovery of jurisdictional scheme amounts	114.2	(122.7)	131.8	132.0	131.9

In order to be consistent with the under/over recovery of TUOS amounts, if tolerance limits for DUOS under and over recoveries are not accepted, we also propose to apply an unders and overs mechanism to jurisdictional schemes, based on the audited closing balance in year t-2 and estimate of the closing balance in year t-1. In addition to the actual under/over recovery in t-2, the estimated under or over recovery in year t-1 would be recovered via an adjustment in year t.

[65] In order to implement Ergon Energy's two-year lag approach following the implementation of 2015-16 prices with a jurisdictional scheme component, we propose to:

- treat the recovery of jurisdictional scheme amounts through prices as an over-recovery in 2015-16
- adjust for this over-recovery when setting 2016-17 prices, by netting the 2015-16 jurisdictional scheme payments from the pass through of 2014-15 FiT payments
- recover the 2015-16 jurisdictional scheme payments through our 2017-18 prices in accordance with our proposed two-year lag.

More detailed information on the estimation of the forecast jurisdictional scheme amounts for the Solar Bonus Scheme, and how we propose to recover these amounts, is provided in our supporting document *04.01.02 – (Revised) Jurisdictional schemes*.

4.4 Proposed pass through events

The AER accepted our natural disaster and insurance cap events. However, it made some changes to the definitions proposed by Ergon Energy. We generally accept the definitional change for the natural disaster event. However, we propose the re-inclusion of 'cyclone' in the definition. We agree with the definitional change for insurance cap events. Our proposal has been amended accordingly.

The AER did not accept our proposed retail separation, isolated network separation or insurance events. For the latter, the AER instead introduced an insurer's credit risk event. We agree with the introduction of an insurer's credit risk event to replace the proposed insurance event. However, we disagree with the AER's position on our proposed retail separation and isolated network separation events and have therefore not made changes in our revised Regulatory Proposal.

Given the recent announcement to merge Ergon Energy, Energex and Powerlink, we have also proposed a new merger event.

A cost pass through may occur within a regulatory control period when a pre-defined event occurs which materially increases or decreases a DNSP's costs to deliver Direct Control Services. In these circumstances, the AER may approve a positive (negative) pass through amount under the cost pass through provisions in the NER, effectively adjusting the approved revenue of a DNSP during a regulatory control period.

There are a number of pre-defined events set out in clause 6.6.1(a1) of the NER. In addition, the NER also provides that the Distribution Determination may specify any other event as a pass through event.

Ergon Energy proposes the following events be specified as pass through events for the regulatory control period 2015-20:

- natural disaster event
- insurance cap event
- insurer's credit risk event
- retail separation event
- isolated networks separation event
- merger event.

Ergon Energy considers these events meet the nominated pass through event considerations set out in the NER. Our proposed definitions and reasons why these events should be considered pass through events is contained in our supporting document *04.01.03 – (Revised) Nominated cost pass through events*.

4.5 Contingent projects

Ergon Energy proposed one contingent project in our October Regulatory Proposal, as well as a general contingent project relating to large customer connections. The AER did not accept our proposal. We note the AER's decision and have updated our revised Regulatory Proposal accordingly. We have not identified any new contingent projects.

Contingent projects are significant projects that are reasonably required to meet the capital expenditure objectives if a given trigger event occurs. In order to be considered a contingent project, the capital expenditure must be at least $30 million or 5% of Ergon Energy's ARR for the first year of the regulatory control period, whichever is the larger amount.

Ergon Energy undertook an assessment process to identify potential contingent projects. This assessment:

- identified those projects in Ergon Energy's Network Capital Plan whose forecast capital expenditure exceeded the contingent project threshold
- for those projects identified above the threshold, considered whether the project:
    - has an appropriately defined trigger event
    - is reasonably required to meet the capital expenditure objectives
    - reasonably reflects the capital expenditure criteria.

Using this assessment approach, Ergon Energy did not identify any projects for consideration as a contingent project.

4.6 Indicative prices

The indicative prices for selected tariffs have been updated to reflect our revised ARRs and more up-to-date information on expected annual revenue adjustments.

The following tables set out indicative prices for selected Standard Asset Customer (SAC)[66] tariffs for each year of the regulatory control period 2015-20, as required under clause 6.8.2(c)(4) of the NER. These indicative prices are expressed in nominal terms.

Our response to the RIN provides indicative prices for our larger customers.[67]

[66] Typically customers with energy consumption less than 4GWh per annum. This includes customers with micro generation facilities (such as small scale photovoltaic generators) that have similar service connection and usage profiles as other SACs without such facilities. SACs are split into two sub-groups: SAC Small (i.e. those customers who consume less than 100MWh per annum) and SAC Large (i.e. those customers who consume 100MWh or more per annum). For more information on our SAC network tariffs, refer to our *Information Guide for Standard Control Services Pricing* available at http://www.ergon.com.au/networktariffs.

[67] Refer to templates 7.6 and 7.7. Note Ergon Energy has not updated these indicative prices for the purposes of this revised Regulatory Proposal.

Table 15: Indicative prices for SAC Small – Inclining Block Tariff (IBT) Residential – East, 2014-20

IBT Residential (ERIB)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	1.52	1.25	1.61	1.51	1.53	1.55
Volume Block 1 ($/kWh)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Volume Block 2 ($/kWh)	0.1531	0.0882	0.1138	0.1069	0.1082	0.1095
Volume Block 3 ($/kWh)	0.1631	0.1182	0.1525	0.1432	0.1450	0.1467

Table 16: Indicative prices for SAC Small – Seasonal Time-of-Use (TOU) Energy Residential – East, 2014-20

Seasonal TOU Energy Residential (ERTOU)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	1.52	1.25	1.61	1.51	1.53	1.55
Volume Peak ($/kWh)	0.5519	0.3181	0.3262	0.3345	0.3430	0.3518
Volume Shoulder ($/kWh)	0.2666	0.3181	0.4104	0.3854	0.3902	0.3949
Volume Off Peak ($/kWh)	0.0957	0.0506	0.0653	0.0613	0.0621	0.0628

Table 17: Indicative prices for SAC Small – Seasonal TOU Demand Residential – East, 2014-20

Seasonal TOU Demand Residential (ERTOUD)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	n/a	0.00	0.00	0.00	0.00	0.00
Volume Peak ($/kWh)	n/a	0.0313	0.0404	0.0379	0.0384	0.0389
Volume Off Peak ($/kWh)	n/a	0.0313	0.0404	0.0379	0.0384	0.0389
Actual Demand Peak ($/kWh)	n/a	64.821	66.474	68.169	69.907	71.690
Actual Demand Off Peak ($/kWh)	n/a	12.000	15.484	14.541	14.721	14.898

Table 18: Indicative prices for SAC Small – IBT Business – East, 2014-20

IBT Business (EBIB)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	1.52	1.25	1.61	1.51	1.53	1.55
Volume Block 1 ($/kWh)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Volume Block 2 ($/kWh)	0.1538	0.1085	0.1400	0.1315	0.1331	0.1347
Volume Block 3 ($/kWh)	0.1638	0.1385	0.1787	0.1679	0.1699	0.1720

Table 19: Indicative prices for SAC Small – Seasonal TOU Energy Business – East, 2014-20

Seasonal TOU Energy Business (EBTOU)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	1.52	1.25	1.61	1.51	1.53	1.55
Volume Peak ($/kWh)	0.4140	0.2895	0.2968	0.3044	0.3122	0.3201
Volume Shoulder ($/kWh)	0.3066	0.2895	0.3735	0.3507	0.3551	0.3594
Volume Off Peak ($/kWh)	0.1236	0.0942	0.1215	0.1141	0.1156	0.1170

Table 20: Indicative prices for SAC Small – Seasonal TOU Demand Business – East, 2014-20

Seasonal TOU Demand Business (EBTOUD)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	n/a	0.00	0.00	0.00	0.00	0.00
Volume Peak ($/kWh)	n/a	0.0284	0.0366	0.0344	0.0348	0.0352
Volume Off Peak ($/kWh)	n/a	0.0284	0.0366	0.0344	0.0348	0.0352
Actual Demand Peak ($/kWh)	n/a	80.554	82.608	84.715	86.875	89.090
Actual Demand Off Peak ($/kWh)	n/a	12.000	15.484	14.541	14.721	14.898

Table 21: Indicative prices for SAC Large – Demand Large – East, 2014-20

Demand Large (EDLT)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	419.28	369.99	522.88	475.00	477.83	480.53
Actual Demand kW ($/kW/month)	28.78	23.27	23.86	24.47	25.09	25.73
Volume ($/kWh)	0.0055	0.0050	0.0071	0.0064	0.0065	0.0065

Table 22: Indicative prices for SAC Large – Demand Medium – East, 2014-20

Demand Medium (EDMT)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	140.45	135.61	191.65	174.10	175.14	176.13
Actual Demand kW ($/kW/month)	30.08	27.15	27.84	28.55	29.28	30.03
Volume ($/kWh)	0.0055	0.0037	0.0053	0.0048	0.0048	0.0048

Table 23: Indicative prices for SAC Large – Demand Small – East, 2014-20

Demand Small (EDST)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	38.73	37.96	53.65	48.73	49.02	49.30
Actual Demand kW ($/kW/month)	33.63	32.64	33.47	34.33	35.20	36.10
Volume ($/kWh)	0.0055	0.0042	0.0059	0.0053	0.0054	0.0054

Table 24: Indicative prices for SAC Large – Seasonal TOU Demand – East, 2014-20

Seasonal TOU Demand (ESTOUD)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	n/a	32.00	45.22	41.08	41.33	41.56
Volume Peak ($/kWh)	n/a	0.0000	0.0000	0.0000	0.0000	0.0000
Volume Off Peak ($/kWh)	n/a	0.0336	0.0475	0.0432	0.0434	0.0437
Actual Demand Peak ($/kWh)	n/a	47.83	49.05	50.30	51.58	52.90
Actual Demand Off Peak ($/kWh)	n/a	12.94	18.28	16.61	16.71	16.80

4.7 Supporting documentation

The following documents referenced in this chapter accompany our Regulatory Proposal:

Name	Ref	File name
(Revised) Compliance with Control Mechanisms	04.01.00	(Revised) Compliance with control mechanisms
(Revised) Designated pricing proposal charges	04.01.01	(Revised) Designated pricing proposal charges
(Revised) Jurisdictional schemes	04.01.02	(Revised) Jurisdictional schemes
(Revised) Nominated cost pass through events	04.01.03	(Revised) Nominated pass through events
Regulatory Information Notice	N/A	Our response to the AER's RIN is contained in a number of files attached to this proposal. Information provided in our RIN is correct as at the time of our October Regulatory Proposal, unless otherwise stated.