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

Introduction

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.

Customer benefits

In considering the pricing matters in this chapter we have looked to minimise price volatility where ever possible, deliver price relief at the beginning of the period and keep increases overall in network charges on average under inflation.

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,[40] including the form of the control mechanism[41] and the X-factor[42]
- how compliance with the control mechanism will be demonstrated[43]
- how customers will be assigned to tariff classes and, if required, be re-assigned between tariff classes[44]
- how designated pricing proposal charges (or Transmission Use of System (TUOS) charges) will be recovered, including any unders and overs adjustments[45]
- how Ergon Energy will report on recovery of any jurisdictional scheme amounts, including any unders and overs adjustment for each scheme.[46]

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 Framework and Approach Paper indicated that the Standard Control Services formula that would apply in the next regulatory control period would take the following form:

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):

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

$$TR_t = \sum_{i=1}^{n} \sum_{j=1}^{m} p_{ij}^t q_{ij}^t \qquad i = 1, \ldots, n \text{ and } j = 1, \ldots, m \text{ and } t = 1, \ldots, 5$$

[40] NER, clause 6.2.5(a).
[41] NER, clause 6.12.1(11).
[42] NER, clause 6.12.1(12).
[43] NER, clause 6.12.1(13).
[44] NER, clause 6.12.1(17).
[45] NER, clause 6.12.1(19).
[46] NER, clause 6.12.1(20).

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 next regulatory control period as determined in the PTRM

TR_t is the total revenue allowable in year t

I_t is the sum of incentive scheme adjustments in year t

B_t is the sum of annual adjustment factors in year t. Likely to incorporate but not limited to adjustments for the overs and unders account

C_t is the sum of adjustments likely to incorporate but not limited to pass through events and feed-in tariff payments that are not made under jurisdictional schemes

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 – Compliance with Control Mechanisms*).
- Based on the current and proposed incentive scheme arrangements, I_t is likely to 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 next regulatory control period, which will generally result in adjustments two years after the respective performance year.
    - DMIS. Under the current DMIS,[47] the AER will calculate a total carryover amount to account for any amount of allowance unspent or not approved over the current regulatory control period 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 allowed revenue in 2016-17.

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

- 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 is expressed quite broadly in the formula for total revenue and is likely to be used for a number of adjustments throughout the regulatory control period. We consider that it should 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 next regulatory control period, 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 next regulatory control period is contained in our supporting document *04.01.00 – Compliance with Control Mechanisms.*

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 next regulatory control period.

The following sections set out the approaches to setting tariffs that Ergon Energy intends to adopt. Ergon Energy will submit a full Pricing Proposal to the AER following the publication of the AER's Preliminary Determination, consistent with the requirements under clause 6.18.2 of the NER.

4.3.1 Allocation of ARR to tariffs

The process for allocating and converting the ARR to network tariffs for various customers groups is described in detail in our website publication *Information Guide for Standard Control Services Pricing*.[48]

At a high level, the ARR 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.

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

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

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

In section 4.5.2 of the AER's 2010-15 Final Distribution Determination, the AER provided further guidance on the application of side constraints, and outlined a formula that Ergon Energy was to use to demonstrate that proposed DUOS prices set through the annual Pricing Proposal process met the permissible percentage.

The AER's Framework and Approach Paper did not cover matters of detail relating to annual Pricing Proposals (such as the side constraint formula). However, Ergon Energy expects the new NER requirements for the allowed rate of return, as well as changes the AER has made to the revenue cap formula will have a consequential impact on the side constraint formula.

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

4.3.3 DUOS unders and overs account

Ergon Energy currently reports to the AER annually in our Pricing Proposal on the recovery of DUOS from our network tariffs, and makes adjustments to subsequent pricing periods to account for over or under recovery of those charges in accordance with the DUOS unders and overs account set out in the Distribution Determination 2010-15.

Ergon Energy proposes to apply a principles-based approach in the next regulatory control period which seeks to balance the need to:

- reduce the amount of over or under recoveries over time
- minimise volatility for prices in the short or longer term so as not to exacerbate future over or under recoveries.

Included in our proposal is an approach that allows for flexibility if future over or under recoveries can be reasonably foreseen. Finally, we propose that the AER should allow clearance of under or over balances to span regulatory control periods (where appropriate). Further information can be found in our supporting document *04.01.00 – Compliance with Control Mechanisms*.

4.3.4 Assignment of customers to tariff classes

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*[49] 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 processes have been effective during the current regulatory control period and are consistent with the principles governing assignment or re-assignment of customers to tariff classes set out in clause 6.18.4 of the NER. Therefore, we propose to continue to apply these procedures in the next regulatory control period.

4.3.5 Designated pricing proposal charges

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.

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

Our supporting document[50] includes details of our reporting and calculation of designated pricing proposal charges. Ergon Energy currently reports to the AER annually in our Pricing Proposal on the recovery of TUOS from our network tariffs, and makes adjustments to subsequent pricing periods to account for over or under recovery of those charges in accordance with the Distribution Determination 2010-15. Ergon Energy proposes to continue this process in the upcoming regulatory control period.

With the exception of changes to transitional arrangements, our approach is consistent with current period arrangements.

Ergon Energy notes that a transitional definition of designated pricing proposal charges applied to Ergon Energy in the regulatory control period 2010-15.[51] 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.[52]

Consistent with the AER's position in the Framework and Approach Paper, Ergon Energy has included the charges levied on Ergon Energy for the use of the 220kV network that supplies the Cloncurry township in the operating expenditure forecasts for Standard Control Services. We have included these costs as a bottom up adjustment to the base year operating expenditure (see Appendix A for more detail).

We have also included the charges levied by Powerlink for entry and exit services at the three non-prescribed connection points in the operating expenditure forecasts for Standard Control Services for 2015-16 and 2016-17. Ergon Energy understands that Powerlink is considering applying to the AER to have these connection services classified as prescribed services for its next regulatory control period, commencing on 1 July 2017. Subject to approval by the AER, the costs will therefore be reflected in the TUOS charges from 2017-18 onwards.

4.3.6 Jurisdictional schemes

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[53] will apply as a jurisdictional scheme in the next regulatory control period.

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.[54]

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[50] *04.01.01 – Designated Pricing Proposal Charges*
[51] NER, clause 11.39.6.
[52] There will only be three non-prescribed connection points in the next regulatory control period.
[53] Pursuant to section 44A of the *Electricity Act 1994 (Qld)*.
[54] NER, clause 6.18.7A(b).

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
- 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 current regulatory control period, 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 next regulatory control period, Ergon Energy proposes that these costs be recovered as jurisdictional scheme amounts.

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

$m (real 2014-15)	2015-16	2016-17	2017-18	2018-19	2019-20
Forecast feed-in tariff payments	110.4	106.8	104.9	102.1	99.2
Proposed recovery of jurisdictional scheme amounts	0.0	0.0	128.8	124.6	122.4

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 – Jurisdictional schemes*.

Delaying the recovery of the jurisdictional scheme amounts for the Solar Bonus Scheme means that the actual amounts paid will be known when the amount is included in the annual revenue submitted in the Pricing Proposal. This means that there will be no need for the jurisdictional scheme amounts to be estimated in advance, and no need for an adjustment mechanism to account for differences between forecast and actual payments.

4.4 Proposed pass through events

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 next regulatory control period:

- natural disaster event
- insurance cap event
- insurance event
- retail separation event
- isolated networks separation 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 – Nominated cost pass through events*.

4.5 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 identified the following project for consideration as a contingent project:

- Cairns Northern Beach Supply Reinforcement

Our supporting document *07.09.16 – Proposed Contingent Projects* sets out the assessment approach undertaken by Ergon Energy to reach this conclusion.

We have also put forward, for consideration, a general contingent project to cover large customer connections that are unknown to Ergon Energy at this time, which will result in a material amount of shared network augmentation during the next regulatory control period.

4.6 Indicative prices

The following tables set out indicative prices for selected Standard Asset Customer (SAC)[55] tariffs for each year of the next regulatory control period, as required under clause 6.8.2(c)(4) of the NER. These indicative prices are expressed in nominal terms.

Our response to the Regulatory Information Notice provides indicative prices for our larger customers.[56]

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 ($/day)	1.52	1.52	1.45	1.34	1.33	1.32
Energy Block 1 ($/kWh)	0.00	0.00	0.00	0.00	0.00	0.00
Energy Block 2 ($/kWh)	0.1531	0.1420	0.1358	0.1255	0.1241	0.1234
Energy Block 3 ($/kWh)	0.1631	0.1799	0.1720	0.1590	0.1573	0.1563

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

TOU Residential (ERTOU)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	1.52	1.52	1.45	1.34	1.33	1.32
Energy Peak ($/kWh)	0.5519	0.5519	0.5277	0.4879	0.4825	0.4795
Energy Shoulder ($/kWh)	0.2666	0.2666	0.2549	0.2357	0.2331	0.2317
Energy Off Peak ($/kWh)	0.0957	0.0890	0.0851	0.0787	0.0778	0.0774

[55] 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 Standard Asset Customers 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.

[56] Refer to templates 7.6 and 7.7.

Table 17: 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 ($/day)	1.52	1.52	1.45	1.34	1.33	1.32
Energy Block 1 ($/kWh)	0.00	0.00	0.00	0.00	0.00	0.00
Energy Block 2 ($/kWh)	0.1538	0.1530	0.1463	0.1352	0.1338	0.1329
Energy Block 3 ($/kWh)	0.1638	0.1841	0.1761	0.1628	0.1610	0.1600

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

TOU Business (EBTOU)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	1.52	1.52	1.45	1.34	1.33	1.32
Energy Peak ($/kWh)	0.4140	0.4140	0.3958	0.3659	0.3619	0.3596
Energy Shoulder ($/kWh)	0.3066	0.3066	0.2932	0.2710	0.2681	0.2664
Energy Off Peak ($/kWh)	0.1236	0.1327	0.1268	0.1173	0.1160	0.1153

Table 19: Indicative prices for SAC Large – Demand High Voltage – East, 2014-20

Demand High Voltage (EDHT)	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20
Fixed ($/day)	341.82	328.39	328.04	304.45	303.26	302.02
Demand kW ($/kW/month)	20.97	18.00	0.00	0.00	0.00	0.00
Demand kVA ($/kVA/month)	0.00	0.00	15.30	14.20	14.15	14.09
Energy ($/kWh)	0.0055	0.0060	0.0060	0.0056	0.0055	0.0055
Excess kVAr ($/kVAr/month)	0.00	0.00	0.00	4.00	4.00	4.00

Table 20: 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 ($/day)	419.28	376.52	376.11	349.07	347.71	346.29
Demand kW ($/kW/month)	28.78	25.50	0.00	0.00	0.00	0.00
Demand kVA ($/kVA/month)	0.00	0.00	21.68	20.12	20.04	19.96
Energy ($/kWh)	0.0055	0.0060	0.0060	0.0056	0.0055	0.0055
Excess kVAr ($/kVAr/month)	0.00	0.00	0.00	4.00	4.00	4.00

Table 21: 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 ($/day)	140.45	125.67	125.53	116.51	116.05	115.58
Demand kW ($/kW/month)	30.08	27.80	0.00	0.00	0.00	0.00
Demand kVA ($/kVA/month)	0.00	0.00	23.63	21.93	21.85	21.76
Energy ($/kWh)	0.0055	0.0060	0.0060	0.0056	0.0055	0.0055
Excess kVAr ($/kVAr/month)	0.00	0.00	0.00	4.00	4.00	4.00

Table 22: 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 ($/day)	38.73	38.73	38.69	35.91	35.77	35.62
Demand kW ($/kW/month)	33.63	29.00	0.00	0.00	0.00	0.00
Demand kVA ($/kVA/month)	0.00	0.00	24.65	22.88	22.79	22.70
Energy ($/kWh)	0.0055	0.0060	0.0060	0.0056	0.0055	0.0055
Excess kVAr ($/kVAr/month)	0.00	0.00	0.00	4.00	4.00	4.00

4.7 Supporting documentation

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

Name	Ref	File name
Demonstration of Compliance with Control Mechanisms	04.01.00	Compliance with control mechanisms
Designated pricing proposal charges	04.01.01	Designated pricing proposal charges
Jurisdictional schemes	04.01.02	Jurisdictional schemes
Nominated cost pass through events	04.01.03	Nominated pass through events
Proposed Contingent Projects	07.09.16	Contingent projects
Regulatory Information Notice	N/A	Our response to the AER's RIN is contained in a number of files attached to this proposal