AEMC

RULE CHANGE

Australian Energy Market Commission

CONSULTATION PAPER

National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015

Rule Proponents

COAG Energy Council
Total Environment Centre

19 February 2015

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About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Contents

1 Introduction

This consultation paper addresses two rule change requests submitted to the Australian Energy Market Commission (AEMC) in relation to the incentives for distribution businesses to pursue efficient demand management and embedded generation connections. These were submitted in response to recommendations made by the AEMC in its Power of Choice review, completed in November 2012.

On 22 November 2013, the Total Environment Centre (TEC) submitted a rule change request proposing amendments to the demand management and embedded generation connection incentive scheme (DMEGCIS).[1] The TEC's rule change request seeks to make it easier for the Australian Energy Regulator (AER) to design and implement a "reformed DMEGCIS" that will help to incentivise distribution businesses to undertake demand management projects as an alternative to building new network infrastructure. It is intended to complement existing obligations on these businesses to examine non-network alternatives to new network investment as part of the regulatory investment test for distribution (RIT-D) process.

On 17 December 2013, the Council of Australian Governments (COAG) Energy Council[2] submitted a rule change request which also proposed to amend the DMEGCIS arrangements.[3] The COAG Energy Council's rule change request seeks to achieve an appropriate return to distribution businesses to incentivise efficient demand management projects, as well as to improve clarity and certainty around how the scheme will be developed and implemented. This is intended to strengthen the incentives for distribution businesses to undertake demand management projects that deliver a net benefit to consumers.

As the COAG Energy Council rule change request covers similar issues to those presented in the TEC rule change request, the Commission has decided to consolidate the two rule change requests. This will enable a single consultation and decision process.

This consultation paper has been prepared to facilitate public consultation on the two rule change requests, and to seek stakeholder submissions.

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1 The TEC developed its rule change request following the conclusion of the Power of Choice review. It stated it did so for two reasons. First, having regard to the length of the AEMC's rule change process, it considered it important for a reformed demand management incentive scheme to be in place for the implementation of the New South Wales/Australian Capital Territory and Queensland distribution determinations on 1 July 2015. Second, it considers its rule change request improves on the proposed amendments to the DMEGCIS recommended by the AEMC in its Power of Choice review, by providing some additional clarity and scope. See: TEC, rule change request, p.3.

2 The COAG Energy Council was formerly called the Standing Council on Energy and Resources.

3 The COAG Energy Council rule change request was developed based on recommendations contained in the AEMC's Power of Choice review. It is part of the broad energy reform package to support investment and market outcomes in the long term interests of consumers as agreed by COAG and SCER in December 2012. See: COAG Energy Council, rule change request, cover letter.

The consultation paper:

- sets out the background to the rule change requests;
- identifies the issues that the rule change requests are seeking to address;
- summarises the solutions proposed in the rule change requests;
- sets out a proposed assessment framework to be used by the Commission in assessing the rule change requests;
- identifies a number of questions and issues to facilitate public consultation on the rule change requests; and
- outlines the process for making submissions.

Submissions to this consultation paper are due by no later than 19 March 2015.

2 Background

2.1 Distribution businesses and demand side participation

Distribution businesses can play an important role in engaging the demand side of the market. They do this through directly undertaking demand management projects as an efficient alternative to network capital expenditure. They also support the delivery of demand management by other parties, such as aggregators, through efficient and flexible network tariffs and publishing planning information.

The economic regulatory framework for distribution businesses is primarily set out in Chapters 5, 5A and 6 of the National Electricity Rules (NER). It uses incentives and obligations to encourage these businesses to generate outcomes that consumers need, want and are willing to pay for, and to do so efficiently and in line with jurisdictional reliability standards. With respect to demand management, the objective of the regulatory framework is to achieve an outcome where distribution businesses pursue and develop demand management projects when these are at least as efficient as network capital investment. The regulatory framework will be consistent with this objective if it leads to an outcome where consumers' demand for electricity is met by the lowest cost combination of demand and supply side options.

The current incentive frameworks and obligations in the NER are designed to encourage distribution businesses to make efficient investment and expenditure decisions. They do so by better aligning the incentives (or savings) between capital and operating expenditure, and between network and non-network investment.

Broadly, the relevant arrangements relate to two areas of the regulatory framework for distribution businesses:

- **Planning and investment framework:** Included in Chapter 5 of the NER, the distribution network connection, planning and expansion framework is designed to encourage distribution businesses and other network users to make efficient planning and investment decisions. It does so by creating incentives for, and a framework within which, distribution businesses can explore non-network options as alternatives to network capital investment.

  The key components of this framework include the distribution annual planning report (DAPR), demand side engagement strategy (DSES) and the RIT-D and associated RIT-D project assessment process.

- **Incentive regulation framework:** Set out in Chapter 6 of the NER, the incentive regulation framework is designed to encourage distribution businesses to spend efficiently and to share the benefits of efficiency gains with consumers. Specifically, it is designed to encourage distribution businesses to make efficient decisions on when and what type of expenditure to incur in order to meet their network reliability, safety, security and quality requirements.

The key incentive schemes include the efficiency benefit sharing scheme (EBSS), and the capital expenditure sharing scheme (CESS) and associated ex-post review mechanism for capital expenditure.

The regulatory framework also includes arrangements which allow the AER to develop and apply a demand management and embedded generation connection incentive scheme. The DMEGCIS arrangements recognise that there are a number of risks and issues associated with demand management which mean that the planning and investment framework, and the incentive regulation structure, may not be sufficient by themselves to remove any bias towards network capital investment over demand side responses. Those issues include:

- Demand management is relatively new.
- Demand management on distribution networks may have spill over benefits for other parts of the electricity supply chain which distribution businesses may not consider when making investment decisions.
- Under certain control mechanisms (that is, price cap)[4], distribution businesses may have reduced incentives to use demand management because reductions in demand result in reductions in the maximum regulated revenue that the business is permitted to earn.

The intent of the current DMEGCIS arrangements is therefore to provide distribution businesses with an appropriate financial reward for pursuing demand management projects where these provide an efficient alternative to network capital expenditure. The current DMEGCIS is explained further in the next section.

2.2 Current DMEGCIS

2.2.1 NER requirements

Chapter 6 of the NER provides the AER with the discretion to develop and publish a DMEGCIS. The purpose of the scheme, as stated in the NER, is to:[5]

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4 The NER allows the AER to determine the control mechanism to be applied to distribution businesses from a range of options that includes a revenue cap, a price cap, a weighted average price cap (WAPC) or some other alternative, having regard to criteria set out in the NER. Revenue caps and WAPC are the most common forms of control mechanism used by the AER. A revenue cap works by allowing network prices to change annually over the current regulatory control period in order to recover annual revenues determined for a distribution business at the start of the regulatory control period. A business under a revenue cap is guaranteed its revenue in the current regulatory control period. A WAPC works by constraining changes in average annual network prices determined at the start of the current regulatory control period. Revenues of a business under a WAPC can therefore fluctuate from year to year within its current regulatory control period. See: AEMC 2013, Consideration of Differences in Actual Compared to Forecast Demand in Network Regulation, Advice to SCER, 26 April 2013, Sydney, pp.9-10.

5 NER clause 6.6.3(a).

> "…provide incentives for *Distribution Network Service Providers* to implement efficient non-*network* alternatives, or to manage the expected demand for *standard control services* in some other way, or to efficiently connect *Embedded Generators*."

The NER requires that, in developing and implementing the scheme, the AER must have regard to a number of factors, including:[6]

- 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 for distribution businesses;
- the effect of a particular control mechanism, (that is price – as distinct from revenue – regulation) on a distribution business's incentives to adopt or implement efficient non-network alternatives;
- the extent the distribution business is able to offer efficient pricing structures;
- the possible interaction between a DMEGCIS and other schemes under Chapter 6 of the NER;[7]
- the willingness of the customer or end user to pay for increases in costs resulting from implementation of the scheme; and
- the effect of classification of distribution services as determined in accordance with clause 6.2.1 on a distribution business's incentive to adopt or implement efficient embedded generation connections.

2.2.2 Design of the current DMEGCIS

The AER has developed a DMEGCIS and applied it as part of the distribution determinations of all distribution businesses in the national electricity market (NEM). Because the AER decided to continue similar schemes established by jurisdictional regulators prior to the introduction of the NER for its first round of distribution determinations under the NER, different schemes apply in different jurisdictions. However, the AER's schemes are generally divided into two parts:

- Part A: demand management innovation allowance (DMIA); and
- Part B: foregone revenue component.

Part A is an innovation allowance that provides funding to distribution businesses to trial innovative demand management and embedded generation connections schemes. It is provided to distribution businesses in the form of a fixed amount of additional

6 NER clause 6.6.3(b).

7 The other incentive schemes in Chapter 6 of the NER are: the EBSS under clause 6.5.8, the CESS under clause 6.5.8A, the service target performance incentive scheme (STPIS) under clause 6.6.2 and the small scale incentive scheme (SSIS) under clause 6.6.4.

revenue at the commencement of each year of the current regulatory control period. In the second year of the next regulatory control period, when results for the five years of the current regulatory control period are known, a single adjustment is made to return the amount of any underspends or unapproved DMIA amounts to customers.

The AER is required to annually assess any claims for the DMIA against criteria it has developed and set out in the DMEGCIS. The criteria are descriptive and allow for a wide range of projects to be approved.

Part B is a payment to distribution businesses designed to address the impacts that certain forms of control (such as the price cap) may have on a distribution business's incentives to undertake efficient demand management. It allows the distribution businesses to recover foregone revenue in a regulatory control period resulting from a reduction in the quantity of energy sold directly attributable to demand management projects or programs approved under Part A of the scheme.

A key objective of the DMEGCIS is to assist in enhancing industry knowledge of practical demand management projects and programs through the annual publication of demand management incentive scheme (DMIS) reports from distribution businesses.[8] Distribution businesses are required to submit an annual report to the AER on their DMIS expenditure at the end of each year. The information provided in a distribution business's annual DMIS report is used in the AER's assessment of a distribution business's compliance with the DMIA criteria and entitlement to recover expenditure under the DMIA.

The DMEGCIS is not intended to be the sole, or even the primary, source of recovery of demand management expenditure by a distribution business. Rather, its purpose is to complement the incentive regulation structure by supplementing a distribution business's approved capital expenditure (capex) and operating expenditure (opex) to facilitate investigation and implementation of demand management strategies. It also aims to correct any disincentives that might discourage distribution businesses from undertaking demand management.

Appendix A provides some additional information on the current application of the two components of the current DMEGCIS.

2.3 Power of Choice recommendations

The AEMC completed the Power of Choice review in November 2012 and recommended to the COAG Energy Council (known at the time as the Standing Council of Energy and Resources (SCER)) a package of reforms designed to encourage consumers to make more efficient consumption choices that trade off the value of consuming electricity against the cost of supplying that electricity.[9]

8 AER, 2011–12 and 2012 DMIA assessment, Decision, July 2013.

9 The overall objective of the Power of Choice review was to ensure that the community's demand for electricity services is met by the lowest cost combination of demand and supply side options. This objective is best met when consumers are using electricity at the times when the value to them

Amongst other things, the AEMC recommended to SCER a package of rule changes designed to address issues within the existing regulatory framework for distribution businesses to provide them with better incentives to use demand management to reduce overall capital and operating costs.

In relation to distribution networks and demand management, the review examined whether the regulatory arrangements were providing the right incentives for distribution businesses to implement demand management projects as an efficient alternative to network capital investment. This work was carried out in response to a concern from some stakeholders that distribution businesses were not reacting to the current incentive arrangements in respect of pursuing efficient demand side options, as intended.

The review identified a number of reasons why this may be the case, including:

- issues with the existing regulatory arrangements (from the way financial incentives were applied to how network tariffs were set); and
- individual business preferences, practices and experiences.

The Power of Choice review made the following recommendations in relation to the incentives for distribution businesses to undertake demand management projects that provide net benefits for consumers:

- reforming the application of DMEGCIS to provide an appropriate return for demand management projects which deliver a net cost saving to consumers;
- adopting a two part approach to address the issue of business profits being dependent on actual volumes: first, improve the pricing principles to guide network tariff structures; and second, include an allowance for foregone profit under the revised DMIS; and
- making minor amendments to the NER to provide clarity that the AER can have regard to non-network market benefits when assessing the efficiency of expenditure and flexibility in the annual tariff process to manage potential extra volatility of demand management costs.

These recommendations were grouped into two recommended rule changes: the first related to distribution network pricing arrangements; and the second to the DMEGCIS arrangements.

In respect of the former, on 27 November 2014, the AEMC published a final rule determination and final rule. The new distribution network pricing arrangements rule requires distribution businesses to set prices that reflect the efficient cost of providing network services to individual consumers. This will allow consumers to make more informed decisions about their use of electricity. Network prices based on the new

is greater than the cost of supplying that electricity (that is, the cost of generation and poles and wires). See: AEMC 2012, Power of choice review - giving consumers options in the way they use electricity, Final Report, 30 November 2012, Sydney.

pricing objective and pricing principles introduced by the rule will be gradually phased in from 2017.

The recommendations made in relation to the DMEGCIS arrangements are the subject of these rule change requests.

At the time of the Power of Choice review, a number of other rule changes were also being progressed by the Commission which related to the existing regulatory arrangements for distribution businesses:

- The *Economic regulation of network service providers* rule change request (network regulation rule change request) addressed, among other things, how the current arrangements provide incentives for efficient capital and operating expenditure and determine the allowed rate of return.[10]
- The *Distribution network planning and expansion framework* rule change request considered issues associated with how distribution businesses include demand management alternatives in their planning and project assessment process.[11]
- The *Connecting embedded generators* rule change request provided a clearer, more transparent connection process with defined timeframes and information requirements to reduce barriers to the connection of embedded generators to distribution networks.[12]

10 AEMC 2012, Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Final Position Paper, 29 November 2012, Sydney.

11 AEMC 2012, Distribution Network Planning and Expansion Framework, Rule Determination, 11 October 2012, Sydney.

12 AEMC 2014, Connecting Embedded Generators, Rule Determination, 17 April 2014, Sydney.

3 Issues the rule change requests are seeking to address

3.1 Gaps in the current regulatory framework for distribution businesses

Prior to the Power of Choice review, investment in network infrastructure had been growing significantly. During the same period, distribution businesses had been, to varying degrees, trialling and implementing new flexible pricing and incentive based demand side initiatives. However, the scope of these initiatives was small, and the potential for demand management to provide a credible, efficient alternative to network investment remained largely untapped.[13]

Stakeholders, including distribution businesses, generally considered that the existing regulatory arrangements may have been discouraging distribution businesses from pursuing efficient demand management projects. The main reason for this was the insufficient financial reward available to distribution businesses to motivate them to undertake demand management. Stakeholders considered that this had led to a preference towards network capital investment (which consumers pay for over the long term) and under development of the potential of the demand side.[14]

As noted in Chapter 2, the regulatory framework for distribution businesses includes a number of mechanisms and measures designed to encourage efficient expenditure decisions and remove potential regulatory biases towards network capital investment. This includes the arrangements for a DMEGCIS.

However, to date this scheme has been applied in a limited manner and operates as a pass through of costs incurred in undertaking approved demand management activities plus an innovation allowance. For each year of their current regulatory control periods, the distribution businesses have been allocated an innovation allowance of between $100,000 and $1 million by the AER.[15] Further, for the 2011-2012 and 2012 regulatory years, no distribution business sought forgone revenue as part of their DMIA expenditure.[16]

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13 AEMC 2012, Power of choice review - giving consumers options in the way they use electricity, Final Report, 30 November 2012, Sydney, Chapter 1.

14 ibid, pp.199-200.

15 The use of innovation allowances by regulators to facilitate change is not new. As part of the new regulatory framework in Great Britain, Ofgem has introduced a number of mechanisms to incentivise network businesses to undertake innovative projects as part of their business as usual approach to network planning and investment. Further information on Ofgem's innovation framework may be found in Appendix B of this consultation paper.

16 Non-Victorian distribution businesses' regulatory years align with financial years, whereas Victorian distribution businesses regulatory years align with calendar years.

3.2 Current DMEGCIS not operating as intended

The proponents of the two rule change requests reiterated the reasons identified in the Power of Choice review for why the DMEGCIS has not been effective in encouraging an efficient level of demand management in the market:[17]

- The current scheme focuses on cost recovery only and does not provide distribution businesses with an opportunity to make profits on demand management projects. In this sense, the scheme is not a true incentive scheme that allows a distribution business to earn extra rewards where it has delivered defined goals.
- The innovation allowance has been modest and potentially too limited in scope to genuinely encourage experimentation and innovation with new demand management methods.
- Any reward available to distribution businesses for undertaking demand management projects was of relatively short duration relative to the long term returns available on network investment.
- Distribution businesses have not been able to capture the benefits from demand management initiatives created at other levels of the supply chain - for example, the benefits associated with reduced generation capital and operating expenditure.
- There is uncertainty as to whether demand management related expenditure would be treated differently compared to normal capital and operating expenditure under the NER (for example, considered less prudent with respect to the expenditure objectives and criteria under NER clauses 6.5.6 and 6.5.7).

The consolidated rule change request noted there are greater uncertainties and risks associated with demand management options compared with traditional network investment and capital expenditure providing for stable returns. Distribution businesses are consequently likely to favour capital investment for addressing network limitations and demand growth.[18]

As an example, the TEC noted that current demand management is equal to less than two per cent of NEM-wide peak demand and only about one per cent of the generation capacity in the NEM.[19]

That is, the DMEGCIS does not appear to be providing sufficient incentive or certainty for distribution businesses to explore and develop efficient demand management options as an alternative to network investment.

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17 COAG Energy Council, rule change request, pp.3-4.

18 ibid.

19 TEC, rule change request, p.4.

4 Solutions put forward in the rule change requests

The COAG Energy Council and TEC rule change requests seek to address the issues raised above by amending the DMEGCIS arrangements in Chapter 6 of the NER. The objective is to assist the AER to strengthen the incentives for distribution businesses to undertake demand management projects that deliver a net benefit for consumers.

The two proposals share a number of key features as they were both developed having regard to the recommendations made by the AEMC in its Power of Choice review. The proposed amendments to Chapter 6 of the NER which are common to both rule change requests are as follows:

- Explicit separation of the current DMEGCIS into a demand management incentive scheme (DMIS) and a demand management incentive allowance (DMIA).
- Introduction of an explicit objective, and set of principles, to guide the AER in its development and application of the DMIS.[20]
- Providing scope for the AER to include two forms of reward under the DMIS:
  - a payment based on a proportion of the net market benefits (or avoided or deferred network costs) produced by a demand management project; and
  - a payment as compensation for any lost revenues or profits that occur as a result of reduced demand from implementing a demand management option, where appropriate.

While similar in their overarching objectives, the COAG Energy Council and TEC rule change requests differ in their details:

- In respect of the payment to distribution businesses of a proportion of net market benefits directly attributable to demand management projects, the COAG Energy Council rule change request specifies that distribution businesses would be able to retain a maximum of 30 percent of the associated non-network related market benefits, while the TEC rule change request specifies a maximum of 50 percent.
- In respect of the payment to distribution businesses as compensation for a reduction in demand resulting from demand management projects, the COAG Energy Council rule change request proposes that the allowance be for forgone profit, while the TEC rule change request proposes an allowance for foregone revenue.
- The COAG Energy Council rule change request would clarify that only non tariff based demand management projects would be included within the scope of the

20 The proposed wording of the objective and principles differ slightly between the proponents.

incentive scheme,[21] the TEC rule change request proposes to include both tariff and non tariff based projects within the scope of the scheme.

- The COAG Energy Council rule change request would require the AER to develop guidelines for how incentive payments would be determined, including guidance on the calculation of benefits available for reward and the calculation of lost profits to be compensated.

The table below sets out the common features and key differences between the current rules and the arrangements proposed by the COAG Energy Council and TEC in the rule change requests.

For details of all the amendments proposed to Chapter 6 of the NER, refer to the draft rule included with the TEC's rule change request[22] and the draft specifications included in the COAG Energy Council rule change request.[23]

Table 4.1 Comparison of key components of the current and proposed rules

Key feature	Current rules[24]	COAG Energy Council proposal	TEC proposal
Demand Management Incentive Scheme			
Arrangements for incentive scheme separate from innovation allowance	No	Yes	Yes
Scheme must be applied consistent with an explicit objective	No (but implicit objective)	Yes	Yes
Scheme must be applied consistent with a set of principles	No	Yes	Yes
The scheme must be published within nine months of any rule being made	N/A	Yes	Yes
The scheme must be developed/amended in accordance with the distribution consultation procedures set out in the rules	Yes	Yes	Yes
The scheme must be developed consistent with certain factors	Yes	Yes	Yes

21 While both tariff and non tariff based demand management projects would be eligible for funding under the innovation allowance, only non tariff based projects would be included within the scope of the incentive scheme (that is, eligible for the foregone revenue compensation payment).

22 TEC, rule change request, Appendix 2.

23 COAG Energy Council, rule change request, Attachment A.

24 In many instances below, the key feature described is implicit in the current rules, that is, within the scope of the objective and factors set out under NER clause 6.6.3.

Key feature	Current rules[24]	COAG Energy Council proposal	TEC proposal
Allowance for a payment of a proportion of net market benefits attributable to a demand management project	No	Yes	Yes
AER has discretion to determine the percentage of non-network market benefits retained by a distribution business	No	Yes	Yes
Specification in the rules of the maximum percent of non-network market benefits to be retained by a distribution business	No	Yes (30 percent)	Yes (50 percent)
Allowance for payment of lost revenue resulting from implementing a demand management project	No (but AER included in current scheme)	Yes (foregone profit)	Yes (foregone revenue)
AER must publish guidelines to support application of the incentive scheme	No	Yes	No
AER must publish an annual assessment report on the effectiveness of the scheme	No (but AER does as part of current scheme)	Yes	No
Tariff and non tariff based demand management projects included within the scope of DMIS	No (but both included by AER in current scheme)	Yes	Yes
Demand Management Innovation Allowance			
AER must consider the uniqueness of a project having regard to domestic and international activities	No	Yes	No
AER should consider the ability of a distribution business to seek other funding for projects	No (but included by AER in current scheme criteria)	Yes	No
Distribution businesses must provide relevant information from funded pilots and trials to the AER for publication	No (but included by AER in current scheme criteria)	Yes	Yes
AER has discretion to develop the design of the innovation allowance, including the amount for each distribution business	No (but AER does as part of current scheme)	Yes	Yes

Key feature	Current rules[24]	COAG Energy Council proposal	TEC proposal
Approved projects must be published by distribution businesses in their DAPRs	No	Yes	Yes
AER must publish guidelines to support application of the innovation allowance	No	Yes	No
Tariff and non tariff based demand management projects included within the scope of DMIA	No (non tariff only)	No (non tariff only)	Yes
Other			
Prudency of demand management expenditure assessed in same way as capex and opex by the AER	No	Yes	Yes

In its rule change request, the COAG Energy Council considered its proposed amendments to Chapter 6 of the NER would promote the national electricity objective (NEO) by strengthening the incentives for distribution businesses to undertake efficient demand management projects that reduce the overall costs of supplying electricity to consumers.[25]

In its rule change request, the TEC considered its proposed rule would contribute to the achievement of the NEO by promoting more efficient investment in distribution networks, assist consumers to save energy through increased demand management and contribute to lower retail electricity bills for consumers.[26]

25 COAG Energy Council, rule change request, p.10.

26 TEC, rule change request, p.9.

5 Assessment Framework

The Commission's assessment of this rule change request must consider whether the proposed rule promotes the NEO as set out under section 7 of the National Electricity Law (NEL).

The NEO states:[27]

> "The objective of this Law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

Based on a preliminary assessment of the rule change requests, the relevant aspects of the NEO are the promotion of efficient investment in, and operation of, distribution electricity services for the long term interests of consumers with respect to price.

More specifically, investing in and operating the networks in the long term interests of consumers means that network reliability, safety, security and quality requirements are met at efficient long term cost. This outcome will be achieved if a number of conditions are met:

- **Demand is met at lowest total system cost**: Incentive-based regulation provides incentives for distribution businesses to behave in a way that lowers overall total system costs which, over time, will lead to prices and/or reliability, safety, security and quality benefits for consumers. In other words, the regulatory framework should promote efficient decision making that encourages distribution businesses to appropriately trade-off between network and non-network investment to reduce overall costs.

- **Efficient investment in and use of assets takes place**: The incentives applied through the regulatory framework are an important determinant of how efficient distribution businesses invest in and maintain their infrastructure. The regulatory framework should therefore aim to enable:

  — use of existing assets to be optimised;[28]

  — the network to be managed to meet changing demand;[29] and

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27 See s. 7 of the NEL.

28 Using the existing infrastructure to its optimal capacity means that additional investment is not taking place before the full value of the existing assets has been realised. If assets are under-utilised or replaced before the end of their useful lives, demand will not be met at efficient long term cost.

— assets to be replaced at the end of their useful life if it is necessary and efficient to do so.[30]

- **Distribution businesses are able to recover efficient costs**: The regulatory framework should only allow for an efficient level of costs to be recovered by distribution businesses, rather than allowing an automatic pass-through of all expenditure. This would promote efficient investment in distribution networks while allowing the businesses to recover the efficient costs of owning and operating their networks.

- **Efficiency and innovation are rewarded**: There should be a positive relationship between efficiency and reward, and the distribution businesses should be able to keep a share of any cost-savings made so as to incentivise continued improvements in efficiency. Equally, the businesses should bear at least a share of the costs and risks involved in innovation, so that any such costs are prudently incurred.

It is proposed that the assessment of the consolidated rule change request will analyse individually both the demand management incentive scheme and the demand management innovation allowance components of the DMEGCIS.

The proposed amendments in the consolidated rule change request will also be assessed against the relevant counterfactual arrangements which, in this case, are the existing provisions in the NER.

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29 All available options to manage changing demand are considered, including building new infrastructure, expanding existing infrastructure or managing demand in other ways.

30 Decisions are made on a holistic basis about maintenance of existing assets, investment in new assets and other options such as demand side management.

6 Issues for Consultation

This chapter identifies a number of issues for consultation that appear to be relevant to this consolidated rule change request. The issues outlined below are provided for guidance. Stakeholders are encouraged to comment on these issues as well as any other aspect of the consolidated rule change requests, or this consultation paper, including the proposed assessment framework.

6.1 Issues this rule change is seeking to address

Assessing the proposed amendments to Chapter 6 of the NER first requires clear articulation of the problem that these consolidated rule change requests are seeking to address. This is particularly important in light of the changes that have occurred in the market and in relation to the regulatory framework for distribution businesses in the time since conclusion of the Power of Choice review in late 2012.

In particular, weakening demand has contributed to a decline in the capital expenditure and revenue requirements of the distribution businesses. In addition, the range of reforms designed to encourage distribution businesses to consider demand management options as part of business as usual are now operational. These changes have implications for distribution businesses' motivations for, and methods of, pursing demand management projects as efficient alternatives to network investment.

In this context, the first step in this assessment will be to understand whether the gap in the regulatory framework that the DMEGCIS arrangements were intended to fill still exists and, if so, to what extent. This matter is explored further below.

6.1.1 Changing market conditions

In the years preceding the Power of Choice review, the capital expenditure programs of the distribution businesses had been growing significantly. This growth was driven by factors including the need to replace ageing assets, stricter jurisdictional reliability requirements and the need to respond to demand forecasts made at the time of rising peak demand.[31]

AER determinations made from 2009 to 2011 reflected these increased capital needs, with the decisions providing for increases in real investment by 46 per cent, on average, compared with the previous regulatory period. The increasing cost of using the electricity networks which resulted was the main driver of rising electricity retail prices in most jurisdictions.[32]

31 The capital expenditure programs of distribution businesses are driven by a number of factors. In order to ensure that network reliability standards continue to be met, the forecast level of peak demand is the primary driver of the need to upgrade distribution networks. In addition, the need to incorporate new customer connection requests (growth capex) and replace ageing assets (replacement capex) also drive distribution businesses investment requirements.

32 AER, State of the energy market 2014, December 2014, Chapter 2.

These pressures have eased more recently. Most significantly, the demand for electricity has weakened, driven by the following factors:

- Commercial and residential customers are more actively managing their energy use in response to price signals.
- Economic growth has been subdued and energy demand from the manufacturing sector has weakened (reflecting an ongoing decline in energy intensive industries).
- Rooftop solar PV generation continues to increase which reduces demand for electricity supplied through the grid.

Additionally, maximum demand (which typically occurs during heatwaves when air conditioning use is high) has flattened and is forecast to remain below historical peaks in most regions for at least the next 20 years.[33]

The effect of weakening demand, along with less stringent reliability obligations on the network businesses in some jurisdictions, has been a reduction in the number of planned network investments, including the deferral of projects that had already passed a regulatory investment test.[34]

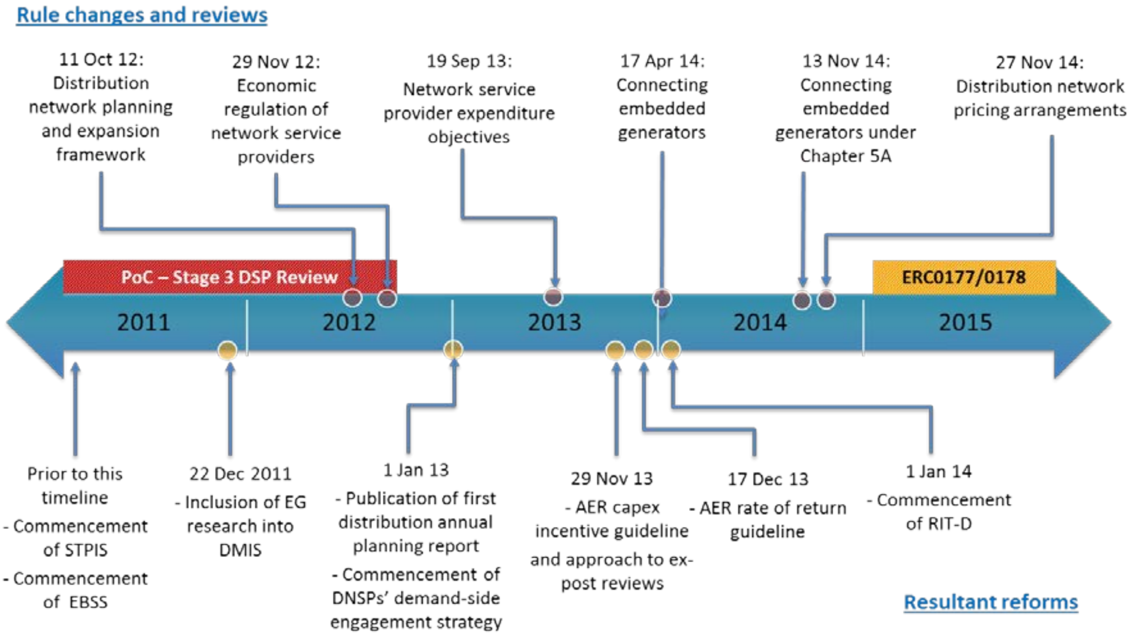
6.1.2 Changing regulatory framework

Alongside the changes in market conditions, the regulatory framework for distribution businesses has also undergone considerable change since completion of the Power of Choice review in 2012. Concerns raised in relation to distribution businesses tendency to favour network investment over non-network solutions have been mitigated, at least to some extent, by a number of reforms specifically targeted towards distribution businesses and their motivation for pursuing demand management. Figure 6.1 sets out the key reforms in place since the review.

33 ibid.

34 If forecasts of peak demand fall, distribution businesses may be able to reduce or defer the amount of investment needed in order to ensure that the required reliability standards continue to be met. The business may consequently spend less than the capex allowance. The extent to which the network business considers it is able to reduce or defer its expenditure will depend on whether it expects the lower level of demand forecast to be maintained, and its overall approach to managing the risk of failing to meet its reliability obligations (which may result in a more conservative approach being adopted in relation to reductions in expenditure). A reduction in peak demand may also mean that demand management options become feasible alternatives to network investment.

Figure 6.1 Overview of changes to the regulatory framework following Power of Choice



The distribution annual planning report (DAPR) increases transparency around distribution business planning and investment activities. Among other things, it requires the businesses to provide details on current and forecast network limitations. This allows non-network providers to take a more informed view of the potential for non-network options to provide appropriate and efficient solutions to those limitations.

In addition, the demand side engagement strategy encourages timely and meaningful engagement between network businesses and non-network providers. By obliging the businesses to articulate and publish the processes and procedures for interacting with non-network providers and assessing non-network alternatives, the DSES provides a tool so that consideration of demand side options as alternatives to network investment becomes part of business as usual.

The DAPR and DSES are complemented by the new RIT-D arrangements which have been designed to encourage distribution businesses to consider investment options in a transparent, consultative and technologically neutral manner. A key feature of these arrangements is the emphasis given to the exploration and identification of non-network alternatives. In particular, the RIT-D consultation procedures include a requirement for businesses to prepare and publish a non-network options report, prior to carrying out the RIT-D. The report helps distribution businesses to identify potential non-network options and be better informed on the costs and market benefits associated with a potential investment option. In doing so, it reduces the risk that efficient non-network options are overlooked in the project assessment stage, and thus improves the application of the RIT-D.

The AEMC has also recently amended the NER in respect of the way the distribution businesses set and structure network prices. The changes require the businesses to develop network tariffs which better reflect their cost drivers. This will allow consumers to make more informed decisions about their energy use as new technologies emerge and result in better outcomes for both individual consumers and the overall electricity system.

Importantly, it also provides a framework for the businesses to develop network tariff structures which appropriately incentivise efficient demand side responses by customers, for example, through shifting some consumption to lower cost off-peak times or by installing technologies that help reduce their peak demand.

Collectively, these incentives and obligations are changing the way in which distribution businesses engage with non-network providers, and consider and assess demand management options as efficient alternatives to network capital investment.

Issue 1 Issues this rule change is seeking to address

1. **Having regard to current and potential future market conditions, and in light of recent changes to the regulatory framework for distribution businesses, is there a gap in the current framework which may be discouraging distribution businesses from pursuing demand management projects as an efficient alternative to network investment?**

2. **If a gap does exist, where does it lie? Is it a product of the provisions in the NER or a result of the current design of the DMEGCIS applied by the AER?**

6.2 Proposed DMEGCIS

Assuming that there remains a role for a separate incentive scheme to encourage distribution businesses to consider demand management as an efficient alternative to network investment, this section considers the key changes proposed to the DMEGCIS arrangements to enable it to operate as effectively as possible, and to meet its intended objective.

The primary source of funding for demand management projects is the opex and capex allowances approved in the AER's distribution determination for a distribution business. Chapter 6 of the NER requires the AER's assessment of a distribution business's opex and capex proposals to include an examination of the extent to which a business has considered and made provision for non-network alternatives.[35]

The DMEGCIS is intended to provide additional incentives for distribution businesses to conduct demand management to those present within the broader regulatory framework. As a result, the current rules provide the AER with discretion on whether or not to establish and implement a DMEGCIS as an additional source of funding.

35 NER clauses 6.5.6(e)(10) and 6.5.7(e)(10).

Once the AER decides to establish a DMEGCIS, the existing rules are not prescriptive on how the scheme should be implemented and applied, other than to specify a number of objectives that the AER must have regard to in designing and implementing a scheme. The objectives are set out in section 2.2 of this paper.

The key component of the AER's current DMEGCIS is the demand management innovation allowance. As noted previously, this is provided to the businesses as an ex-ante allowance in the form of a fixed amount of additional revenue at the commencement of each regulatory year of the regulatory control period. In this sense, the current DMEGCIS essentially operates as a research and development fund to encourage the businesses to conduct research and investigation into innovative techniques for managing demand.

In line with the recommendations from the Power of Choice review, the consolidated rule change requests propose to retain the current innovation allowance, but to separate it from the demand management incentive scheme through the creation of separate provisions in the NER. This is intended to allow for the clear articulation of the objective of each component of the DMEGCIS. This should address concerns identified during the Power of Choice review that there had been some misperception around the application of the incentive scheme due to the incorporation of the incentive allowance.

Although the proposed wording differs slightly between the COAG Energy Council and TEC rule change requests, the objectives of the innovation allowance and incentive scheme are proposed as follows:

- The purpose of the innovation allowance would be to provide a special source of funding for distribution businesses to experiment and trial innovative approaches to demand management and the connection of embedded generators. This recognises that some approaches to demand management and the connection of embedded generators, given their current state of evolution, are highly uncertain with respect to their costs and benefits and are unlikely to be undertaken by distribution businesses in the absence of additional funding.

- The purpose of the incentive scheme would be to encourage least cost investment and operation of the network. This would be achieved by allowing distribution businesses to access a proportion of the full benefits delivered by demand management options (that is, market benefits, at other points in the supply chain).

The proposed amendments to the NER in relation to the innovation allowance and incentive scheme, and the associated issues, are discussed in the next sections.

Issue 2 Proposed DMEGCIS

1. **In making its decision on the network regulation rule change request, the AEMC considered how much prescription the NER should include.[36] In this context, we welcome the views of stakeholders on the appropriate level of prescription to include in the NER to enable the AER to develop and apply an effective DMEGCIS. In particular:**

   (a) **Having regard to the level of flexibility and discretion afforded to the AER in designing and applying other incentive schemes under Chapter 6 of the NER, is the level of flexibility and discretion currently afforded to the AER in relation to the DMEGCIS appropriate?**

   (b) **If there is benefit in providing more prescription in the NER, is the level proposed by the COAG Energy Council and the TEC in their rule change requests appropriate?**

2. **Having regard to recent changes made by the AEMC to Chapter 5 and 5A of the NER in relation to the arrangements for connecting embedded generators, are additional financial incentives for innovation in the connection of embedded generators through the DMEGCIS required?**

6.2.1 Demand management innovation allowance

The key proposals and associated issues related to the innovation allowance are discussed below.

Flexibility versus prescription

The consolidated rule change requests propose to retain the innovation allowance and, among other things, include explicit provisions in the NER to clarify that the AER has the discretion to determine the size and application of the scheme for each distribution business.[37]

In the Power of Choice review, stakeholders indicated that innovation funding for non-network alternatives was important for encouraging efficient demand management outcomes.[38] This view was supported by both the COAG Energy Council and the TEC in their rule change requests. The TEC considered that, while

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36 AEMC 2012, Economic Regulation of Network Service Providers, and Price and Revenue Regulation of Gas Services, Final Position Paper, 29 November 2012, Sydney, p.56.

37 The use of innovation allowances by regulators to facilitate change is not new. A network innovation allowance is used in the UK to fund certain research, development, and demonstration projects that shareholders may be unwilling to fund. Further information on Ofgem's innovation framework may be found in Appendix B.

38 AEMC 2012, Power of choice review - giving consumers options in the way they use electricity, Final Report, 30 November 2012, Sydney, p.212.

currently underutilised by distribution businesses, the innovation allowance provides a valuable source of income for innovative demand management projects that may be otherwise hard to justify on economic grounds alone.[39] Similarly, the COAG Energy Council was of the view that facilitating the testing and learning of new approaches and techniques to demand management would deliver benefits to consumers by reducing network and generation related expenditures in the future.[40]

However, there was also a view at the time of the Power of Choice review that the existing innovation allowance was not effective in overcoming the barriers to innovation for distribution businesses. In particular, there was a concern that the amount of money available from the AER under the allowance was insufficient to prove beneficial for increasing demand side participation.[41] This view was also supported by the COAG Energy Council and the TEC in their rule change requests. Both proponents noted that the innovation allowance had been modest and potentially too limited in scope to genuinely encourage experimentations and innovation with new demand management methods.[42]

As noted above, the existing rules are not prescriptive on how the DMEGCIS should be implemented, other than to specify a number of factors that the AER must have regard to when designing and applying the scheme.[43] Therefore, by effectively staying silent on the details, the NER provides the AER with the discretion to determine the size of the innovation allowance and how it should be applied.

In determining the size of the innovation allowance, the AER's current practice is to cap the total amount recoverable within a regulatory period based on its understanding of typical demand management and/or embedded generation connection costs. It then scales the amount to the relative size of each businesses average revenue allowance in the previous regulatory control period.

While the AER has itself acknowledged that the size of the innovation allowance is modest, it has also noted that it would be inappropriate to increase the amounts allocated for untested initiatives given that customers effectively fund the scheme.[44]

Furthermore, under the existing DMEGCIS framework, the AER cannot compel a distribution business to increase or spend their full allowance on non-network projects. This is because the funding is provided on a use-it-or-lose-it basis. If a distribution business is concerned about maintaining network security and reliability, this may

39 TEC, Rule change request, p.8.

40 COAG Energy Council, Rule change request, p.9.

41 AEMC 2012, Power of choice review - giving consumers options in the way they use electricity, Final Report, 30 November 2012, Sydney, Chapter 7.

42 COAG Energy Council, Rule change request, p.4; TEC, Rule change request, p.8. For an overview of the projects funded under the existing DMIA, see Appendix A of this consultation paper.

43 The factors are set out under NER clause 6.6.3(b).

44 See, for example, AER, Victorian Electricity Distribution Determinations 2011-2015 – Final Decision, October 2010, p.802.

outweigh the incentives available under the scheme for it to undertake riskier and innovative trial projects, the benefits of which may only materialise in the longer term.

The size of the innovation allowance allocated to a distribution business would be expected to reflect a balance between the benefits of encouraging exploration of innovative and riskier demand management projects and programs, and the costs to consumers of doing so. The AER currently makes this trade-off. This aspect of the consolidated rule change requests does not represent a change to existing practice, but rather would be codifying existing practice in the NER.

Reporting requirements

In light of the fact that the costs of the innovation allowance are born by consumers, the consolidated rule change requests propose to include an explicit obligation in the NER for distribution businesses to share the data, results and learnings gained from use of the innovation allowance with the AER, other network businesses and participants more broadly. Distribution businesses would also be required to publish details of approved projects in their DAPRs. These requirements together are intended to allow for shared learning, and will assist the AER carrying out its regulatory functions.

In effect, the proposed reporting requirements do not represent a significant change to existing practice. A key objective of the current DMEGCIS is to enhance industry knowledge of practical demand management programs through the annual publication of DMEGCIS reports from distribution businesses.[45] As such, the AER's current scheme requires the businesses to submit annual reports on outcomes and expenditure under the innovation allowance. In this sense, the proposals would act to codify existing practice in the NER.

Additionally, and as noted in section 6.1.2, the distribution annual planning report and demand side engagement obligations, introduced in October 2012, are intended to provide transparency around distribution businesses demand management initiatives and activities. Among other things, these will enhance industry knowledge of demand management and other non-network solutions to meet customer demand. They will also assist non-network providers to take a more informed view of the potential for non-network options to provide alternatives to network investment.

Regulatory treatment of demand management expenditure

An important aspect of the new incentive scheme under the consolidated rule change requests is that the innovation allowance would not be available to fund business as usual demand management projects. Funding for business as usual projects is expected to come from the normal expenditure allowances approved under clauses 6.5.6 and 6.5.7 of the NER.

However, it is important that the DMEGCIS arrangements are consistent with the broad principle that one form of capex or opex should not be favoured in its regulatory treatment over other forms. The consolidated rule change requests therefore propose to

45 AER, 2011-12 and 2012 DMIA assessment, Decision, July 2013, p.4.

require that the AER assesses the prudency of demand management related expenditure under the DMEGCIS in the same way as all other capex and opex, at each regulatory reset. This would retain, in all cases, the incentive for distribution businesses to implement the lowest cost approach to addressing a network limitation (in effect, there would be no bias for favouring network versus non-network options).

Consistent with the above, in its rule change request, the COAG Energy Council envisaged that the innovation allowance would be a time limited measure. That is, it would only be required in the short term, until such time as technology and knowledge evolves to a point where demand management options become business as usual. At this time, demand management activities would be funded through the normal expenditure allowances approved under clauses 6.5.6 and 6.5.7 of the NER.

Issue 3 Demand management innovation allowance

1. **Given that the proposed amendments in relation to the innovation allowance are largely reflective of existing AER practice, what additional benefits are likely to be gained by codifying these in the NER?**

2. **What impact, if any, will the proposed amendments have on distribution businesses incentives to utilise a greater proportion of their allocated allowances on innovative demand management projects, relative to current practice? For example, would greater certainty increase the likelihood of distribution businesses participating in this scheme?**

3. **Are the proposed amendments likely to address concerns raised by stakeholders around the size of the innovation allowances allocated by the AER to the distribution businesses (noting that, to date, these amounts have been considered to be modest)?**

4. **Given the new DAPR and DSES arrangements are now in place, what additional benefits will the proposed annual reporting requirements deliver to the market? Is there a risk of duplication in reporting for the distribution businesses?**

5. **Should the innovation allowance be a time-limited measure? If so, should the AER be given the flexibility and discretion to determine the appropriate timeframe?**

6.2.2 Demand management incentive scheme

As noted in section 3.2, the AER's current DMEGCIS has been applied in a very limited manner, operating essentially as a pass through of costs incurred in undertaking approved demand management projects, plus an innovation allowance.

In this sense the current DMEGCIS is not a true incentive scheme, in that it does not provide for businesses to earn extra rewards where defined goals have been delivered. In light of this, the distribution businesses may not be properly incentivised to explore and develop demand management options as efficient alternatives to network capital investment.

As noted by the AEMC in the Power of Choice review, an incentive scheme is only effective if it changes a business's behaviour and results in a net cost saving to consumers.

Based on the recommendations made by the AEMC in the Power of Choice review, the COAG Energy Council and the TEC have proposed amendments to the NER to create a more comprehensive incentive scheme. Specifically, the consolidated rule change requests seek to define in the NER an objective, set of principles and additional criteria regarding the development and application of the DMEGCIS.

The key proposals and associated issues related to the incentive scheme are discussed below.

Strengthening financial rewards under the scheme

The consolidated rule change requests propose to introduce a new clause in the NER which would explicitly allow the AER to implement a new incentive for distribution businesses, based on the broader supply chain market benefits created by demand management projects.

Under the current DMEGCIS applied by the AER, a distribution business would only retain the benefit that a demand management project creates for the delivery of distribution services (that is, a share of the reduced cost, assuming the quality of other aspects of distribution services do not change). However, a demand management project may create benefits at other levels of the supply chain, for example, a reduction in losses on the distribution network or avoided generator operating and capital expenditure). As these wider benefits do not translate into a financial outcome for a distribution business, some projects which may prove to be efficient from a NEM-wide perspective may not be privately profitable to the distribution business and consequently may not be pursued.

Distribution businesses who responded to the AEMC's Power of Choice review argued that the AER's current incentive scheme does not provide sufficient reward for pursuing demand management projects that generate wide social benefits.[46]

Based on recommendations made in the Power of Choice review, the COAG Energy Council and the TEC have proposed amendments to Chapter 6 of the NER to clarify that the distribution businesses would be able to retain a share of the market benefits delivered across the supply chain by an approved demand management project. The intent is to encourage businesses to pursue projects which deliver lower overall system costs, to the benefit of consumers.

46 AEMC 2012, Power of choice review - giving consumers options in the way they use electricity, Final Report, 30 November 2012, Sydney, pp.209-210.

To give effect to this, the COAG Energy Council has proposed changes to define that the scheme designed by the AER should provide for two types of rewards, namely:

- a payment based on a proportion of the market benefits and avoided or deferred network costs produced by a non tariff based demand management project; and
- a payment as compensation for any foregone profit due to a reduction in throughput volumes resulting from the implementation of non tariff demand management projects, where appropriate (this component is discussed separately in this Chapter).

The COAG Energy Council proposal would define in the NER what constitutes avoided distribution network costs and non-distribution related benefits, and how these benefits should be calculated. In addition, COAG Energy Council's proposed amendments include a requirement for the AER to develop and publish a guideline that sets out a consistent methodology or approach for identifying and calculating these benefits.[47]

Taking a slightly different approach but with the same purpose intended, the TEC has proposed to include a new requirement explicitly permitting distribution businesses to retain a share of the associated non-network related market benefits of demand management, as determined by the AER.[48]

Further, both the COAG Energy Council and the TEC consider that the share of market benefits retained by distribution businesses should be capped.

In its rule change request, the COAG Energy Council considers that the reward available to distribution businesses for demand management projects should be consistent with that available under broader incentive schemes for capital and operating expenditure in Chapter 6 of the NER and commensurate with any additional level of risk involved in developing such projects.[49] It has therefore proposed to introduce a requirement for the rewards for market benefits available under the scheme to be capped at no more than 30 percent of those market benefits. It considers that setting a cap in the NER has the benefit of promoting certainty for distribution businesses about the returns available for implementing demand management projects.

While the TEC also proposed to include a cap on the rewards for market benefits available under the scheme, it has proposed that this be set at 50 percent of those

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47 The approaches for calculation of market benefits under the incentive scheme should be consistent with how such benefits are determined under the RIT-D.

48 The TEC has proposed that this would be subject to two conditions. That is, where the business has made a material contribution to the demand management and where the demand management was unlikely to have been delivered without the business's support.

49 The NER provides the AER with the discretion to design the other incentive schemes set out under Chapter 6, including (where relevant) the ratio of sharing of the efficiency gains and losses between businesses and consumers (known as the incentive rate). Under the EBSS and CESS, the incentive rates are balanced, set at approximately 30:70 between the distribution businesses and consumers.

market benefits. This is because it considered the share of non-network market benefits achieved should be shared equitably between a business and consumers.

This aspect of the consolidated rule change requests represents a significant change to the current design and application by the AER of the DMEGCIS. The proposal also attempts to directly address one of the key issues identified with the current regulatory framework in relation to the motivations for distribution businesses to pursue demand management options as efficient alternatives to network investment.

For the regulatory framework to correctly facilitate the appropriate consideration of non-network options as an alternative to network investment, the framework needs to appropriately consider all the costs and benefits of a non network project or program. It also needs to compare the relative total lifetime costs of the demand management project or program to the capital asset costs. Such conditions would ensure that non-network solutions which are efficient from the perspective of the broader market, are identified. The introduction of the RIT-D arrangements in January 2013 was also designed to achieve this objective.[50]

Compensation for foregone revenue

As noted in Chapter 2, part B of the current DMEGCIS addresses the impact that certain forms of price control may have on a distribution business's incentives to undertake demand management. It applies to businesses that have standard control services subject to a certain form of control, such as a price cap, whereby the recovery of the annual revenue requirement is partially dependant on energy sold.[51] Businesses subject to this form of control could have a disincentive to reduce electricity sales, and hence to pursue demand management projects.

To remove this disincentive, part B allows a distribution business to recover any forgone revenue resulting from a reduction in the quantity of energy sold that is directly attributable to the implementation of a non tariff based demand management project approved under the innovation allowance (part A of the scheme).[52]

While not an explicit requirement in the rules, this approach is permitted under the current arrangements at the discretion of the AER.

50 The RIT-D process is intended to facilitate the discovery and adoption of the most economically efficient solution to address an issue on the network. Distribution businesses must apply the RIT-D in circumstances where a network problem exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $5 million. It requires distribution businesses to assess the costs and, where appropriate, the market benefits of each credible investment option to address a specific network problem to identify the option which maximises net market benefits (or minimises costs where the investment is required to meet reliability standards).

51 A non tariff demand management project that results in a reduction in the quantity of energy sold has the potential to reduce a distribution business's revenue. The AER has taken the view that, where a revenue cap applies to a distribution business, the recovery of allowed foregone revenue is not dependant on energy sales and as such, part B should not apply.

52 Only a distribution business to which the innovation allowance applies may be subject to part B of the scheme.

Both the COAG Energy Council and the TEC have proposed to include a new requirement in the NER to clarify that the DMEGCIS should include a payment as compensation for any lost revenues or profits that occur as a result of reduced demand from implementing a demand management option, where appropriate.

However, while the TEC has proposed to retain the foregone revenue component of the current scheme; the COAG Energy Council has proposed to base the payment on lost profit rather than revenue. It considered that profit based compensation would better recognise that demand management options can drive costs as well as revenues lower. As a consequence, businesses may not necessarily be worse off where they experience a loss in revenue from implementing a demand management project. Basing this component of the incentive scheme on foregone profit would therefore guard against over compensation.[53]

As noted above, this component of the incentive scheme is intended to address the impact that certain forms of control mechanism have on a distribution business's incentive to carry out demand management.[54] Distribution businesses whose annual revenue requirement is not dependant on energy sold – that is, those subject to a revenue cap - would not be applicable for this part of the scheme.[55]

The AER intends to move distribution businesses in New South Wales, Victoria and South Australia, previously regulated under a WAPC, to a revenue cap for the next regulatory control period. This is consistent with distribution businesses in Queensland and Tasmania.[56]This means that the majority of distribution businesses will not be eligible to receive payments under the foregone revenue (or profit) component of the incentive scheme in their next regulatory control periods.[57]

Additionally, and as is the case with other aspects of the consolidated rule change requests, this proposal would not significantly alter existing practice - the AER has included a foregone revenue component in its current DMEGCIS. Rather, it would codify existing practice in the NER.

53 To give effect to this element of the proposal, and to provide more certainty and clarity around its implementation, the COAG Energy Council proposed that the AER include a methodology for calculation of foregone profit component as part of the broader guideline.

54 Under the NER, the AER has the option (subject to certain criteria) to apply control mechanisms from a range which includes a revenue cap, a price cap, a weighted average price cap (WAPC) or an average revenue yield. In its recent decisions on the control mechanism, the AER has explicitly considered the different impact of these control mechanisms on volume risk and revenue recovery, incentives for demand management and price flexibility and stability.

55 For example, in its recent decision for New South Wales electricity distribution businesses, the AER noted that the move to a revenue cap control mechanism would remove NSW distribution businesses disincentive for demand management under the previous WAPC control mechanism. As such, the AER considered it appropriate to discontinue the recovery of foregone revenue through Part B of the DMIA.

56 The AER will continue to regulate the Australian Capital Territory under an average revenue cap for its next regulatory control period.

57 AER, Stage 2 Framework and Approach – NSW electricity distribution network service providers, March 2013; AER, Final Framework and approach for the Victorian Electricity Distributors - Regulatory control period commencing 1 January 2016, 24 October 2014, p.20.

Tariff based projects

Currently, recovery under part B of the current DMEGCIS is limited by the AER to revenue forgone as a result of non tariff demand management projects approved by it under part A of the scheme. While a distribution business may propose a tariff or non tariff based demand management project under the innovation allowance, it can only recover forgone revenue resulting from a reduction in the quantity of electricity sold due to the implementation of non tariff based demand management projects.

Tariff based demand management projects are those that aim to provide price signals to electricity customers at times of peak electricity demand, for example, critical peak pricing trials.

Both the COAG Energy Council and the TEC considered whether tariff based demand management projects should be included in the scope of the reformed incentive scheme. Having considered the potential risks and benefits, COAG Energy Council concluded in its rule change request that the proposed scheme should be limited to non tariff based demand projects only.

In contrast, the TEC proposed that both that price (tariff) based as well as project (non tariff) based demand management projects be included within the scope of the scheme on the basis that this would encourage more demand management.

The AEMC's recent distribution network pricing arrangements rule change will be implemented in all jurisdictions by July 2017. From this time, all distribution businesses will be required to set network tariffs which reflect the business' efficient costs of providing services to each consumer. It also provides a framework to require businesses to develop network tariff structures which appropriately incentivise efficient demand side responses by customers, for example, through shifting some consumption to lower cost off-peak times or by installing technologies that help reduce their peak demand.

Issue 4 Demand management incentive scheme

1. **If distribution businesses are able to receive a payment based on a proportion of the market benefits produced by a demand management project, is this likely to increase investment in projects that will deliver broader market benefits that are in the long term interests of consumers?**

2. **Given that the majority of distribution businesses are expected to be regulated under a revenue cap in the near future, is there value in amending the rules to explicitly require the inclusion of a payment for any foregone revenue resulting from implementing a demand management project approved under the innovation allowance? Should the AER retain discretion as to whether this component is appropriate?**

3. In light of the recent changes to the distribution network pricing arrangements, what are the potential benefits of requiring that the DMEGCIS include tariff based demand management options, in addition to non tariff based options?

7 Lodging a submission

The Commission has published a notice under section 95 of the NEL for this rule change proposal inviting written submission. Submissions are to be lodged online or by mail by 19 March 2015 in accordance with the following requirements.

Where practicable, submissions should be prepared in accordance with the Commission's Guidelines for making written submissions on Rule change proposals.[58] The Commission publishes all submissions on its website, subject to a claim of confidentiality.

All enquiries on this project should be addressed to Claire Rozyn on (02) 8296 7800.

7.1 Lodging a submission electronically

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code ERC0177. The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within three business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

7.2 Lodging a submission by mail

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission should be sent by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Or by Fax to (02) 8296 7899.

The envelope must be clearly marked with the project reference code: ERC0177.

Except in circumstances where the submission has been received electronically, upon receipt of the hardcopy submission the Commission will issue a confirmation letter.

If this confirmation letter is not received within 3 business days, it is the submitter's responsibility to ensure successful delivery of the submission has occurred.

58 This guideline is available on the AEMC website.

Abbreviations

AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CESS	capital expenditure sharing scheme
COAG	Council of Australian Governments
DAPR	distribution annual planning report
DMEGCIS	demand management and embedded generation connection incentive scheme
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DSES	demand side engagement strategy
EBSS	efficiency benefit sharing scheme
NEL	National Electricity Law
NEM	national electricity market
NEO	national electricity objective
NER	National Electricity Rules
opex	operating expenditure
Power of Choice	Power of Choice
RIIO	Revenue = Incentives + Innovation + Outputs
RIT-D	regulatory investment test for distribution
SCER	Standing Council of Energy and Resources
SSIS	small scale incentive scheme
STPIS	service target performance incentive scheme
TEC	Total Environment Centre

WAPC	weighted average price cap

A Demand management incentive allowance

A.1 Scope of the current demand management incentive allowance

The NER requires the AER to develop and implement mechanisms to incentivise distribution businesses to consider economically efficient alternatives to building network infrastructure. The demand management incentive allowance is one such mechanism. The AER's approach to date has been to provide distribution businesses with a capped allowance for each year of the businesses' regulatory control period.[59]

In response to the AER's approach, stakeholders have noted that the allowance is relatively limited in scope, currently providing between $100,000 and $1 million for each distribution business for each year of their regulatory control period.

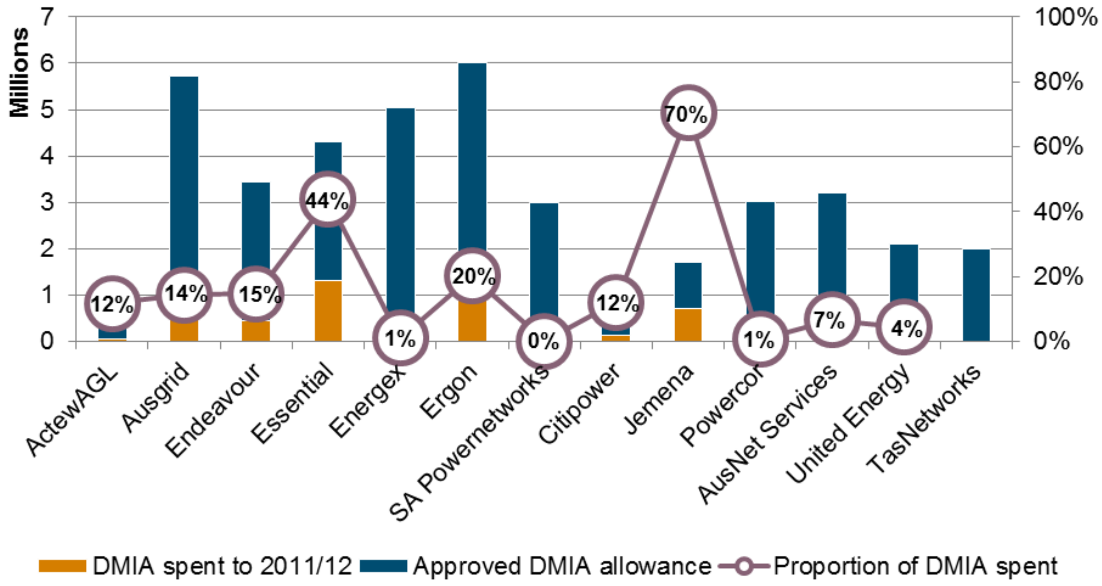
The 2011-12 and 2012 AER report on expenditure relating to the innovation allowance stated that non-Victorian distribution businesses claimed $2.2 million in expenditure. During this year, Energex and South Australia Power Networks did not claim an innovation allowance. To date (2009-10 to 2011-12), the non-Victorian distribution businesses have claimed around 14 per cent of the total innovation expenditure approved for their respective regulatory control periods.

Similarly, all of the Victorian distribution businesses claimed the innovation allowance in 2012. During 2012, this equated to approximately $564,000. To date (2011 and 2012), the Victorian distribution businesses have claimed approximately 11 per cent of the total innovation allowance approved for their current regulatory period.

Figure A.1 provides an overview of the allocation and expenditure relating to the innovation allowance for each distribution business for their current regulatory control period.

59 The NER does not prescribe any limits on the size of the innovation allowance.

Figure A.1 Demand management innovation allowance: allocation and expenditure



Source: AEMC Power of Choice Review - Final report, 2012.

A.2 Overview of activities undertaken with innovation allowance

Outlined in the table below are several examples of the demand management activities being undertaken by distribution businesses using expenditure from the innovation allowance.

Table A.1 Examples of projects funded under the innovation allowance

Distribution business	Project name	Project summary
Jemena[60]	Energy portal project	The energy portal is designed to enhance the demand management capability of consumers. It uses Advanced Metering Infrastructure technology to provide near real time consumption information to consumers. The innovation allowance expenditure was used to launch the portal and on enhancements to improve its functionality.
United Energy[61]	District Energy Services project	The aim of this project was to establish an operational, commercially feasible district energy services scheme in the Doncaster Hill Smart Energy Zone. The project sought to determine the extent to which district energy services could defer the requirement for network augmentation. The innovation allowance expenditure was used for the

60 Jemena, Extract from response to 2012 regulatory information notice – demand management incentive allowance report, June 2013, pp.3-8.

61 United Energy, Demand management incentive scheme report – 2012, January 2013, pp.4-6.

Distribution business	Project name	Project summary
		upfront work necessary to prove the concept.
SP AusNet[62]	Residential battery storage trial	The storage trial used stationary batteries connected to homes to simulate the potential characteristics of a demand management enabled electric vehicle. The trial explored how battery storage at the residential level could be used to alleviate peak demand, and develop insights into how electric vehicles may interact with the network in the future. The innovation allowance expenditure was used to cover the implementation costs (both capital and operating expenditure).
Ausgrid[63]	CBD embedded generation connection trial	The aim of this trial was to develop cost effective technical solutions to two key connection issues, those of: equipment fault level limitations, and feeder imbalance for high voltage connections. The innovation allowance expenditure was used to cover the program costs.

62 SP AusNet, Demand management innovation allowance annual report 2012, March 2013, pp.4-5.

63 Ausgrid, Demand management innovation allowance submission 2011-12 report to the AER, August 2012, pp.2-3.

B Ofgem framework for network innovation

The use of innovation allowances by regulators to facilitate change is not new. The following provides an overview of the network innovation allowance developed by Ofgem for network businesses in the UK.

Ofgem introduced the Revenue = Incentives + Innovation + Outputs (RIIO) framework[64] for setting a network business's allowed revenue for its regulatory control period.[65]

Innovation is a key element of the new RIIO framework. It achieves this by introducing a time-limited innovation stimulus package to provide additional funding.[66]

The innovation allowance is intended to fund certain research, development, and demonstration projects that can be speculative in nature and yield uncertain commercial returns and which shareholders may otherwise be unwilling to fund.

Currently, this innovation package only applies to electricity and gas transmission businesses and gas distribution businesses. It will be introduced to electricity distribution companies from 1 April 2015.

The innovation package consists of three measures:

- a **network innovation allowance** – a set annual allowance to fund smaller innovation projects that will deliver benefits to customers within a business's regulatory control period;
- a **network innovation competition** – an annual competition to fund selected flagship innovation projects that would deliver low carbon and environmental benefits to customers; and
- an **innovation roll-out mechanism** – to fund the roll-out of proven innovations which will contribute to the development in the UK of a low carbon energy sector or broader environmental benefits.

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64 Further information on the RIIO framework may be found at www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model.

65 Under RIIO, regulatory control periods in Great Britain are for an eight year period.

66 Further information on network innovation may be found at www.ofgem.gov.uk/network-regulation-%E2%80%93-riio-model/network-innovation.