



FINAL DECISION
Ergon Energy determination
2015–16 to 2019–20

Attachment 12 – Demand
management incentive scheme

October 2015

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Note

This attachment forms part of the AER's final decision on Ergon Energy's 2015–20 distribution determination. It should be read with all other parts of the final decision.

The final decision includes the following documents:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Value of imputation credits

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 7 – Operating expenditure

Attachment 8 – Corporate income tax

Attachment 9 – Efficiency benefit sharing scheme

Attachment 10 – Capital expenditure sharing scheme

Attachment 11 – Service target performance incentive scheme

Attachment 12 – Demand management incentive scheme

Attachment 13 – Classification of services

Attachment 14 – Control mechanism

Attachment 15 – Pass through events

Attachment 16 – Alternative control services

Attachment 17 – Negotiated services framework and criteria

Attachment 18 – Connection policy

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Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP	Consumer Challenge Panel
CESS	capital expenditure sharing scheme
CPI	consumer price index
DRP	debt risk premium
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ERP	equity risk premium
Expenditure Assessment Guideline	Expenditure Forecast Assessment Guideline for electricity distribution
F&A	framework and approach
MRP	market risk premium
NEL	national electricity law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSP	network service provider
opex	operating expenditure
PPI	partial performance indicators

Shortened form	Extended form
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
repex	replacement expenditure
RFM	roll forward model
RIN	regulatory information notice
RPP	revenue and pricing principles
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SLCAPM	Sharpe-Lintner capital asset pricing model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital

12 Demand management incentive scheme

The National Electricity Rules (NER) require us to develop and implement mechanisms to incentivise distributors to consider efficient alternatives to building more network.¹ To meet this requirement, and motivated by the need to improve distributors' capability in the demand management area, we implemented a demand management incentive scheme (DMIS) for Ergon Energy' distribution determination for the 2010–15 regulatory control period.²

The current DMIS for Queensland distributors includes the demand management innovation allowance (DMIA).³

The DMIA is a capped allowance for distributors to investigate and conduct broad-based and/or peak demand management projects. It contains two parts:

- Part A provides for an innovation allowance to be incorporated into each distributor's revenue allowance for opex each year of the regulatory control period. Distributors prepare annual reports on their expenditure under the DMIA⁴ in the previous year, which we then assess against specific criteria.⁵
- Part B compensates distributors for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A. During the 2010–15 regulatory control period, Queensland distributors were subject to a revenue cap form of control. As the revenue cap will continue in 2015–20 regulatory control period, Part B remains not relevant to Queensland distributors.

Currently, only Part A of the scheme applies to Queensland distributors.

Under the scheme, we return any underspend against the allowance to customers. Also, once we know the approved DMIA expenditure for each year of the current period, we compensate distributors for approved foregone revenue. We implement this as an adjustment to each distributor's innovation allowance in the following regulatory control period.

¹ NER, cl. 6.6.3(a).

² The rules have since changed the name to 'Demand Management and Embedded Generation Connection Incentive Scheme' (DMEGCIS) to explicitly cover innovation with respect to the connection of embedded generation. Our current and proposed DMIS includes embedded generation. We consider embedded generation to be one means of demand management, as it typically reduces demand for power drawn from a distribution network.

³ AER, *Demand management incentive scheme – Energex, Ergon Energy and ETSA Utilities: 2010–15*, 17 October 2008 (AER, *DMIA for QLD and SA distributors*, October 2008).

⁴ The DMIA excludes the costs of demand management initiatives approved in our determination for the 2011–15 regulatory control period.

⁵ AER, *DMIA for QLD and SA distributors*, October 2008, pp. 5–6.

12.1 Final decision

We have determined to continue Part A of the DMIS for Ergon Energy in the 2015–20 regulatory control period (that is, the DMIA component). This is consistent with our proposed approach in our preliminary decision.⁶

The current innovation allowance amount of \$1 million (\$2014–15) per annum will continue in the 2015–20 regulatory control period.

12.2 Ergon Energy's revised proposal

Ergon Energy supported the proposed approach set out in the preliminary decision to continue applying Part A (the DMIA) of the DMIS at the same scale it is currently applied.⁷

12.3 AER's assessment approach

The rules require us to have regard to several factors in developing and implementing a DMIS for Ergon Energy.⁸ These are:

- Benefits to consumers
 - the need to ensure that benefits to electricity consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme
 - the willingness of customers or end users to pay for increases in costs resulting from implementing DMIS.
- Balanced incentives
 - the effect of a particular control mechanism (i.e. price as distinct from revenue regulation) on a distributor's incentives to adopt or implement efficient non-network alternatives
 - the effect of classification of services on a distributor's incentive to adopt or implement efficient embedded generator connections
 - the extent the distributor is able to offer efficient pricing structures
 - the possible interactions between DMIS and other incentive schemes.

We had regard to these factors in considering the proposed approach to the DMIS for Ergon Energy as set out in our final F&A⁹ and preliminary decision¹⁰ and we have again taken these factors into account in making our final decision.

⁶ AER, *Preliminary decision Ergon Energy distribution determination 2015-16 to 2019-20, Attachment 12 – Demand management incentive scheme*, April 2015, p. 7.

⁷ Ergon Energy, *Revised Regulatory Proposal*, 3 July 2015, p. 32 (.).

⁸ NER, cl 6.6.3(b).

⁹ AER, *Framework and Approach*, April 2014, p. 126. (AER, *Framework and Approach*, April 2014).

12.4 Reasons for final decision

We have determined the current innovation allowance amount of \$1 million (\$2014–15) per annum (or \$5 million over the period) will continue in the 2015–20 regulatory control period. Ergon Energy supported this approach in their revised proposal.¹¹

We received a submission from the Total Environment Centre (TEC) which stated they want us to do more to reflect the importance of demand management within the current framework and provide distribution businesses with guidance on how they could design and present effective demand management strategies. TEC believe the current DMIA funds are not enough to be considered a serious alternative to long term investment in load management schemes whilst also questioning the reliance on new mechanisms such as the CESS, RIT-D and tariff reform to incentivise demand management.¹²

We acknowledge the need to reform the existing demand management incentive arrangements and the importance of demand management in deferring the need for network augmentation by alleviating network utilisation during peak usage periods. However, quite separately to incentive or innovation allowances, the revenue cap form of control removes any disincentive for distributors to reduce the quantity of electricity sold by pursuing demand management initiatives. More robust obligations to consider non-network alternatives under RIT-D requirements also provide distributors with opportunities to improve and expand their demand management programs.

We recognise the importance of appropriate demand management incentives in order to defer network augmentation. In response to submissions, we do not consider it appropriate to change the process for approval of projects in parallel to developing a new DMIS and DMIA. The AEMC's final rule determination¹³ requires us to develop a demand management incentive scheme and allowance by 1 December 2016. In response to the TEC, we consider that an additional guideline is not required. This is consistent with the AEMC's final rule determination. We will develop the scheme in accordance with the distribution consultation procedures and the scheme and allowance will be supported by a decision document and explanatory material. Individual distributors will also be consulted on the application of the scheme through the F&A process.

¹⁰ AER, *Preliminary decision Ergon Energy distribution determination, Attachment 12 – Demand management incentive scheme*, April 2015, pp. 7–8.

¹¹ Ergon Energy, *Revised Regulatory Proposal*, 3 July 2015, p. 32 (.

¹² TEC, *Submission to the AER on the Preliminary Decisions on the QLD DBs' Regulatory Proposals 2015-20*, July 2015, pp. 2–9.

¹³ AEMC, *Rule Determination, National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015*, 20 August 2015: <http://www.aemc.gov.au/getattachment/f866b41b-753b-471c-91cf-4f558ca130b2/Final-rule-determination.aspx>

For these reasons, we are not making any changes to the DMIS and we have adopted the position proposed in our preliminary decision and approved DMIA allowances consistent with their current scale.

Ergon Energy proposed a small number of demand management costs as part of its total forecast operating expenditure building block. Our decision on Ergon Energy's demand management related operating expenditure building block can be found in attachment 7.