Explanatory statement

Demand management incentive scheme

Electricity distribution network service providers

December 2017

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne Vic 3001

Tel: (03) 9290 1444
Fax: (03) 9290 1457

Email: AERInquiry@aer.gov.au
AER reference: 58882

Amendment record

Version	Date
01	14 December 2017

Shortened forms and glossary

Shortened form or term	Extended form or definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AR	annual smoothed revenue requirement as stated in the AER's post tax revenue model
ARENA	Australian Renewable Energy Agency
capex	capital expenditure
CESS	Capital Expenditure Sharing Scheme
committed project	has the meaning given in clause 2.2.2(1) of the Scheme
compliance report	the demand management compliance report required under clause 2.4.1 of the Scheme
credible option	has the meaning given to it in clause 5.15.2(a) of the NER
DAPR	Distribution Annual Planning Report
demand management	for the purpose of the Scheme, this relates to network demand management. This is the act of modifying the drivers of network demand to remove a network constraint.
demand management contract	has the meaning given in clause 2.2.2(2) of the Scheme
demand management proposal	has the meaning given in clause 2.2.2(3) of the Scheme
distributor	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
EEC	Energy Efficiency Council
efficient non-network option	has the meaning given in clause 2.2(2) of the Scheme
eligible project	as defined under 2.2.(1) of the Scheme
The ISF	the Institute for Sustainable Futures
kVA	a kilovolt -ampere or 1,000 volt-amperes
the Mechanism	the Demand Management Innovation Allowance Mechanism
MEU	Major Energy Users
minimum project evaluation requirements	as defined under clause 2.2.1 of the Scheme
MWh	megawatt hour or 1,000 kilowatt hours
NEM	National Electricity Market

Shortened form or term	Extended form or definition
NEO	National Electricity Objective
NER	National Electricity Rules
non-network option	has the meaning given in chapter 10 of the NER
NPV	net present value
opex	operating expenditure
preferred option	the credible option that maximises the present value of the relevant net benefit, where the credible option and the relevant net benefit are defined in this glossary
project incentive	the maximum financial incentive a project can accrue, as determined under equation 1 in the Scheme with respect to a project, i
relevant net benefit	the present value of the net economic benefit to all those who produce, consume and transport electricity in the relevant market (as defined in this glossary). To the extent that different market participants' costs and benefits cancel each other out, these costs and benefits must be identified but need not be explicitly calculated to the extent this does not affect the overall result of the calculation.
request for demand management solutions	means a request issued under clause 2.2.1 of the Scheme
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test for Distribution
SAPN	SA Power Networks
the Scheme	the Demand Management Incentive Scheme
the Scheme Objective	the Demand Management Incentive Scheme Objective
STPIS	Service Target Performance Incentive Scheme
total annual revenue	the total annual revenue given by the control mechanism the AER applies to the distributor, having applied any revenue smoothing, annual adjustments, carryovers and pass throughs
total financial incentive	means the sum of all project incentives accrued by a distributor in a particular regulator year, capped (where applicable) at the amount set out in clause 2.5(2) of the Scheme

Contents

1 Introduction

This explanatory statement accompanies the demand management incentive scheme (Scheme). We have designed the Scheme to promote the National Electricity Objective (NEO) by meeting the Scheme Objective to incentivise distribution network service providers (distributors) to undertake efficient expenditure on relevant non-network options relating to demand management.

We provide background on the type of demand management that this Scheme aims to incentivise. That is, 'demand management' as it relates to managing demand on electricity networks— the act of modifying the drivers of network demand to remove a network constraint.

This document explains our position, including how we have considered stakeholder submissions, on the following matters:

- Our rationale for applying the Scheme as part of the broader regulatory framework. It also describes how we intend to promote the NEO by meeting the Scheme Objective and principles in the National Electricity Rules (NER).
- How we will apply the Scheme in the regulatory determination process for individual distributors. This explains our decision to apply an incentive equalling up to 50 per cent of a distributor's expected efficient demand management expenditure.
- Our requirements for identifying and committing projects eligible for receiving incentives under the Scheme. It explains how we determine an 'eligible project', define demand management, and set requirements for evaluating and committing projects.
- The methodology for how distributors must determine the maximum incentive an eligible project can accrue (the project incentive). It explains how we cap the incentive a distributor can receive on any project at that project's expected net benefit across the relevant market, which is typically National Electricity Market (NEM).[1] This cap helps the Scheme to deliver cost savings to retail customers.
- Requirements for annual compliance reporting and how we intend to use compliance data.
- Proposed mechanism to deliver the incentive to a distributor after it has committed an eligible project. We cap the total financial incentive a distributor can receive in any regulatory year to 1.0 per cent of its annual smoothed revenue requirement for that regulatory year.

The majority of stakeholder input discussed in this explanatory statement comes from, but is not limited to, submissions on the draft Scheme.[2] There has been great

[1] The Scheme will apply to Power and Water Corporation from 1 July 2019, even though it is not part of the NEM. For this reason, the Scheme uses the term, 'relevant market', as opposed to the NEM.

[2] For a summary of submissions, see attachment C of this explanatory statement.

stakeholder interest and engagement in this project, and various stakeholder insights throughout the consultation process have informed the Scheme design. Stakeholders have shared these insights with us in the following forms:

- Prior to the Issues Day, 57 stakeholders responded to a pre-workshop survey by submitting to us their top three issues concerning network demand management and the development of the Scheme.
- 68 stakeholders attended our demand management Issues Day on 20 September 2016. Eight stakeholders gave presentations and all participants actively brainstormed views and solutions around key issues during 'breakout sessions'.
- 28 stakeholders lodged detailed submissions on a Consultation Paper we published on 4 January 2017.
- 42 stakeholders actively participated in a round table discussion at our demand management Options Day on 6 April 2017.
- 12 stakeholders that attended the Options Day lodged supplementary submissions following the Options Day.
- 51 stakeholders attended a Directions Forum videoconference on 29 June 2017.
- 23 stakeholders lodged detailed submissions on the draft Scheme and accompanying documents that we published on 28 August 2017.
- 29 stakeholders attended a pre-final workshop on 8 November 2017.

Where possible, we have made the material stakeholders provided to us publicly available on our website.[3]

1.1 Summary of the final Scheme design

Figure 1 outlines how the Scheme will operate. This combines a simple incentive delivery mechanism (that is, a cost multiplier) with constraints and in-built compliance checks designed to deliver benefits to retail customers.

[3] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism.

Figure 1: Outline of the Scheme operation

Application of the Scheme

AER's distribution determination specifies how the Scheme applies to a distributor for the regulatory control period.

↓

Identifying and committing eligible projects

Distributor identifies via RIT-D/minimum project evaluation requirements preferred and non-network options relating to demand management. It commits to deliverables for each project.

↓

Determining the incentive for eligible projects

Distributor determines the project incentive for a committed project that delivers a net benefit to retail customers.

↓

Compliance reporting

Distributor reports data on the past regulatory year, including the incentives it accrued, how it identified eligible projects, and the costs, benefits and outputs of committed projects.

↓

AER use of compliance report to review the financial incentive

AER reviews the total financial incentive a distributor accrued, with reference to the compliance report and total incentive cap.

↓

Application of incenitve payment

The total financial incentive a distributor accrued in regulatory year $t - 2$ is included in the distirbutor's total annual revenue for regulatory year t.

In tandem to publishing the Scheme and this explanatory statement, we have also published a demand management innovation allowance mechanism (the Mechanism) and accompanying explanatory statement.

2 Background on network demand management

The Scheme Objective is to incentivise distributors to undertake efficient expenditure on relevant non-network options relating to demand management. In this context, we consider 'demand management' relates specifically to managing demand on electricity networks. We define electricity network demand management as the act of modifying the drivers of network demand to remove a network constraint.

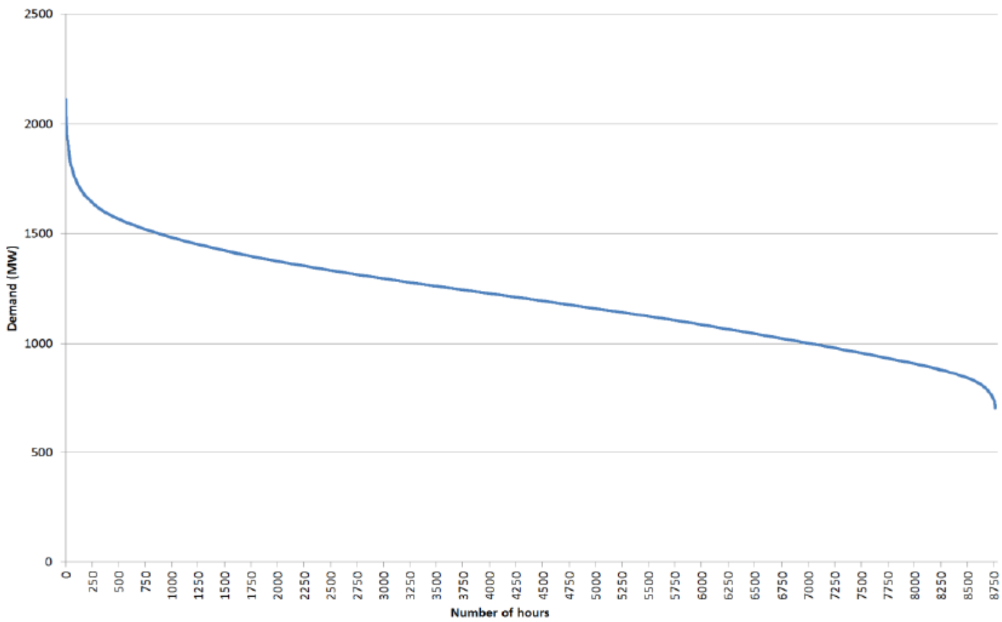
This definition recognises that demand management need not be specific to removing network constraints *at peak*. Rather, distributors can get value out of using demand management to remove network constraints driven by:

- peak demand;
- aging assets and risks associated with equipment failure;
- minimum demand and associated issues with voltage, system frequencies and power quality management; and
- the need to manage diverse power flows and system security issues.

2.1.1 Demand management and peak demand

While distributors build networks to meet peak demand, these networks only typically hit their peak for a very small fraction of time each year. At all other times, the network is underutilised. For example, figure 2 illustrates a typical load duration curve for a distributor, using Powercor in 2015 as an example. This load duration curve shows that while demand in Powercor's distribution network reached well over 2,000 MW in 2015, it was only at that level for a few hours in that year.

Figure 2: Example of a load duration curve



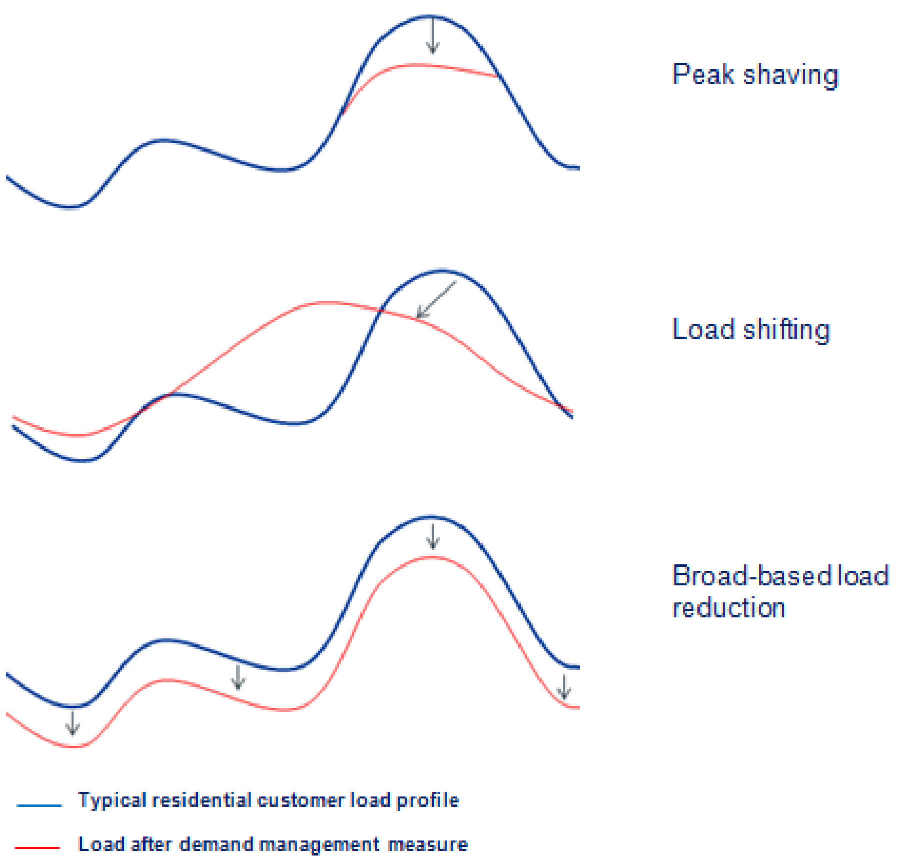
Source: CitiPower/Powercor, *Demand side engagement strategy*, 25 July 2016, v.2.0, Figure 3.2.

Demand management can reduce or shift the peak and provide a less costly alternative to network investment. Distributors can shift or reduce consumer demand through various methods, such as providing financial incentives to encourage behavioural change, providing local generation support or physically controlling electricity usage.

Figure 3 highlights three major demand management approaches:

- 'Peak shaving', which entails reducing demand at peak periods.
- 'Load shifting', which entails shifting demand to other times of the day when networks are less constrained, but can be broader than managing demand at peak (for example, it could also address minimum demand issues).
- 'Broad-based load reduction', which is also referred to as 'demand improvement' or 'energy efficiency'. At constrained parts of the network, distributors might use these measures to manage demand.

Figure 3: Some demand management approaches



In practice, electricity consumers will often implement these approaches, such as by changing their electricity usage in response to a price signal. To exemplify the differences, direct load control of air conditioning may have a peak-shaving impact, whereas high-efficiency air conditioners will have lower energy consumption whenever the air conditioner is operating.

2.1.2 Emerging uses for demand management

Over the past few years, network demand has generally flattened or reduced, and embedded generation has increased. As a result, peak demand increases have become a less widespread issue, typically only causing network constraints in certain geographic regions. Given this, peak demand reduction has been becoming a smaller part of demand management. For example:

- Some networks rarely face peak demand issues, but have aging assets and a need for redundancy support. In such instances, demand management can address risks associated with equipment failure, defer the retirement or replacement of aging assets,[4] or even offer smaller capacity replacement options.
- Where there are high levels of intermittent distributed generation, minimum demand can drive network constraints. While relatively rare at the moment, this issue may become more common as distributed generation construction continues. For instance, minimum demand can create technical challenges such as high voltage levels and system frequencies, as well as power quality issues from needing to manage diverse power flows.[5] Minimum demand challenges are expected to become more frequent over time. The Australian Energy Market Operator (AEMO) forecasts negative minimum demand in South Australia by 2027–28, as it expects that the electricity generated by rooftop photovoltaics will exceed customer demand in some hours.[6]
- It is no longer generally accepted that excess network capacity will eventually be met by peak demand growth. Rather, peak demand growth is recognised as particularly difficult to forecast (see figure 4). Demand management options can be particularly valuable when there are forecasting difficulties because, unlike network options, these tend not to lock in long-term irreversible investments. These options can have considerable 'option value' or flexibility benefits.[7]

---

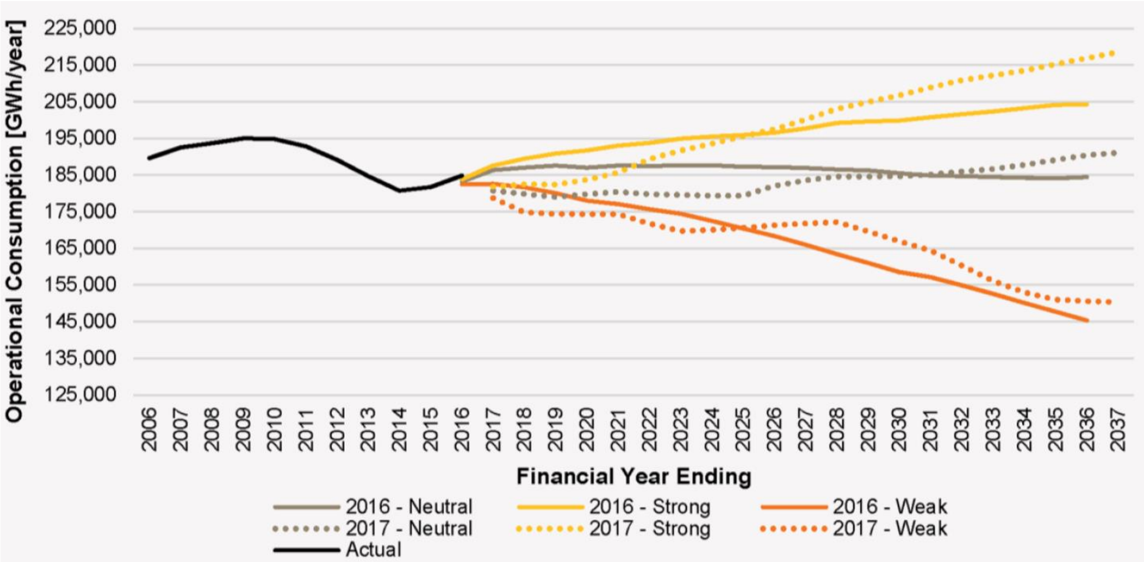
4 Ausgrid, *Submission to demand management consultation paper*, 23 February 2017; Ausgrid, *Submission on demand management incentive scheme and innovation allowance*, 12 October 2017, p. 1.

5 SA Power Networks (SAPN), *Submission to demand management consultation paper*, 24 February 2017; SAPN, *Supplementary note following demand management options day*, 21 April 2017; Energex, *Submission to demand management consultation paper*, 24 February 2017.

6 AEMO, *Electricity forecasting insights for the NEM*, June 2017, p. 8.

7 AEMO, *Submission to demand management consultation paper*, 28 February 2017.

Figure 4: Comparison of strong, neutral and weak scenario forecasts



Source, AEMO, *Electricity forecasting insights for the NEM*, June 2017, Figure 2.

2.1.3 Network demand management and other parties

The Scheme is neutral towards whether a distributor provides the demand management component of an eligible project in-house, as long as the in-house option is both:

- Permitted under other regulatory requirements. For instance, the national ring-fencing guideline requires distributors to implement ring-fencing arrangements between direct control services and other (negotiated and unclassified/unregulated) distribution services.[8] Other or future rules may also narrow the scope of demand management activities distributors can undertake, such as by limiting the scope for to include behind-the-meter assets in a distributor's regulatory asset base.[9]
- Maximising the expected net benefit of the preferred option. Any eligible project under the Scheme must have the highest expected net benefit across the relevant market, which will often be the NEM.[10] In achieving this, the Scheme should promote efficient outcomes that reduce electricity prices in the long term, all else being equal.

Nevertheless, we anticipate that a third party demand management provider or a distributor's ring-fenced affiliate (acting as a demand management provider) will typically provide the demand management component of an eligible project. A demand management provider could negotiate to share the benefits listed in figure 5 to the

---

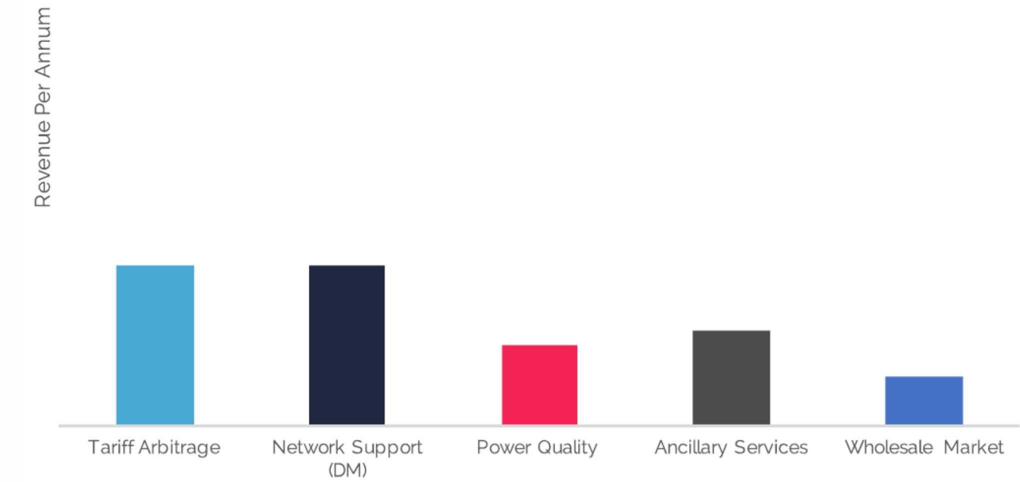
8 See clauses 3.1 and 4 of AER, *Ring-fencing guideline: Electricity distribution*, November 2016.

9 For example, see AEMC, *Draft rule determination: Contestability of energy services*, 29 August 2017.

10 The Scheme will apply to Power and Water Corporation from 1 July 2019, even though it is not part of the NEM. For this reason, the draft Scheme uses the term, 'relevant market', as opposed to the NEM.

parties accruing each of those benefits. By stacking and sharing these benefits, the demand management provider can spread the cost of providing its service across different parties. This should reduce the costs of the demand management service, relative to if the distributor provided it in-house as it could capture (or monetise) only a portion of these benefits. Figure 5 illustrates the concept of benefit stacking.

Figure 5: Illustration of stacking demand management's benefits



Source: Reposit Power, *Australian Energy Week presentation: Reposit customer grid participation progress update*, June 2017.

3 Rationale for the Scheme

The Scheme will operate alongside the separate Mechanism, which we have developed in tandem. The Scheme and Mechanism are targeted, achievable solutions that form a bridge between the current regulatory framework and a framework more focussed on efficient pricing of network services. While we have already taken steps towards the new framework, the transition to more efficient tariff structures is likely to take some time.

Our Better Regulation reform program in 2013 delivered a cohesive package of measures to support an improved regulatory framework.[11] These reforms improved distributors' incentives to undertake demand management. For instance, we reduced the distributors' incentives to undertake capital expenditure (capex) by revising how we set the allowed rate of return and introducing a Capital Expenditure Sharing Scheme (CESS). The package also included reforms stemming from the Australian Energy Market Commission's (AEMC's) Power of Choice review, including moving towards more cost reflective pricing and introducing the Regulatory Investment Test for Distribution (RIT–D). In addition to these changes, we have also reduced distributors' barriers to demand management by moving these businesses from a price cap to a revenue cap framework.[12]

Since our Better Regulation program, we have been implementing a range of complementary reforms. Some of these reforms promote competition; including introducing the national ring-fencing guideline for distributors and overseeing metering contestability arrangements that have recently commenced. We have also increased transparency in a way that will encourage a contestable market in facilitating demand management. For instance, we initiated a new rule that increases the availability of information on network businesses' plans to retire and replace assets.[13] We have also released an easier to understand distribution annual planning report template to assist non-network business in developing demand-side solutions to network constraints.[14]

Fully realising the benefits of these reforms will take time. For example, we agree with the AEMC's view that:[15]

---

11 For information on our Better Regulation reform package, see https://www.aer.gov.au/networks-pipelines/better-regulation.

12 Unlike the price cap framework, revenue caps do not create a disincentive for businesses to reduce demand. While we currently apply an average revenue cap to ActewAGL, we will apply a revenue cap in its next regulatory control period. See AER, *Framework and approach: ActewAGL regulatory control period commencing 1 July 2019*, July 2017, p. 11.

13 AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017.

14 AER, *Final decision: Distribution annual planning report template V1.0*, June 2017.

15 AEMC, *Rule determination: Demand management incentive scheme*, 20 August 2015, pp. 20–21.

> If networks priced efficiently and all electricity consumers were willing and able to respond to prices and manage their own demand, the need for the networks to manage peak demand would not be an issue.
>
> However, moving towards this outcome will take considerable time, given that it would require, among other things, the possible changes to the existing metering arrangements to be implemented and to take effect and for distribution businesses to develop tariffs that appropriately signal network costs.
>
> In addition, and perhaps more importantly, the market is unlikely ever to reach the point where price signals mean that there are no network constraints at peak times. This is because it would require highly volatile and very high prices at times of peak demand. It would also require all electricity consumers to be actively engaged and respond rapidly to price changes. In respect of the latter, consumer interests, motivation, willingness and ability to manage electricity use and costs depend on a range of different factors, of which the availability of demand side participation opportunities is just one.

The AEMC's view is consistent with our observations of the transition to more efficient tariffs. Distributors' plans to structure their tariffs over the next five years show a gradual move towards more efficient tariffs.[16] While this is welcome, it indicates that full transition is likely to require a considerable amount of time.

The full benefit of pricing reform will take time to flow on, but iterative improvements to achieve efficient outcomes are possible. For example, we have implemented reforms (such as the CESS) to adjust the balance of distributors' incentives between capex and operating expenditure (opex). Despite these recent adjustments, several experts and industry participants consider that there remain incentives to favour capex over opex. For instance:

- Many of the submissions to our demand management Consultation Paper expressed the view that the regulatory regime created a bias towards network capex over opex.
- The Institute for Sustainable Futures (ISF) undertook modelling that indicated a significant bias against demand management remains in the regulatory framework we apply to distributors.[17] It found that this bias arose from:
    - a general bias in favour of network capex solutions relative to non-network opex solutions;

---

16 For information on distributors' tariff structure statements, see: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs?f[0]=type%3Aaccc_aer_tariff_structure.

17 See ISF, *Re: Demand management incentive scheme supplementary submission*, 8 May 2017; Dunstan, C., Alexander, D., Morris, T., Langham, E., Jazbec, M., 2017, *Demand Management Incentives Review: Creating a level playing field for network DM in the National Electricity Market* (prepared by the ISF, University of Technology Sydney), June 2017.

- treating the recovery of demand management opex less favourably than other network opex; and
- distributors generally excluding future 'option value' when considering demand management solutions.

- In submissions to the AEMC's review of the 'contestability of energy services' rule change proposals, many stakeholders have expressed the view that a bias exists in the regulatory regime towards network capex over opex.[18] These views prompted the AEMC to explore whether the regulatory framework provides balanced incentives for distributors to use the most efficient mix of network or non-network options.[19] The AEMC will explore the issue of regulatory biases further within its 2018 electricity network economic regulatory framework review.[20]

In our view, this information indicates that distributors may face incentives to preference network options over non-network options. This bias is enabled in a variety of ways. For instance, when a distributor invests in network assets, capex is included in its regulatory asset base where it accrues the allowed rate of return over the life of the assets, which is typically decades long. This treatment of capex can create an incentive for a distributor to prefer network solutions to non-network solutions if the distributor and/or its investors:

- Prefer relatively stable long-term cash flows.
- Receive an allowed rate of return on regulated capex that is above its actual cost of capital, which would produce an opportunity for it to profit from its capex.
- Value the option to defer capex less than electricity consumers. Distributors face less down-side risk from overinvestment as the current regulatory regime allows them to pass the majority of these risks onto their customers. While our Better Regulation reform program introduced an ex-post capex review mechanism to better balance these risks, these ex-post reviews only apply in specific situations (for example, when a business has overspent its capex allowance on projects that do not meet the capex criteria).[21]

In the face of these conclusions, we consider there is value in improving how we regulate to encourage distributors to better utilise efficient demand management in managing their networks. However, when making these improvements, we must balance two important factors:

- Regulatory reform is necessarily a gradual process. The NEM is a complex ecosystem and its accompanying NER contain important and nuanced

---

18 See submissions under ERC0206 and ERC0218: http://www.aemc.gov.au/Rule-Changes/Contestability-of-energy-services; http://www.aemc.gov.au/Rule-Changes/Contestability-of-energy-services-demand-response.

19 See AEMC, *Consultation paper: National Electricity Amendment (Contestability of energy services, Contestability of energy services - demand response and network support) Rule 2016*, 15 December 2016, Question 7, p. 41.

20 See AEMC, *Draft rule determination: Contestability of energy services*, 29 August 2017, p. 55.

21 AER, *Better regulation: Capital expenditure incentive guideline for electricity network service providers*, November 2013, p. 13.

interrelationships. Given this, it is appropriate that major regulatory reform is subject to an effective consultative process.

- There is a risk of ‘letting the perfect become the enemy of the good’. That is, in the interim, significant opportunities to deliver value to electricity consumers via demand management could be lost. Moreover, where distributors see demand management as secondary to network alternatives, this may create a negative feedback loop that makes demand management options riskier and/or less efficient. This negative feedback loop means that:
    - The demand management services market has limited opportunity to mature, particularly when it comes to providing network support.
    - Distributors find themselves relatively inexperienced in relying on demand-side solutions to support their delivery of network services, including managing risks specific to these solutions.

Consequently, we see value in taking a two-pronged approach.

The first prong focusses on continuing to improve the way we regulate so that distributors have the incentive to utilise demand management wherever it is efficient to do so. In practice, this will entail:

- Transitioning further towards efficient pricing in distribution networks.
- Monitoring the effectiveness of recent regulatory reforms. For instance, distributors must comply with our ring-fencing guideline before 2018. We are also overseeing metering contestability arrangements that commenced 1 December 2017.
- Progressing further regulatory reforms where required, and contributing to various rule change proposals and energy market reviews. For instance, since 2014, the RIT–D has required that distributors engage with interested parties when selecting augmentation projects that deliver the most value to electricity consumers. While the RIT–D has helped put efficient demand management options on a more equal footing to network options, its narrow scope has limited its impact. Recognising this, we requested a rule change that now requires distributors to apply the RIT–D to replacement projects.[22] This rule should encourage distributors to consider efficient demand management on a business-as-usual basis when planning their networks.
- Continuing to engage with stakeholders on how we can improve the way we regulate, including on how we can improve our internal practices and processes for assessing expenditure and setting the allowed rate of return.

The second prong entails applying the Scheme as a bridge while regulatory and tariff reform progresses. The Scheme will financially reward distributors for undertaking demand management where it will deliver value and more efficient outcomes to

---

[22] AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017.

electricity consumers. We anticipate the Scheme will lead to lower prices for electricity consumers in the longer term. This position is consistent with Energy Consumers Australia's view that:[23]

> The [Scheme] could result in consumers funding increased network spending in one regulatory period to realise greater benefits of demand management in subsequent periods. Consumers accept the concept of funding developments on the condition that benefits are shared and outweigh costs over time. Such an eventuality would be acceptable to Energy Consumers Australia, provided engagement between networks, consumers and the AER allows the effectiveness of any [demand management] investment to be properly assessed.

The Scheme applies a simple mechanism, composed of the following:

- A cost multiplier incentive that provides distributors with a clear opportunity to earn a return for undertaking efficient demand management projects. This incentive will actively encourage distributors to seek demand management opportunities in managing and planning their networks.
- Features to moderate this cost multiplier so that the level of incentives available to distributors for demand management projects:
    - Takes into account the benefits that demand management delivers to electricity consumers. In particular, the incentive can only apply to projects that are estimated to, having undergone market testing, have the highest net benefit across the relevant market when addressing an identified need on the network. Also, we will set incentives so that consumers receive a net benefit from the project, even when we count the incentive as a cost to consumers.
    - Takes into account any subsidies directly provided to a distributor to provide demand management projects, to prevent consumers paying for incentives that are higher than necessary to promote efficient behaviour.
    - Is flexible, so we can adjust its magnitude over time. This adjustability recognises that as we continue to improve the way we regulate, the balance in regulatory incentives will change. For instance, there might be value in changing the magnitude of the incentive we provide under the Scheme in the future.

3.1 Giving effect to rule requirements

In designing any component of the regulatory framework, we aim to have it contribute to the achievement of the NEO, which is:[24]

---

23 ECA, *Submission to the AER's development of a Demand Management Incentive Scheme and Innovation Allowance*, June 2017, p. 4.

24 *National Electricity (South Australia) Act 1996*, Clause 7 of part 1.

> 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 price, quality, safety, reliability, and security of supply of electricity; and
> - the reliability, safety and security of the national electricity system

The Scheme will contribute to the achievement of the NEO by realising the Scheme Objective and principles in NER clause 6.6.3.

The Scheme Objective is to provide distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to demand management. In doing so, the NER require we develop and apply the Scheme to take into account the following principles:

(a) The Scheme should be applied in a manner that contributes to the achievement of the Scheme Objective.

(b) The Scheme should reward distributors for implementing relevant non-network options that deliver net cost savings to retail customers. We take this to mean that, all else being equal; projects that the Scheme incentivises should lead to lower prices for energy consumers. Relatedly, the Scheme should only incentivise demand management where it leads to more efficient outcomes.

(c) The Scheme should balance the incentives between expenditure on network options and non-network options relating to demand management. In doing so, we may take into account the net economic benefits delivered to all those who produce, consume and transport electricity in the market associated with implementing relevant non-network options.

(d) The level of the incentive:

   i. Should be reasonable, considering the long term benefit to retail customers. We take this to mean that the level of incentive should be sufficient to encourage distributors to produce efficient outcomes, but not be so high that it prevents these efficient outcomes from translating into lower long term prices for electricity consumers.

   ii. Should not include costs that are otherwise recoverable from any other source, including under a relevant distribution determination.

   iii. May vary by distributor and over time.

(e) Penalties should not be imposed on distributors under the Scheme.

(f) The incentives should not be limited by the length of a regulatory control period, if such limitations would not contribute to the achievement of the Scheme Objective.

(g) The possible interaction between the Scheme and:

   i. any other incentives available to the distributor in relation to undertaking efficient expenditure on, or implementation of, relevant non-network options;

ii. particular control mechanisms and their effect on a distributor's available incentives referred to in sub-paragraph (i) above; and

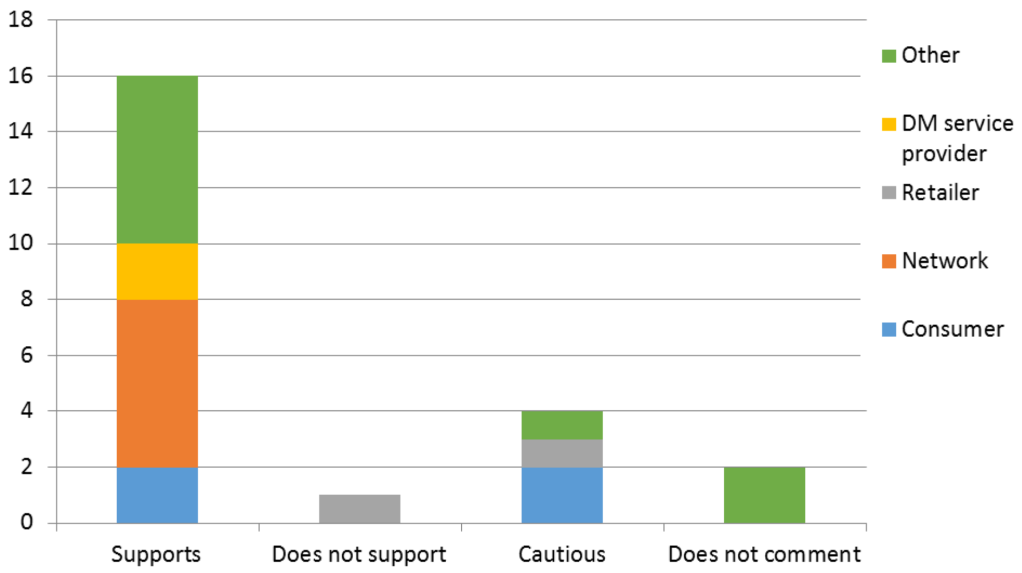
iii. meeting any regulatory obligation or requirement.

Moreover, under the NER, we must develop and publish the Scheme; and may, from time to time, amend or replace it in accordance with the distribution consultation procedures.

3.2 Stakeholder support for the Scheme

Throughout our consultation, the balance of stakeholder support has been in favour of a Scheme. For instance, stakeholder submissions on the draft Scheme generally supported it overall, as figure 6 shows. Also, submissions we received early this year on the Consultation Paper also demonstrated a similarly supportive view.[25]

Figure 6: Submission summary — high-level support of the draft Scheme



The following information also indicates that the balance of stakeholders favour introducing a Scheme:

- After we raised the question of whether a Scheme was required at the Options Day, stakeholders later lodged submissions citing the 'clear legal and policy intent' of the NER of the need for a Scheme.[26] Some noted that the substantive policy process addressed the question of whether a Scheme was necessary prior to the AEMC rule change, in support of implementing a Scheme.[27]

---

25 For a graph summarising stakeholder support for the Scheme in response to the Consultation Paper, see the presentation, AER, *Options day: Demand management incentive scheme & innovation allowance mechanism*, 6 April 2017, slide 6.

26 ISF, *Additional Submission post demand management options day*, April 2017, p. 2.

27 Total Environment Centre, *Additional Submission post demand management options day*, April 2017, p. 1.

- At the Options Day, there was general recognition among stakeholders that the Scheme would be the bridge towards the changing framework, as discussed above in section 3. For instance, the majority of stakeholders support the Scheme but recognise it is a Band-Aid. They consider there are bigger, unresolved issues such as whether there is a capex/opex bias. Also, fully cost reflective pricing is a complex and multilayered goal that will likely take a long time to achieve. In the meantime, many stakeholders see value in doing something quickly and simply so that 'the perfect does not become the enemy of the good'.
- Consumer groups have generally indicated they are willing to fund the costs of the Scheme and that they expect their initial investment will pay dividends through lower overall network charges by avoiding further infrastructure development.[28] Public Interest Advocacy Centre saw demand management playing a critical role in the future energy system and supported moves to better incorporate it as a tool to reduce costs, as well as providing other benefits.[29] While some consumer groups supporting greater use of demand management were hesitant to provide financial incentives to distributors, we consider there is value in doing so for the reasons set out earlier under section 3.[30] As an example, Energy Consumers Australia's (ECA's) submission following the Options Day stated that:

> Effective DM programs by networks are a critical measure to ensure that overall distribution network costs for consumers reduce over time…Investment has been made recently to meet forecast increases in peak demand though total consumption declined. DM (that is, strategies by network businesses to manage peak demand by means other than new network investment) offers the opportunity to ensure that this extra investment is not required and to hence reduce costs.
>
> The overall efficiency ‘prize’ on offer is potentially very significant.
>
> The DMIS could result in consumers funding increased network spending in one regulatory period to realise greater benefits of demand management in subsequent periods. Consumers accept the concept of funding developments on the condition that benefits are shared and outweigh costs over time. Such an eventuality would be acceptable to Energy Consumers Australia, provided

28 ECA, *Submission to the AER’s development of a Demand Management Incentive Scheme and Innovation Allowance*, June 2017, p. 2; QFF, *Re: Submission on the Demand Management Incentive Scheme and Innovation Allowance Mechanism, Consultation Paper*, January 2017, p. 2; SACOSS, *Submission on draft demand management incentive scheme, innovation allowance mechanism and proposed early application rule change*, 28 September 2017 ; TEC,*DMIS consultation paper*, February 2017, p. 2.

29 PIAC, *Re: Submission on the Demand Management Incentive Scheme and Innovation Allowance Mechanism, Consultation Paper*, January 2017, p. 3.

30 See NSWIC and Cotton Australia, *Re: Demand Management Incentive Scheme & Innovation Allowance Mechanism*, 24 February 2017, p. 4.

> engagement between networks, consumers and the AER allows the effectiveness of any DM investment to be properly assessed.[31]

While some stakeholders expressed concerns with the Scheme or considered it potentially unnecessary,[32] we do not agree with the basis for these concerns. For instance, Red and Lumo objected to the Scheme on the basis that a distributor's ring-fenced affiliate would price their demand side options lower than their competitors, knowing that this will be offset (within the distributor's corporate group as a whole) by the project incentive awarded to the distributor.[33] We understand, but do not agree with Red & Lumo's concerns. Following are our views on some potential market outcomes that encompass situations where the ring-fenced affiliate prices its demand side options lower than their competitors:

- The affiliate bid is the lowest bit, but is still above the affiliated entity's costs as a standalone entity, and the non-affiliated entities in the market could:
  - have offered a lower bid than this. This indicates that the affiliate was being more competitive. The affiliate may be accepting a lower profit margin and/or be a more efficient operator than other market participants. This efficient market behaviour provides value to electricity consumers.
  - not have offered a lower bid without providing the demand management service at a loss. This indicates that the affiliate has the lowest overall costs and is able to price better than their competitors. The affiliate would be providing an efficient service and value to consumers.
- The affiliate bid is lower than the level a non-affiliated company could offer and is below the affiliated entity's costs as a standalone entity, with the affiliated company using the incentive scheme to offset the loss. This would represent cross-subsidisation between the distributor and its ring-fenced affiliate, which should be prevented for the reasons outlined in the second dot point below.

We do not consider the Scheme will increase the risk of the latter of the above possibilities occurring. This is because:

- Under the Scheme, distributors receive financial incentives regardless of the identity of the other party with whom they contract for demand management services. Thus, the Scheme itself does not provide a reason for a distributor to favour its affiliate's projects over those of third parties. We also note that the identification of a particular project as an eligible project involves consideration of a wide range of costs and benefits that will impact on whether an affiliate's project or

---

31 ECA, *Submission to the AER's development of a Demand Management Incentive Scheme and Innovation Allowance,* June 2017.

32 Australian Energy Council, *Re: Demand management incentive scheme and innovation allowance mechanism: AEC submission following AER workshop*, April 2017; Business SA, *Submission on the draft demand management incentive scheme and innovation allowance mechanism*, 10 October 2017; Gill, M, *Response to AER's Options Day discussing the Demand Management Incentive Scheme*, April 2017.

33 Red Energy and Lumo Energy, *Re: Demand management incentive scheme and proposed early application rule change consultation paper*, 12 October 2017.

a third party project is identified as the eligible project for the purposes of the Scheme.

- The ring-fencing guideline is designed to prevent the use of regulated income, either directly or indirectly, in contestable markets.[34] Ring-fencing compliance is designed to prevent, detect and deter cross-subsidies. Reporting on the application of cost allocation methods would also detect the existence of such cross-subsidies between distribution services and non-distribution services.

It is also worth noting that while AGL previously voiced concerns about introducing the Scheme,[35] after reviewing the draft Scheme, it acknowledged it could provide a useful incentive in the short term. AGL also warned that the Scheme's existence should not impede more significant reform to enable more natural incentives for distributors to operate efficiently.[36] We see validity in this observation, which is consistent with our 'two-pronged' approach discussed earlier in this section 3.

34 See AER, *Ring-fencing guideline: Electricity distribution*, November 2016.

35 AGL, *Additional Submission post demand management options day*, April 2017, p. 1.

36 AGL, *Submission on the draft demand incentive scheme and innovation allowance mechanism*, 13 October 2017.

4 Application of the Scheme

Subclause 2.1(2)(a) of the Scheme specifies that our distribution determination will set out how the Scheme will apply to a distributor in the relevant regulatory control period.

If available and practical, we encourage distributors to provide information in their regulatory proposals on proposed demand management expenditure that may be eligible for project incentives under the Scheme. This information could also include the proposed network expenditure that proposed demand management projects under the Scheme may defer or avoid.[37] In developing regulatory proposals, distributors should also bear in mind that we prefer a 'base-step-trend' approach to assessing most opex categories when determining a distributor's opex allowance.[38]

The Scheme specifies that the cost multiplier applied to any eligible project must be that which is specified in the version of the Scheme that is current when the distributor commits the eligible project as per the requirements in clause 2.2.2 of the Scheme.

The Scheme specifies a cost multiplier of 50 per cent. Only one cost multiplier will apply to any committed project over the life of that project.

In the following sections, we explain our decision to:

- Apply the incentive as a cost multiplier.
- Set the cost multiplier in the Scheme rather than in the distribution determination or framework and approach.
- Set the magnitude of the cost multiplier to 50 per cent.

4.1 Applying the incentive as a cost multiplier

When designing the Scheme, we explored a variety of possible designs, including the possibility of not implementing a Scheme at all. Following our deliberations, we considered the most viable option would be to apply incentives under the Scheme as a function of demand management expenditure (that is, as a 'cost multiplier' or 'cost uplift'). In forming this view, we also considered designing the Scheme to apply incentives as a proportion of demand management projects' net benefits (that is, 'net benefit sharing').

The cost multiplier calculates incentives as a proportion of expected demand management expenditure. This provides distributors with an incentive to undertake

[37] ISF advised us to include this specification in the Scheme itself. However, we consider it is more appropriate to include this in the explanatory statement since this relates to the general distribution determination process as opposed to the Scheme itself.

[38] AER, *Better regulation: Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 32.

efficient projects, as they receive an explicit benefit from committing to demand management expenditure.

Following our consultation process, we consider that the cost multiplier is the most effective option. Our assessment took into account stakeholder views that indicated that the Scheme should include financial incentives, impose a small administrative burden, and not contribute to uncertainty. We consider that the cost multiplier is the better option to address these concerns compared with net benefit sharing.

As an option, the cost multiplier also received the most support from stakeholders at our Options Day, and was broadly accepted by stakeholders at the Directions Forum and the Feedback Forum. Submissions we received following the Options Day reiterated support for this preference, noting benefits such as its simplicity, relatively low administrative burden and flexibility.[39] As the submissions summarised in attachment C indicate, stakeholders generally supported the design we put forward in the draft Scheme, which was based on a cost-uplift. Exceptions to this support include submissions from:

- The Energy Efficiency Council (EEC), which prefers us to base to incentives on expenditure outcomes rather than expenditure itself, to avoid incentivising less cost-effective projects.[40]
- Major Energy Users (MEU), which noted that a cost multiplier would incentivise higher cost projects.[41] MEU advised that the Scheme must reward the lowest cost demand management option, and suggested we could improve the Scheme by either:
    - Assessing each demand management option in terms of total costs to consumers (that is, demand management cost plus incentive payment); or
    - Linking the incentive to value for consumers rather than the cost to networks.

We agree with the EEC and MEU that there are drawbacks to basing incentives on expenditure rather than 'outcomes' or 'benefits'. For this reason, we carefully considered an alternative Scheme design where we would base incentives on a proportion of the estimated benefits of demand management projects. Moreover, Oakley Greenwood advocated calculating incentives on benefits in their commissioned report for our draft Scheme as its first preference, as did the ISF in its submission on the Consultation Paper.

---

39 SAPN, *Additional note on AER demand management workshop*, April 2016, p. 2; United Energy, *Demand management incentive scheme and innovation allowance mechanism*, April 2017, p. 2.

40 EEC, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, October 2017.

41 MEU, *Submission on draft demand management incentive scheme and innovation allowance mechanism*, 9 October 2017.

While intuitively preferable, we considered that basing incentives on benefits would have important drawbacks. In particular, calculating market-wide benefits can be difficult, and is sensitive to the inputs and assumptions made by the entity performing the calculation. While Oakley Greenwood provided us with some worked examples for calculating certain benefits associated with demand management, these required employing approximation methods and assumptions.[42] Given the challenges and the potential subjectivity involved in estimating market-wide benefits, we do not consider it would be prudent to rely too heavily on these estimates when calculating the magnitude of incentives under the Scheme. We consider this might result in customers paying for expected benefits that are unlikely to occur. This makes it difficult to have certainty about the impact of the Scheme in this first iteration.

Moreover, we consider this difficulty is amplified by the currently limited understanding of demand management's market-wide benefits. While significant work is taking place in this area, the market's understanding of the benefits of demand management is still relatively limited, due to the infrequent deployment of demand management by distributors in Australia. Technological improvements appear to be driving new, sophisticated forms of demand management and altering the information available for calculating the benefits of non-network solutions with increasing pace.

In deliberating the limitations of tying incentives to both expenditure and benefits, we consider it important that the demand management incentive under the first version of the Scheme provides certainty. This certainty is better achieved at this time via a cost multiplier. Moreover, the cost multiplier will have a lower compliance burden as the incentive is not tied to the benefit calculation, which is sensitive to inputs. The new Scheme also contains components, such as the minimum project evaluation requirements, which encourage the public sharing and scrutiny of the net benefit calculations used by distributors. We consider that over time this will lead to a greater market understanding of how to calculate the benefits of demand management.

Additionally, calculations of net benefits cannot address potential non-financial barriers to demand management, such as a cultural bias among distributors. The cost multiplier is better suited to address this barrier, as it requires distributors to identify and commit to eligible projects and thereby receive a return for their effort. This could also provide a better impetus for the demand management services market.

We have also designed the Scheme to go some way to meet MEU's request to: ensure the Scheme rewards the lowest cost option, set the incentive with regards to total cost to consumers, and have a connection between the incentive and value to consumers.[43] For instance, we have designed the Scheme to:

- Only incentivise projects that have the highest net benefit, having undergone a transparent assessment process subjected to third party testing. This should result

[42] See Oakley Greenwood, *Advice on the DMIS incentive prepared for AER*, 23 June 2017, pp. 13–20.

[43] MEU, *Submission on draft demand management incentive scheme and innovation allowance mechanism*, 9 October 2017.

in the Scheme only promoting the lowest cost (or more accurately, the highest net benefit) option.

- Have a connection between the size of the incentive and the net benefits of projects. To be eligible for incentives, the net benefits of projects will inform (but not alone determine) the size of the incentive as a project's incentive cannot exceed that project's expected net benefits. In the long term, this will increase the market's ability to assess the benefits of demand management, while improving our ability to access those benefits, but mitigates the risk to consumers of miscalculating the benefits.

We consider that designing the Scheme with these safeguards is also consistent with the ISF's view. While the ISF preferred providing an incentive in the form of $/kVA of demand management at peak contracted, it also submitted the following on the approach of tying incentives to demand management expenditure:[44]

> such an approach could be effective if it is complemented with a rigorous measurement and verification system to ensure efficiency and value for money for consumers. Such an approach could also have potential benefits in the early stage of a [Scheme] in reducing uncertainty about funding and reducing the scope for complex technical and administrative processes.

4.2 Setting the cost multiplier in the Scheme

Every version of the Scheme will specify a cost multiplier to apply to any eligible project the distributor commits when that version is current.

We have proposed to set the cost multiplier in the Scheme itself, rather than in the distribution determination or framework and approach because doing so:

- Reduces the scope for repetitive debate across different regulatory resets regarding setting the magnitude of the cost multiplier.
- Allows us to vary the cost multiplier by varying the Scheme. This will affect all distributors and will allow us to consult broadly by following the distribution consultation procedures. We consider this appropriate given that, in our view, we are more likely to vary the cost multiplier following changes to regulatory incentives, evidence of the magnitude of economic benefits and market developments that affect distributors to which the Scheme applies.
- Allows us to adjust the cost multiplier mid-regulatory control period without having to reopen the determination. We have this flexibility because the applicable cost multiplier for a project is the one in the current version of the Scheme when that project is committed, and not a cost-multiplier fixed in the distribution determination. This feature provides us with flexibility to adjust the power of the incentive over time. This flexibility can be particularly valuable given the market for demand

---

[44] ISF, *RE: Demand Management Incentive Scheme Supplementary Submission*, 8 May 2017, p. 9.

management appears to be rapidly evolving and we anticipate more evidence of demonstrable economic benefits once the Scheme is operational.

ECA also submitted that it was important for consumers to be able to engage with distributors and us in assessing the effectiveness of any demand management investment.[45] While we may adjust the cost multiplier over time, the new incentive will only apply to new projects prospectively (that is, we will not apply an ex-post adjustment for projects that distributors have already committed). Distributors will make investment decisions having regard to the cost multiplier. We see value in balancing the benefits of having a flexible Scheme against the benefits of promoting regulatory certainty that can support informed investment decisions.

Of the submissions we received on the draft Scheme, only AusNet Services voiced an alternative preference to set the magnitude of the multiplier at the distribution determination stage. AusNet Services recognised that while we had mitigated some regulatory risk by guaranteeing not to change a project's uplift after the distributor has made a project commitment, it felt this insufficiently limited regulatory risk for projects that were in the pre-commitment negotiation stage.[46] We consider the benefits of increased flexibility and reduced regulatory costs outweigh what AusNet Services considers to be the cost of this approach. Moreover, we do not consider our approach creates regulatory risk for projects in the pre-commitment negotiation stage as we must follow distribution consultation procedures before we can amend the magnitude of the incentive in the Scheme.[47] We consider this will provide sufficient lead-time for distributors to progress and negotiate projects to the commitment stage in advance of any such change and/or in the knowledge that such a change is possible within the timeframe required by the distribution consultation procedures.

4.3 The magnitude of the cost multiplier

The Scheme specifies that the cost multiplier is 50 per cent. We will consider varying the cost multiplier in future versions of the Scheme. For instance, we anticipate there may be a future need to adjust the cost multiplier:

- Downwards if there are compliance breaches under the Scheme.
- Downwards, but also possibly upwards in response to regulatory changes that affect distributors' incentives to undertake efficient demand management. Since the regulatory framework is evolving to better facilitate efficient investment decisions, we consider an upwards movement unlikely.

45 ECA, *Submission to the AER's development of a Demand Management Incentive Scheme and Innovation Allowance, June 2017*, p.4.

46 Ausnet, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017.

47 NER cl. 6.6.3(d) allows us to amend or replace the Scheme in accordance with the distribution consultation procedures set out in Part G of Chapter 6 of the NER. Under these procedures, we must provide at least 30 business days for stakeholders to make submissions on any proposed amendment to the Scheme (with an accompanying explanatory statement to explain the proposed amendment).

- Downwards, but also possibly upwards in response to market changes that affect the likelihood of distributors undertaking efficient demand management. We consider the market for demand management services is new and growing and will likely develop to provide more relevant and efficient services. These developments should increase the likelihood that distributors will undertake more efficient demand management.
- Upwards if distributors face a greater imbalance in incentives against demand management than was initially considered when setting the cost multiplier.

We recognise that setting a cost multiplier is not a perfectly precise exercise. At this point, the demand management market is immature and there is considerable uncertainty about its costs and benefits. Any calculation of the net benefits necessarily requires assumptions and projections. As the demand management market matures, more accurate estimates of net benefits will hopefully develop.

An 'ideal' incentive would be calculated on a project-specific basis, as supported by submissions that considered the 50% cost multiplier might be either too high or too low in particular circumstances.[48] However, we nevertheless consider that 50 per cent is a reasonable cost multiplier to apply as a starting point for the Scheme, and is reasonably consistent with stakeholder submissions (as discussed below). It is also equivalent to receiving an allowed rate of return of 6.3 per cent compounded semi-annually over approximately 6.5 years.[49] We do not consider this to be an unreasonable magnitude for an incentive, which we have estimated using the compounding interest formula in equation 1.

Equation 1: Effective years to receive 50 per cent return

$$Future\ value = Present\ value \times (1 + rate\ per\ compound\ period)^{compound\ periods}$$

$$1.5 = 1 \times (1 + \frac{0.063}{2})^{2\times x}$$

$$\ln(1.5) = 2x \times ln(1 + \frac{0.063}{2})$$

$$\frac{\ln(1.5)}{ln(1 + \frac{0.063}{2})} = 2x$$

$$x = \frac{\ln(1.5)}{2 \times ln(1.0315)} \approx 6.5\ years$$

48 EEC, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, October 2017; ISF, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017; MEU, *Submission on draft demand management incentive scheme and innovation allowance mechanism*, 9 October 2017.

49 6.3 per cent is the average of the allowed rate of returns which we applied in our most recent distribution determinations for distributors across ACT, NSW, Queensland, SA, Tasmania and Victoria.

In our view, a cost multiplier of 50 per cent broadly aligns with stakeholder submissions. For instance, this is:

- On the lower side of the ISF's suggested cost multiplier range of between 40 and 104,[50] or 40 to 90 per cent.[51]
- Consistent with the magnitude of 25 or 50 per cent that GreenSync proposed in its submission to our Consultation Paper.[52]
- Generally supported by submissions on the draft decision. While in some circumstances, ISF and EEC considered the 50 per cent cost multiplier might be too conservative,[53] MEU considered it might be too generous.[54] On MEU's point, we note that in circumstances where the net benefit constraint binds, the effective cost multiplier will be less generous than 50 per cent.
- Higher than the cost multiplier suggested in United Energy's supplementary submission following the Options Day that equated to the nominal vanilla WACC on a one-off basis,[55] and higher than Red and Lumo's submission that, if the Scheme is made or applied at all, the cost multiplier should be set at 10 per cent.[56]
- Higher than the cost multiplier Oakley Greenwood recommended we apply to the three projects it considered —which would be 7.4, 8.4, and 26.5 per cent.[57] However, Oakley Greenwood based these estimates on an approximation of option value alone, whereas we recognise there might be value in considering a broader range of benefits associated with demand management when determining the magnitude of the cost multiplier.

Of these submissions, we give a notable amount of consideration to the ISF submission, as the ISF has been particularly active in providing analysis to inform what an appropriate magnitude might be. The ISF ran a 'Network demand management incentives stocktake project' with support from the Victorian Department of Environment, Land, Water and Planning (DELWP) and the Australian Renewable Energy Agency (ARENA), as an A-lab study. Both network and non-network stakeholders collaborated in this project and we participated as an observer. The study

---

[50] ISF, *Re: Demand management incentive scheme supplementary submission*, 8 May 2017, p. 11.

[51] Dunstan, C., Alexander, D., Morris, T., Langham, E., Jazbec, M., 2017, *Demand Management Incentives Review: Creating a level playing field for network DM in the National Electricity Market* (prepared by ISF, University of Technology Sydney), June 2017, iv.

[52] GreenSync, *Demand management incentive scheme & innovation allowance mechanism consultation paper*, 25 February 2017, p. 3.

[53] EEC, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, October 2017; ISF, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017.

[54] MEU, *Submission on draft demand management incentive scheme and innovation allowance mechanism*, 9 October 2017.

[55] That is, 6.37 per cent. See United Energy, *Demand management incentive scheme and innovation allowance mechanism*, 19 April 2017, p. 2.

[56] Red Energy and Lumo Energy, *Re: Demand management incentive scheme and proposed early application rule change consultation paper*, 12 October 2017.

[57] Oakley Greenwood, *Advice on the DMIS incentive prepared for AER*, 23 June 2017, pp. 15–17.

quantitatively analysed the impacts of regulation and incentives for networks to undertake demand management and the impact of these incentives on consumers. As an output, the ISF has produced a quantitative model for valuing network and non-network options under different scenarios, which formed its submission on our Consultation Paper that recommended an incentive in the form of $/kVA at peak per year.

During the Options Day, a number of stakeholders expressed a preference towards applying an incentive under the Scheme in the form of a cost multiplier. Following this discussion, in its supplementary submission, the ISF also suggested an incentive that could be applied in the form of a cost multiplier, although an appropriate uplift level would vary depending on which identified need the distributor is considering. It recommended a cost multiplier of between 40 and 104 per cent, but also suggested we examine a wider range of case studies and assumptions.[58] In its final report to ARENA, it narrowed its recommended cost multiplier range to be between 40 and 90 per cent.[59]

58 ISF, *Re: Demand management incentive scheme supplementary submission*, 8 May 2017, p. 11.

59 Dunstan, C., Alexander, D., Morris, T., Langham, E., Jazbec, M., 2017, *Demand Management Incentives Review: Creating a level playing field for network DM in the National Electricity Market* (prepared by the ISF, University of Technology Sydney), June 2017, iv.

5 Identifying eligible projects

Clause 2.2 of the Scheme defines the type of projects that it will apply to ('eligible projects'). Table 1 summarises the elements of an eligible project. It also explains how each element will give effect to the NER, and how it incorporates stakeholder views.

Table 1: Elements of project eligibility

Element required for 'eligibility'	Rationale for element	Regard to stakeholder views
When identifying whether a project is an efficient non-network option, a distributor has either completed a RIT–D or 'minimum project evaluation requirements'.	This element acts an in-built compliance check to verify that the Scheme is only incentivising efficient projects that deliver cost savings to retail customers, by: • Requiring the distributor conduct a cost-benefit analysis of its credible options for addressing network constraints; and • Subjecting this analysis to third party testing.	We only require a distributor follow 'minimum project evaluation requirements' before accessing incentives for non-RIT-D projects. We agree with the views expressed by some stakeholders in response to the Consultation Paper that we should not add requirements where existing processes, like the RIT-D, already address the relevant issue. We further explain how we set the specified 'minimum project evaluation requirements' in the section, below.
To be an efficient non-network option, it must be a credible option to meet an identified need on the distribution network.	This is required to give effect to the Scheme Objective, which entails incentivising 'non-network options', which the NER ties to addressing identified needs.	In their submissions on the draft Scheme, Energy Queensland and the Clean Energy Council questioned tying the Scheme to identified needs on the basis that this would connect demand management to an alternative network option.[60] We considered and discussed this view at the Feedback Forum. While tying the Scheme to identified needs is required by the NER, we have made other amendments since the draft Scheme to avoid unnecessarily connecting demand management to alternative network options, such as removing unnecessary references to 'network options'.[61]
To be an efficient credible option, it must be the preferred option— that is, it must maximise the present value of the net economic benefit to all	Adopting the term 'preferred option' used in the RIT-D: • Streamlines the assessment process with the RIT-D.	This position is consistent with many stakeholders' views that support efficiency assessments at the network planning stage.[62] While some stakeholders caution against

[60] CEC, *Submission on draft demand management incentive scheme*, 12 October 2017; Energy Queensland, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 17 October 2017.

[61] See AER, *Presentation: Demand management feedback forum*, 8 November 2017, slides 8–9.

[62] Ausgrid, AusNet Services, ENA and United Energy indicated this position when arguing against demand management targets in their submissions to our Consultation Paper. For instance, United Energy submitted that ' a demand management solution should only be adopted if it is the most economic option (in maximising the net market benefits). See United Energy, *RE: Consultation paper – Scheme and Allowance Mechanism*, 24 February 2017, p. 6.

those who produce, consume and transport electricity in the relevant market. For clarity, the expected relevant net benefit of the preferred option must have a positive NPV when assessed against a base case of doing nothing, unless the project is for reliability corrective action.	• Captures the concept of 'net economic benefits' referred to in NER cl. 6.6.3(c)(3). • Aligns with an 'efficient non-network option', which we interpret as needing to meet an identified need/network constraint.	quantifying broad market benefits, others specifically supported this approach.[63] We consider this analysis necessary to deliver the NER's intent, but note it also involves cost, complexity, and elements of subjectivity. We have adopted some suggestions ISF put forward in its submission to the draft Scheme.[64] For instance: • To assist in reducing the regulatory burden, we have removed the specification in the draft Scheme that connected the net benefit analysis under the Scheme to the RIT–D. We have also provided some high-level guidance in attachment A.1 of this explanatory statement on the level of analysis we might expect in a net benefit test for small (non-RIT–D) projects under the Scheme. • To help streamline the net benefit calculation to better focus on the end-impact to consumers, we have introduced some simplicity by clarifying that distributors need not calculate the specific costs and benefits that cancel out between different parts of the electricity supply chain (that is, wealth transfers). We have provided this clarification in our definition of 'relevant net benefit' in the Scheme's glossary.
It is a non-network option relating to demand management, where demand management is the act of modifying the drivers of network demand to remove a network constraint.	Eligible projects must be non-network options relating to demand management to achieve the Scheme Objective under NER cl. 6.6.3(b).	In response to stakeholder views, we broadened our definition of 'demand management' for the draft Scheme so that the network constraint need not be only 'at peak'.[65] Stakeholders generally supported this change in their submissions on the draft Scheme.
Would not have had expenditure committed to it by a relevant distributor before the first application of the Scheme to that distributor.	Added for avoidance of doubt. Rewarding decisions made prior to the Scheme's commencement would create a cost to retail customers that is independent of whether the Scheme incentivised efficient investment decisions.	Not applicable.

63 For instance, Dr Martin Gill cautions against distributors' ex-ante cost-benefit analyses of demand management projects. See Gill, M., *Submission: Demand management incentive scheme*, 11 February 2017; Gill, M., *Response to AER's Options Day discussing the demand management incentive scheme*, 21 April 2017. In contrast, Dunstan et al view the consideration of net market benefits as important for overcoming the underutilisation of efficient demand management. See Dunstan, C., Alexander, D., Morris, T., Langham, E., Jazbec, M., 2017, *Demand Management Incentives Review: Creating a level playing field for network DM in the NEM* (Prepared by the ISF, UTS), June 2017.

64 ISF, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017.

65 For a detailed discussion supporting why we broadened our definition of demand management, see AER, *Explanatory statement: Draft demand management incentive scheme*, August 2017, pp. 35–37.

An important process for meeting the requirements in table 1 entails following 'minimum project evaluation requirements', which we set out in clause 2.2.1 of the Scheme. These requirements set out the competitive testing that distributors must undertake before a non-RIT-D project can be eligible to receive incentives under the Scheme. This competitive testing entails:

- Issuing a request for demand management solutions to other legal entities that could provide the demand management product, service or solution needed to meet, or contribute to meeting, the identified need on its network.
- Including, within that request for demand management solutions, material that allows other legal entities to make informed responses in presenting a credible options to meet the identified need.

Once a distributor completes this competitive testing, it will identify whether a non-network option relating to demand management has the highest net benefit across the relevant market. If it does, it will contract or sign off on the costs and deliverables of the demand management to make that project a committed project (see section 6).

For clarity, a distributor is obliged to comply with the minimum project evaluation requirements only if it is seeking financial incentives under the Scheme.

5.1 Issuing requests for demand management solutions

When following the minimum project evaluation requirements in the Scheme, a distributor will issue a request for demand management solutions to the following parties:

- Persons registered on its demand side engagement register. This register is a facility by which a person can register with a distributor their interest in being notified of developments relating to distribution network planning and expansion.[66]
- Any other parties the distributor may identify as having or potentially having the capabilities to provide a demand management product, service or solution needed to either fully or partly form a credible option to address the identified need on the distribution network.

It is appropriate for distributors to issue requests for demand management solutions to persons registered on its demand side engagement register as this is a fit-for-purpose pre-established facility. In fact, distributors already use this facility for similar purposes. For instance, when a distributor is a RIT–D proponent, it must consult with persons registered on its demand side engagement register. It must notify them when it publishes a non-network options report and requests submissions on its draft project assessment report.[67]

[66] NER cl. 5.10.2.
[67] NER, 5.17.4.

5.2 Information in the request for demand management solutions

The Scheme specifies that, accompanying the request for demand management solutions, a distributor shall provide the following information:

- A description of the identified need that the distributor is seeking to address.
- Key technical information, including the load at risk, energy at risk, duration and load curves, the annual probability and frequency of events, and expected value of energy at risk.[68] The value of energy at risk must be based, at a minimum, on the average volume of energy at risk, the weighted probability of the energy at risk event occurring, and the relevant value of customer reliability for a given regulatory year.
- The location of the identified need and a description of the affected classes of customers and network area.
- If the distributor has already identified an initial preferred option to meet the identified need on the distribution network, a description of its initial preferred option. Where available, this information can serve as a benchmark to help other parties respond to the request for demand management solutions. We agree with ISF and SA Power Networks that it would not always be beneficial to provide this information.[69] For example, where non-network options are likely to be the most economic options, testing the market would be the most logical and beneficial first step.
- Other information sufficient to allow parties receiving the request for demand management solutions to make an informed response in presenting an alternative potential credible option. In the context of determining what constitutes 'other information', a distributor should have regard to the information required in non-network options reports.[70]

The intent of these requirements is to require distributors to provide sufficient information to allow parties receiving the request for demand management solutions to make an informed response in presenting an alternative (potential) credible option. However, we have also balanced this against setting prescriptive requirements that may not always be fit-for-purpose.

The Scheme specifies that distributors should have regard to the information required in non-network options reports. While this is not prescriptive, it recognises that the contents in a non-network options report would typically include information that would

---

68 The draft Scheme did not specify the need to include the expected value of energy at risk. We added this requirement in response to ISF's suggestion in ISF, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017.

69 ISF, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017; SAPN, *Submission on the draft demand management incentive scheme, innovation allowance mechanism and proposed early application rule change*, 12 October 2017.

70 NER, 5.17.4(e).

assist parties in making informed responses to a distributor's request for demand management solutions. This is because a non-network options report and request for demand management solutions would serve a similar function in allowing parties to identify the scope for, and develop, alternative potential credible options or variants to the potential credible options.[71]

NER clause 5.17.4(e) outlines the contents of non-network options reports, which include:

- A description of the identified need.
- The assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why reliability corrective action is necessary).
- If available, the relevant annual deferred augmentation charge associated with the identified need.
- The technical characteristics of the identified need that a non-network option would be required to deliver, such as:
  - the size of load reduction or additional supply;
  - location;
  - contribution to power system security or reliability;
  - contribution to power system fault levels as determined under NER cl.4.6.1; and
  - the operating profile.
- A summary of potential credible options to address the identified need, including network options and non-network options.
- To the extent practicable, for each potential credible option, information on:
  - a technical definition or characteristics of the option;
  - the estimated construction timetable and commissioning date (where relevant); and
  - the total indicative cost (including capital and operating costs).
- Information to assist non-network providers wishing to present alternative potential credible options, including details of how to submit a non-network proposal.

[71] A non-network options report must have regard to this under NER 5.17.4(f).

6 Committing eligible projects

The Scheme specifies that once a distributor identifies an eligible project, it will make a project commitment supported by written documentation. This documentation must take either of the following forms:

- A 'demand management contract' the distributor has entered with another legal entity. Under this contact, a distributor will pay that legal entity to manage network demand by a specified kVA per year. This demand management might be at the distributor's influence, request or control.[72] It may also be at the other legal entity's influence, request or control. For clarity, a distributor's ring-fenced entity can constitute another legal entity. Payment under this demand management contract must be tied to a specified kVA per year of network demand that can be modified at the distributor's or the contracted party's influence, request or control; or
- A 'demand management proposal', but only if and where the distribution ring-fencing guideline and any other relevant laws, rules and regulatory requirements, permit a distributor to provide demand management under an eligible project in-house, and doing so maximises the expected net benefit of the preferred option across the relevant market. The demand management proposal sets out the means by which the distributor can influence or control network demand. The proposal must specify the amount of demand the distributor can influence or control, expressed in terms of kVA per year. This proposal also sets out the costs that the distributor expects to incur in managing, or having the capacity to manage demand on its network in this manner.

We have included a requirement for distributors to set deliverables when committing to projects because this provides greater assurance that we are linking incentives under the Scheme to demand management deliverables.

6.1 Rationale for the demand management contract

The most practical and transparent way for a distributor to commit to deliverables is via specifying them in a contract with another legal entity from which it is procuring a demand management product, service or solution. Under this demand management contract, the other legal entity must commit to having the capacity to manage network demand by a specified kVA per year. The purpose of this is to promote transparency, accountability and performance measurement under the Scheme.

The Scheme provides the distributor with discretion on how to structure payments for availability versus dispatch under a demand management contract. However, the

[72] We added 'influence' to this specification so the Scheme is sufficiently flexible to incentivise passive demand management measures, where efficient (for example, geographically-targeted energy efficiency programs). This captures ISF's suggestion from *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017.

expected costs of this contract must align with the unit prices and its probabilistic assessment of future demand.

Example 1 provides a simple illustration of expected costs under a demand management contract.

Example 1: Illustrative demand management contract and expected costs

Assume a distributor forms a demand management contract for the next year based on the fees in table 2. Also, assume that given the distributor's assessment of future demand, the weighted average probability that it will dispatch its total contracted capacity is 10 per cent.

Table 2: Fees and expected costs under hypothetical contract

Type of demand management	Load available per year (kW)	Capacity fees year ($/kW)	Dispatch fees ($/kWh)	Expected cost at a 10% weighted probability of dispatch
Fast demand response	4,000	50	800	$4{,}000 \times \$50 + 4{,}000 \times 10\% \times \$800 = 200{,}000 + 320{,}000 = 520{,}000$
Day prior demand response	2,000	40	600	$2{,}000 \times \$40 + 2{,}000 \times 10\% \times \$600 = 80{,}000 + 120{,}000 = 200{,}000$
Expected cost of demand management				$720,000

In this example, the distributor's expected demand management costs for one year would be $720,000.

Example 1 provides a simple illustration under a hypothetical demand management contract. In practice, a distributor might structure a contract with another legal entity differently to this. However, a distributor should base any demand management contract under the Scheme on the capacity to manage network demand by a specified kVA per year.

A contract might specify payment on deliverables in various ways, including but not limited to:

- An availability payment of $/kVA per year;
- $/kVA per year x number of times used;
- $/kVA per year x hours of operation;
- $/kVA per year + MWh of demand management delivered.

6.2 Rationale for demand management proposal

While we consider the most practical and transparent way for a distributor to commit to deliverables is to specify these in a contract, we also recognise there may be instances where the distributor would not have a contract with another legal entity. Specifically, a distributor might provide the demand management component of an eligible project in-house if doing so is both:

- permitted under the distribution ring-fencing guideline and any other relevant laws, rules and regulatory requirements; and
- maximises the expected net benefit of the preferred option.

If such a situation arises, we see value in allowing in-house projects under the Scheme, whilst still encouraging the distributor to make a transparent commitment. Recognising that a distributor cannot enter a contract with itself, in these situations, we would require the distributor to provide information equivalent to a contract with another legal entity. For instance, this documentation must include a specified kVA per year of demand that a distributor can either directly or indirectly modify, as well as its expected cost of modifying (or having the capability to modify) that demand on the network.

We note, although the in-house option is an available approach, the distributor is still required to follow competitive testing as set out in clause 2.2.1 of the Scheme (and explained in section 5.1 above).

It is important for this documentation to carry weight, such that it constitutes a credible commitment. As such, we require the demand management proposal to receive approval from a delegate of the chief executive officer (CEO) of the distributor. Moreover, this approval must include a declaration by the delegate of the CEO that he or she has a reasonable basis for being of the view that the estimated costs in its demand management proposal are efficient. It must declare that the distributor calculated these cost estimates using a consistent approach to what the distributor would typically apply in estimating a project's costs shortly before that project's commissioning date. The delegate of the CEO should have a reasonable basis for being of the view that the distributor will likely incur the costs set out in the demand management proposal within some reasonable bounds of uncertainty (such as those it would normally apply to projects of a similar nature soon before the project commissioning date).

As set out in clause 2.2.2(1)(b) of the Scheme, without a demand management proposal compliant with the Scheme, an in-house option will not be recognised as a committed project and would therefore be ineligible for project incentives.

7 Determining the project incentive

Clause 2.3 of the Scheme specifies that when a distributor commits to an eligible project, it must calculate the incentive that project can accrue (the project incentive). The distributor must calculate the project incentive at the project commitment date (time *t*).

The project incentive cannot exceed the lower of the two values:

- As long as it is no lower than zero, the expected present value at time *t* of the project's demand management costs, less the total subsidies provided towards the demand management component of the project, multiplied by the cost multiplier $d_1 = 50\%$.[73] These expected demand management costs must be consistent with:
  - The costs of the demand management solution in the distributor's demand management contract or proposal.
  - The distributor's reasonable expectation of the frequency and duration on which it will call on or utilise its capability to influence or control demand under the demand management contract or proposal. That is, the distributor would need to determine probabilistically the demand it expects to influence or control when calculating the project's expected demand management costs.
- The expected present value at time *t* of the project's net benefit to all those who produce, consume and transport electricity in the relevant market (the net benefit constraint). A distributor must apply a cost–benefit analysis to calculate the project's expected net benefit by relative to the 'base case' where:
  - the distributor does not implement a credible option; or
  - only if the identified need is for reliability corrective action, the credible option that has the second highest expected net benefit.

The following sections explain why the Scheme requires distributors to calculate project incentives this way. Specifically, we explain why project incentives are to be:

- Based on demand management costs alone, rather than on the total cost of the non-network option.
- Based on expected, rather than actual demand management expenditure.
- Recovered from the distributor if the project incentive was originally based on expected costs that never occur because the distributor terminated its committed project before the committed end date.

[73] For avoidance of doubt, total subsidies in this context only include subsidies directly provided to the distributor in connection with the demand management component of the committed project. This does not include any subsidies directly delivered to other parties in providing the demand management component of that project.

- Net of any subsidies provided directly towards the demand management component of the project.
- No higher than the expected net benefit of that project (that is, be subject to a 'net benefit constraint').

7.1 Why demand management costs?

Since a non-network option under the NER can contain a network component, it is important for us to base the project incentive on the costs relating to demand management alone. A non-network option relating to demand management could contain a demand management component that constitutes a proportion of the project's total costs.

For instance, table 3 includes information about a non-network option assessed under a RIT–D. This non-network option included a one-year non-network support component costing $0.35 million, combined with a deferred network augmentation component costing $4.69 million. If a distributor undertook this project under the Scheme, we would only base the project incentive on the non-network component relating to demand management—which would be $0.175 million.

Table 3: Example of setting a project incentive for United Energy's Notting Hill option 2 (under base demand growth)

Value estimated for 'option 2'	$m, present value
Expected non-network costs (demand management component)	0.35
Expected network costs	4.69
Expected total costs	5.04
Expected net economic benefit	8.67
Project incentive	$0.35 \times 50\% = 0.175$

Source: United Energy, *Final project assessment report: Notting Hill supply area*, 14 December 2016, p. 39.

7.2 Why expected costs?

Consistent with the draft Scheme, we will base project incentives on expected costs. That is, distributors will receive incentives once they commit demand management expenditure (ex-ante), as opposed to when they incur that expenditure (ex-post). Ex-ante expenditure (or 'expected costs') reflects an ex-ante probabilistic assessment of what distributors expect will be their efficient demand management costs.

The Scheme provides project incentives on ex-ante expenditure because, relative to an ex-post approach, an ex-ante framework:

- Is more consistent with network planning, which takes place on a forward-looking basis and is based on a probabilistic assessment of future outcomes. That is, distributors make investment decisions based on expected costs and benefits.

- Is more consistent with incentive regulation, where we base distributors' allowed revenues on ex-ante assessments of efficient costs.
- Would have a lower administrative burden, which was supported by the discussion during the Feedback Forum. We also observed this when we were developing the draft Scheme.[74] When considering example projects, we formed the view that the administrative burden of ex-post review, particularly for projects that extend over a significant period, would be high. Some example projects that we identified could run for up to 25 years. Even if we were to limit the timeframe for providing ex-post incentives to a set number of regulatory control periods, it is unclear how best to identify and limit the periods.
- Would provide distributors with a more certain incentive given factors outside their control. An ex-post approach would provide weaker incentives when lower than expected demand drove lower dispatch costs. By avoiding this, an ex-ante approach would better reward option value when a distributor is unable to exercise its option. Ex-ante incentives also give distributors greater certainty about the size of their return. This is important, given many stakeholders have consistently supported a regulatory framework that encourages investment in demand management, given the developing nature of this market.

It is worth noting that some stakeholders at the Feedback Forum preferred an ex-post incentive approach because they would be more likely to reach the total incentive cap in any year under the ex-ante approach.[75] We consider these views go to the size of the total incentive cap as opposed to the validity of the ex-ante approach. For a discussion on why and how we set the total incentive cap, see section 9.1 of this explanatory statement.

7.3 What if distributors terminate committed projects early?

Based on stakeholder submissions on the draft Scheme and discussions at the Feedback Forum, we have made a provision in clause 2.4(7) of the Scheme to better encourage distributors to deliver the demand management projects they commit. When a distributor commits a project under the Scheme, it accrues project incentives based on its expected demand management costs over the length of that committed project, marked by a project end-date. If a distributor terminates a committed project before its project end-date, clause 2.4(7)(b) of the Scheme allows us to recover the project incentives paid on expected demand management costs over the time that the commitment was broken. We would expect distributors to specify the project end-date in its demand management contract or demand management proposal.

[74] See the discussion in AER, *Explanatory statement: Draft demand management incentive scheme*, August 2017, pp. 52–3.

[75] AER, *Demand management feedback forum discussion summary*, 8 November 2017.

Table 4 provides an illustrative example of what would happen under the Scheme if a distributor terminated a committed project early. In this example, a distributor commits to a five year project, but terminates it after year three. In this situation, we would recover the project incentives we had provided on expected costs for years four and five, since the project did not occur over these years. For clarity, the project incentives we recover will be independent of whether there were project overspends or underspends in years when the project was ongoing, as the Scheme provides ex-ante incentives. Incentive recovery only occurs due to early termination of projects.

Table 4: Example of early termination of a committed project ($mil, year 1)

Year	1	2	3	4	5
Expected demand management costs (based on the project commitment)	2	2	2	2	2
Project incentive accrued on ex-ante costs*	$2 \times 5\ years \times 50\% = 5$	0	0	0	0
Actual costs (project terminated after year 3)	1	3	3	0	0
Accrued incentive to return (based on early termination)	0	0	0	$2 \times 2\ years \times 50\% = 2$	0

* Assuming $d_v = 50\%$,, there are no subsidies on the committed project, and the project incentive cap does not bind.

We have also included clause 2.6(2) in the Scheme so electricity consumers only reward projects that have commenced. Under this clause, we can only include a committed project's incentive in the distributor's total annual revenue once the distributor has undertaken, or has committed to undertake expenditure as part of that committed project.[76] Section 9.3 of this explanatory statement explains this clause further, which will take effect if there are project delays or cancellations that were unanticipated at the time the distributor committed the project. We have connected clause 2.6(2) and 2.4(7) under the Scheme, which both serve a similar compliance function.

We added clause 2.4(7) to the Scheme after considering stakeholder submissions on the draft Scheme and discussing this with them at the Feedback Forum,[77] because we consider it:

- Balances the different views stakeholders put forward at the Feedback Forum. For instance, stakeholders had divided views on whether we should provide incentives ex-ante or ex-post.[78] Some stakeholders preferred us to complement the ex-ante

[76] See clause 2.6(2) of the Scheme.

[77] AER, *Presentation: Demand management feedback forum*, 8 November 2017, slide 13.

[78] AER, *Demand management feedback forum discussion summary*, 8 November 2017, pp. 1–2.

incentive mechanism in the draft Scheme with mechanisms that defer or claw-back incentives for projects that distributors delay or terminate early.[79] For instance, ISF submitted that:[80]

> the Draft Scheme does not include provision to recover any DM incentives for committed projects that do not proceed. Nor does the Draft Scheme provide for recovering DM incentives for projects which fall short of planned expenditure or customer benefits. This creates potential for moral hazard, chronic underperformance of projects and inequitable treatment between distributors.

- Fairly shares risks between electricity consumers and distributors. Recovering incentives for expenditure that does not occur due to early project termination:
  - Still maintains a benefit of the ex-ante approach, where distributors receive the same incentive when lower than expected demand drives lower dispatch costs. It therefore protects distributors from risks that are largely outside their control and rewards them for the option value associated with demand management; and
  - Prevents the Scheme from unnecessarily transferring risks onto electricity consumers, where distributors have the capacity to manage those risks. Distributors only risk returning a portion of their ex-ante project incentives if they terminate a demand management contract early, or do not fulfil the time commitment in a demand management proposal. This protects electricity consumers from incentivising demand management expenditure that never occurred, due to a distributor's decision to terminate a project that it had previously committed to.
- Prevents the Scheme from rewarding projects when they are not occurring, and therefore increases the credibility of the Scheme and demand management solutions. If the Scheme unduly rewards activities that do not occur, this could have a negative impact on the reputation of demand management as an effective and efficient solution, and could hinder the Scheme Objective.

While this addition would marginally increase the complexity and potential administrative burden of the Scheme, we are satisfied the benefits would outweigh the costs as:

- The direct costs of returning the incentive would only occur when distributors do not completely fulfil their demand management contracts or demand management proposals. We consider these situations would rarely occur, if at all. If they do occur, we consider the benefits to electricity consumers would outweigh the administrative costs.

---

79 ISF voiced this view at the Feedback Forum, as well as in ISF, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017. MEU also implied a need to provide this protection in MEU, *Submission on draft demand management incentive scheme and innovation allowance mechanism*, 9 October 2017.

80 ISF, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017, p. 12.

- Other administrative costs would be associated with any additional effort distributors feel they need to avoid terminating committed projects. This might include putting greater effort into setting a project-end date that distributors consider they are likely to meet. We consider these costs would be minimal, and would also have the benefit of encouraging distributors to set achievable project commitments.

7.4 Why net of subsidies?

The final Scheme requires distributors to deduct subsidies they directly receive for committed projects from those projects' expected demand management costs, before calculating incentives on those costs. This addition aims to prevent electricity consumers from paying more than necessary to incentivise projects that would have otherwise occurred due to the benefits they received from government subsidies. Given this, we consider this addition would be in the long term interest of electricity consumers. When we discussed our proposal to include this addition at the Feedback Forum, there was a general understanding among stakeholders that distributors should not receive incentives on costs recovered through government subsidies.[81]

When we raised this proposal at the Feedback Forum, stakeholders provided several suggestions, which we have considered in developing the Scheme. For instance,[82] one party suggested that, since subsidies would reduce the overall cost of a project, we should consider these as part of the net benefit analysis, rather than at the incentive calculation stage. In our view, considering subsidies at the net benefit analysis stage should not be in opposition to considering them at the incentive calculation stage. Under the Scheme, subsidies should always be a relevant consideration for the net benefit analysis, where distributors aim to maximise the net benefit of all those who produce, transport and consume electricity in the relevant market.[83] Given any subsidy provided from outside the relevant market (such as from a government body) is a benefit to the relevant market, this would increase the net benefit of the option.

Also, there were contrasting views at the Feedback Forum on whether we should deduct subsidies that other parties receive to provide distributors with demand management services from incentive payments under the Scheme. Some stakeholders objected to this given third parties, rather than the distributors, would receive the subsidies. At the Feedback Forum, we indicated that we would consider also deducting subsidies that other parties receive to provide the distributor the demand management services under the committed project. After considering this option, we have formed the view that we should limit incentive deductions to subsidies directly provided to distributors. Distributors would already receive commensurately lower incentives to the extent that the other party uses the subsidy to charge the distributor less for its demand management services (since incentives are based on demand management

81 AER, *Demand management feedback forum discussion summary*, 8 November 2017, p. 2.

82 AER, *Demand management feedback forum discussion summary*, 8 November 2017, p. 2.

83 The relevant market being the National Electricity Market (NEM), or other relevant electricity market.

expenditure). To the extent other parties do not pass the subsidy onto distributors, the distributor would not benefit from the subsidy and the Scheme Objective might be better met if distributors still received project incentives under the Scheme.

7.5 The net benefit constraint

Under the Scheme, a project incentive cannot exceed the expected present value at time *t* of the project's net benefit to all those who produce, consume and transport electricity in the relevant market (the net benefit constraint). That is, although a project incentive is 50 per cent of its expected demand management costs, a constraint on this calculation applies so the project incentive cannot exceed the project's expected net economic benefit.

Distributors must estimate a project's net benefit relative to a 'base case' where:

- the distributor does not implement a credible option; or
- if the identified need is for reliability corrective action, the credible option with the second highest net benefit.

We have included a net benefit constraint because, in meeting the Scheme Objective and principles in the NER, our Scheme should operate to incentivise efficient projects that deliver net cost savings to retail customers.[84] So that the Scheme delivers ex-ante net cost savings to retail customers, a project incentive must be no higher than its expected net economic benefit across the relevant market. A distributor must calculate its project's net benefit relative to a 'base case' where it does not implement a credible option, or where it implements the credible option with the second highest net benefit (but only if the identified need is for reliability corrective action).[85] This allows for a practical application of the net benefit constraint, that adjusts for the fact that reliability corrective action projects need not have a positive net benefit against a 'do nothing' base case.

The illustrative example in table 5 highlights what effect a binding net benefit constraint could have on a project incentive. In the hypothetical scenario presented in table 5, the net benefit constraint binds such that the project incentive is set to the expected net benefit ($2.5 million) rather than 50 per cent of the project's demand management costs ($5 million). If the Scheme did not feature a net benefit constraint, the project incentive would have been set to $5 million, which would have produced an expected net cost to the retail customers of $2.5 million. As such, the net benefit constraint helps the Scheme satisfy the principle in the NER to deliver net cost savings to retail customers.

[84] See NER cl. 6.6.3(b) for the relevant objective, and NER cl. 6.6.3(c)(2) for the relevant principle.

[85] The draft Scheme specified that for reliability projects, distributors would use the preferred network option as the base case. We have since changed this to the 'credible option with the second highest net benefit'. This recognises that there may be situations where the most credible options that the distributor is comparing are only comparing non-network options.

Table 5: Illustrative example of binding net benefit constraint in setting the project incentive

Value estimated	$ million
Expected demand management costs	10.0
Expected net economic benefit (against the base case)	2.5
Project incentive	$\min\{10 \times 50\% = 5;\ 2.5\} = 2.5$

8 Compliance reporting

Clause 2.4 of the Scheme specifies that each regulatory year, a distributor will submit a demand management compliance report to us no later than four months after that regulatory year ends. This aligns with the submission of the information in response to the distributor's regular Regulatory Information Notice (RIN). The report produced should form part of the information submitted during the RIN process, and be reviewed as per the assurance requirements of the RIN. Clause 2.4 of the Scheme also lists the project-specific data distributors must report.

Under Part A of the compliance report, distributors must include data pertaining to their committed projects under the Scheme that were incurring expenditure in the past regulatory year. Data must include sufficient information for us to verify what outcomes were achieved due to that expenditure. Specifically, this includes listing the committed demand management projects and reporting the kVA per year of demand management delivered under committed projects. It also includes reporting on the benefits the distributor estimates has resulted from the demand management.

Under Part B of the compliance report, the distributor must include data on any eligible project it identified as a preferred option in the past regulatory year, including:

- The total financial incentive the distributor accrued, to assist us in validating the total financial incentive. Distributors should base the total financial incentive it accrued on:
    - the project incentives it accrued from the projects it committed that year; and
    - if applicable, any adjustments for terminating committed projects earlier than the end date it assumed when calculating expected demand management costs for the net benefit calculation. This will help us give effect to clause 2.4(7)(b) of the Scheme, which we added to address concerns raised by ISF and MEU.[86] We consider this addition better balances risk between consumers and distributors under the ex-ante incentive accrual approach.[87]
- Listing the identified eligible projects, as well as their expected costs and benefits. This information allows us to understand the potential types of eligible projects under the Scheme and the project incentives.
- Information on the responses that constituted 'credible options' that the distributor received to either its RIT–D or its request for demand management proposals under the minimum project evaluation requirements.[88] This information should

---

86 ISF, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017; MEU, *Submission on draft demand management incentive scheme and innovation allowance mechanism*, 9 October 2017.

87 For a description of this ex-ante approach, see section 7.2 of this explanatory statement.

88 This is where a credible option has the meaning given in clause 5.15.2(a) of the NER. That is, an option (or group of options) that addresses the identified need, is (or are) commercially and technically feasible, and can be

include a description of these proposed projects, as well as their proposed costs, deliverables and estimated net benefits. This will assist us in verifying whether distributors have tested the demand management services market in selecting the preferred option. It also helps us understand any differing results between distributors' demand side engagement activities and whether these results are likely driven by differing procurement practices, geographic markets or unique network needs.

- Identify the party/parties it proposes to contract with, or whether it proposes to provide the demand management component in-house. Identifying this should help us understand the state of the market for demand management services, and the outcomes of the distributors' competitive testing.
- The expected costs of delivering demand management under the non-network option, as applied in its cost–benefit analysis to determine the preferred option. A distributor must include the kVA per year of network demand that it can call upon, influence or control and expects to dispatch, influence or control, based on its probabilistic assessment. This information should assist us in:
  - Understanding the assumptions distributors apply in assessing demand management options in their cost–benefit analyses.
  - Projecting the Scheme's impact in subsequent financial years.

8.1 AER use of compliance report

Within eight months of the completion of the regulatory year to which that compliance report pertains, we will validate the pass through of the total financial incentive through the annual pricing proposal. Not necessarily at the same time, we will also publish a performance report that compares how different distributors have applied the Scheme.[89]

The annual performance report will assist us in identifying if there is merit in altering the magnitude of the cost multiplier in a future version of the Scheme. For instance, when amending the Scheme, we may consider:

- Reducing the cost multiplier where there are compliance concerns with distributors' use of the Scheme. Compliance concerns might include (but are not limited to) distributors inflating expected costs, reporting misleading information, not complying with the ring-fencing guideline, and not complying with the minimum project evaluation requirements when relevant.
- Adjusting the cost multiplier where there is evidence that doing so might better incentivise distributors to undertake efficient non-network options relating to

implemented in sufficient time to meet the identified need, and is (or are) identified as a credible option in accordance with paragraphs NER 5.15.2(b) or (d) (as relevant).

89 Ideally, we would publish one performance report per year for both distributors operating on calendar years and financial years. Given this, we may not publish a performance report at the same time we validate the pass through of the total financial incentive.

demand management. Such evidence might arise following market or regulatory changes or if our decision to set a cost multiplier of 50 per cent proves either generous or conservative.

The annual performance report should also provide transparency to enhance understanding around how different distributors are:

- Estimating, accounting for and realising the benefits of demand management.
- Procuring or providing demand management as an input for distribution network services, and subsequently accruing financial incentives under the Scheme.
- Proactively tendering for another legal entity to provide demand management services.
- Undertaking demand management in-house in a manner that is compliant with the ring-fencing guideline.
- Utilising demand management in different ways to meet their unique network needs.

9 Accruing and applying the financial incentive

Clauses 2.5–2.6 of the Scheme describe how project incentives accrue to form a total financial incentive for a regulatory year. These clauses set out that:

- There is a cap on the total financial incentive accrued to a distributor in any regulatory year.
- This cap equals 1.0 per cent of the distributor's annual smoothed revenue requirement (AR) for that regulatory year.
- We incorporate the total financial incentive into a distributor's total annual revenue with a two-year lag. Clause 2.6(2) of the Scheme specifies that the committed project's incentive is only payable at this point if the distributor has already undertaken, or has committed to undertake expenditure as part of the committed project.

9.1 Total financial incentive capped annually

The Scheme caps the total financial incentive a distributor can receive in any regulatory year to a percentage of its AR for that regulatory year.

We have decided to include a cap to protect retail customers from the possibility of bearing costs under the Scheme that are unexpectedly high.[90] There is value in providing such protection, which can limit the potential risk of:

- Setting an incentive that is too high-powered, which may arise given we adopt a simpler and less 'precise' approach. For instance, the Scheme proposes a uniform incentive (a demand management cost multiplier of 50 per cent),[91] which we consider a reasonable magnitude for projects on average (but not necessarily at an individual-project level).[92]
- The initial design containing unintended loopholes or challenges for enforcing compliance. Such design limitations could lead the Scheme to unintentionally incentivise inefficient projects and/or projects that do not deliver net cost savings to retail customers. For instance, ECA's support for providing financial incentives under the Scheme is contingent on distributors engaging the support of their consumers for proposed demand management activities, and providing clear and accessible information about these activities and their impacts on the need for other network investments.[93] While the Scheme should hopefully support these

[90] Consistent with NER cl. 6.6.3(c)(4)(i).

[91] Subject to the net benefit constraint.

[92] It is worth noting that the simpler approach is valuable given the more 'scientific' approach would come at a prohibitively costly administrative burden. This is because a more scientific approach would likely require us to set specific incentives for individual projects. These incentives would reflect the project's benefits to retail customers that the distributor would not otherwise capture.

[93] ECA, *Submission to the AER's development of a Demand Management Incentive Scheme and Innovation Allowance*, June 2017, p. 3.

activities, there are always risks in designing and implementing a new incentive scheme or regulatory mechanism.

In response to the draft Scheme, some stakeholders supported the cap, which would apply on an annual basis.[94] However, Ausgrid, ENA and Energy Queensland submitted that since the cap applies on an annual basis, we should complement this with a carryover mechanism or a smoothing mechanism.[95]

While we understand the appeal of a smoothing mechanism, our intent for setting the total incentive cap on annual basis was to encourage the Scheme to take effect quickly. This will also prevent the Scheme from causing price volatility as capping the incentive to 1.0% of allowed revenue would prevent price shocks in any year. In contrast, if the total incentive cap was set for an entire regulatory control period using a carryover mechanism, but without a revenue spreading mechanism, this could plausibly result in price shocks if many large projects were committed in one particular year within that period.

While having an annual incentive cap limits the size of the incentive available in any one year, we are satisfied that the total incentive cap is sufficiently large to avoid this concern. Section 9.2 explains why we consider the magnitude of the total financial incentive cap is reasonable.

9.2 Magnitude of total financial incentive cap

We consider 1.0 per cent of AR is a reasonable cap to place in the first version of the Scheme as this:

- Is similar to the cap used under the annual network capability incentive allowance. This cannot be greater than 1.5 per cent of the average annual maximum allowed revenue of a transmission network service provider over the regulatory control period.[96]
- As illustrated in table 6, allows distributors to receive total financial incentives on their efficient demand management costs of up to approximately $1.5–16.2 million per year, depending on the size of the distributor. Across the NEM, this represents a cap of approximately $100 million in incentives per year. Since project incentives under the Scheme can be no higher than 50 per cent of the expected demand management expenditure, reaching this cap across the NEM would require distributors committing at least $200 million worth of demand management expenditure that year.

---

94 SACOSS, *Submission on draft demand management incentive scheme, innovation allowance mechanism and proposed early application rule change*, 28 September 2017. This was implicitly supported by MEU, Submission on draft demand management incentive scheme and innovation allowance mechanism, 9 October 2017.

95 Ausgrid, *Submission on draft demand management incentive scheme and innovation allowance mechanism*, 12 October 2017; ENA, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017; EQ, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 17 October 2017.

96 AER, STPIS version 5 (corrected), October 2015, clause 5.3(a).

Table 6: One per cent allowed revenue in recent year ($ mil)[97]

Distributor	Total incentive cap ($mil, nom)
ActewAGL Distribution*	1.50
Ausgrid*	16.18
AusNet Distribution	6.46
CitiPower	3.08
Endeavour Energy	7.87
Energex	14.18
Ergon Energy	13.37
Essential Energy	10.08
Jemena Electricity	2.70
Powercor Australia	6.46
SA Power Networks	8.02
TasNetworks Distribution	2.42
United Energy	4.49
Total	**96.80**

* Includes dual-function assets.

In response to the draft Scheme, while some stakeholders supported our proposed total incentive cap,[98] others questioned its magnitude.[99] In our view, a total incentive cap of 1.0 per cent of AR is:

- Substantial enough to incentivise distributors to actively explore demand management opportunities, where efficient to do so, as a competitive solution against supply-side options. We do not consider this would necessarily limit demand management expenditure below its economic potential, as EEC suggested.[100] This is because the Scheme does not prevent or penalise distributors from exceeding the cap. Rather, expenditure above the cap simply foregoes an

---

97 Figures based on AER final decisions before appeals to the Australian Competition Tribunal.

98 SACOSS, *Submission on draft demand management incentive scheme, innovation allowance mechanism and proposed early application rule change*, 28 September 2017. This was implicitly supported by MEU, Submission on draft demand management incentive scheme and innovation allowance mechanism, 9 October 2017.

99 Citipower, Powercor and United Energy, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 11 October 2017 suggested increasing or removing the total incentive cap, SAPN, *Submission on the draft demand management incentive scheme, innovation allowance mechanism and proposed early application rule change*, 12 October 2017 suggested we increase the cap to 1.5% of AR to better align with the network capability incentive allowance.

100 EEC, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, October 2017.

additional benefit under the Scheme. To the extent that expenditure beyond the cap is efficient, the distributor would still benefit from these projects under the incentive regulation framework.

- Modest enough to protect retail customers from bearing costs under the Scheme that are unexpectedly high, considering the long term benefits that the Scheme will provide to them.[101] In their submissions to the draft Scheme, CitiPower, Powercor, United Energy and SA Power Networks (SAPN) suggested the cap need not be so modest, given the net benefit constraint would be a sufficient safeguard for the Scheme to deliver value to electricity consumers.[102] While the net benefit constraint is an important safeguard, we also recognise that net benefit calculations have elements of complexity and subjectivity to them (see section 4.1). Given this, we consider there is value in maintaining a cap, at least for the first version of the Scheme.
- Unlikely to be too restrictive or conservative, as ISF has suggested.[103] For instance, there is no pressing need to consider increasing the 1.0 per cent cap given distributors will need to undertake a notably larger amount of efficient demand management before they reach this cap. That said, there may be merit in revaluating the 1.0 per cent cap after observing the Scheme's impact on encouraging network-level demand management.

9.3 Applying total financial incentive with two year lag

Clause 2.6 of the Scheme describes our process for including the total financial incentive in the distributor's total annual revenue. Under this process, we apply the total financial incentive with a two year lag. This lag allows us to pragmatically incorporate the total financial incentive into a distributor's total annual revenue via its annual pricing proposal process.[104]

We have also included clause 2.6(2) in the Scheme specifying that we cannot include a committed project's incentive in the distributor's total annual revenue until the distributor has already undertaken, or has committed to undertake expenditure as part of that committed project.[105] By 'committed to undertake expenditure', we mean that the distributor has a legal obligation (for example, to the supplier of the relevant

---

[101] Consistent with NER cl. 6.6.3(c)(4)(i).

[102] Citipower, Powercor and United Energy, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 11 October 2017; SAPN, *Submission on the draft demand management incentive scheme, innovation allowance mechanism and proposed early application rule change*, 12 October 2017.

[103] ISF, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017.

[104] We currently apply a similar lag in the demand management innovation allowance, where we deduct (add) the final carryover amount from the previous regulatory control period from (to) the total annual revenue in the second regulatory year of the subsequent regulatory control period. For example, see AER, *Final decision–Demand management incentive scheme: Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15*, April 2009 p. 23.

[105] See clause 2.6(2) of the Scheme.

demand management solution) that requires or is likely to require it to make a payment.

The ISF suggested adding this 'maximum lead time' clause in its submission to the draft Scheme.[106] We agreed with the ISF's reasoning, that a maximum lead time clause would provide a sensible in-built compliance measure that will help the Scheme deliver value to electricity consumers. Specifically, we do not consider it would be in the interest of electricity consumers to reward projects that are yet to commence.

We expect the maximum lead time clause will take effect if there are project delays that were unanticipated at the time the distributor committed the project. If such delays result in the project eventually being cancelled, we would use this clause in connection with clause 2.4(7)(a) to prevent consumers for providing incentives for activities that did not occur. If delays do not result in the cancellation of the project, this clause would result in the distributor receiving the incentive later, reflecting the project's later start date.

It is worth noting that, based on stakeholders comments on the draft Scheme and at the Feedback Forum, we included clause 2.4(7) in the Scheme, which complements the maximum lead time clause. If a distributor terminates a committed project before its project end-date, clause 2.4(7)(b) of the Scheme allows us to recover the project incentives paid on expected demand management costs over the time that the commitment was broken. Section 7.3 explains this addition further.

Figure 7, which also appears in the Scheme, summarises the process for applying the total financial incentive. This process requires a two year time lag from when the demand management expenditure occurs so that:

- The distributor can submit compliance information to us four months after that regulatory year.
- We can verify the total financial incentive to be passed through to consumers four months after receiving the compliance information.[107]
- The distributor incorporates the total financial incentive into its pricing proposal once month after we have verified its total financial incentive.
- The distribution use of system charges come into effect three months after we receive the distributor's pricing proposal — that is, at the start of the next regulatory year.

[106] ISF, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017.

[107] The draft Scheme specified a five month period. We reduced this to four months to provide distributors with time to incorporate this into their pricing proposals. The ISF supported this change in *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017.

Figure 7: Process for passing through the total financial incentive

$t - 2\ years$

Distributor accrues the total financial incentive for year $t - 2$.

$t - 8\ months$

Distributor submits compliance report to AER under the Scheme for year $t - 2$.

$t - 4\ months$

AER determines the total financial incentive for the year $t - 2$.

$t - 3\ months$

Distributor submits pricing proposal for year t to AER, which includes, as part of its total annual revenue, the total financial incentive approved or determined by AER for year $t - 2$.

$year\ t$

Distributor recovers total financial incentive for year $t - 2$ from consumers in year t via distribution use of system charges.

10 Elements considered for the Scheme

Our explanatory statement to the draft Scheme summarised how the draft Scheme incorporated the different incentive mechanisms we consulted on as potential options in our Consultation Paper. Stakeholders broadly accepted our approach to these different mechanisms, which is summarised in section 9 of the draft Scheme's explanatory statement.[108] As such, we have limited this section to discuss our consideration on:

- Providing targets for demand management deployment, which the Energy Efficiency Council (EEC) submitted warranted further consideration.
- Removing disincentives to undertake demand management.

10.1 Targets for demand management deployment

In our Consultation Paper, we noted a potential option might entail rewarding distributors for achieving pre-determined demand management targets based on identified constraints at the planning stage.[109] However, we have not based the Scheme on demand management targets. This is because:

- Demand management targets would be difficult to implement as these would require:
    - Setting baseline peak demand targets.
    - Making annual adjustments for factors like weather, energy efficiency and major plant closures to determine whether a distributor's demand management activities had driven the observed demand reductions.
- Failure to meet the targets would not result in financial penalties under the Scheme, given NER clause 6.6.3(c)(5) requires that penalties should not be imposed on distributors under any Scheme. While failure to meet targets could impose a reputational penalty, we consider this would likely add little to what our annual performance report would achieve, as discussed in section 8.1.
- Could not, in isolation, achieve the Scheme Objective to incentivise distributors to undertake efficient non-network options relating to demand management. Achieving this would require us to set a target level of demand management that was 'efficient', which would be difficult for us to set.
- In our view, the costs would outweigh the benefits, even if we adopted EEC's suggestion to set minimum targets requiring every distributor undertake some level

108 AER, *Explanatory statement: Draft demand management incentive scheme*, August 2017, pp. 54–58.

109 AER, *Consultation paper: Demand management incentive scheme and innovation allowance mechanism*, January 2017, p. 42.

of demand management, with the expectation that distributors should invest well above that level.[110] We have formed this view because it is:

  - Unclear how we could 'require' distributors to meet minimum targets under 6.6.3 or the NER, particularly with our inability to impose penalties.
  - Plausible that for some distributors, in some years, there will be no efficient demand management opportunities—particularly where they have previously overinvested in network capacity.
  - Questionable what benefits targets would achieve if we set them with the expectation that all distributors would invest well above that level, particularly if we will publish annual performance reports in any case.

While some stakeholders supported demand management targets in their submissions to our Consultation Paper,[111] the majority of these submissions emphasised the difficulties with implementing a target-based Scheme. We generally accept the following submissions:

- Origin Energy submitted that targets could create perverse investment signals. It preferred a market-driven investment environment for providing long-term efficient price signals and investment. United Energy also noted that targets would create distortions that would undermine the intent of encouraging efficient demand management.
- AusNet Services and Jemena noted the risk or inefficiency if the target level is poorly set in either direction. Endeavour Energy, Ergon Energy, SAPN and ENA submitted that broad-based targets could incentivise distributors to implement demand management where inefficient. CitiPower and Powercor noted that the risk of consumers bearing the cost of inefficient demand management would be particularly high in the current low demand growth environment.
- GreenSync highlighted the complexity of this approach. Baseline targets would require us to determine the MW or MWh targets, which would require significant consultation with the market and modelling of future outcomes. AusNet Services, Jemena and United Energy also saw demand management targets as creating unnecessary complexity or subjectivity.
- Ausgrid and ENA recognised that while we would base a target on a distributor's requirements at a point in time, network planning is a continuous process. Ausnet

---

110 EEC, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, October 2017.

111 Some stakeholders supported this option in their submissions to our Consultation Paper, including TEC and the Energy Efficiency Council. While AGL supported targets, it also supported scrutiny for underperformance, which would be challenging under the rules that do not permit penalties. While Public Interest Advocacy Centre (PIAC) supported supplementary targets, it was unclear whether these would address network constraints, particularly in NSW where there is spare capacity. It also noted that targets would require departing internal and external demand drivers.

Services noted that targets would not align with approaches to develop efficient network development plans.

- Energex submitted that targets would fail to recognise the full range of demand management projects.

10.2 Removing demand management disincentives

In our January 2017 demand management consultation paper, we considered exempting demand management projects associated with the Scheme from other regulatory instruments. In particular, we consider providing exemptions from the service target performance incentive scheme (STPIS), the efficiency benefit sharing scheme (EBSS) and the capital expenditure sharing scheme (CESS).

We did not include demand-management related exemptions in the draft Scheme, and have maintained this position in the final Scheme. This is for the following reasons:

- STPIS exemptions may also expose consumers to more risk, by placing the risk of project unreliability on them. Since distributors are better placed to mitigate these risks, it is preferable that they should bear the costs associated with those risks. Moreover, exempting demand management projects from the STPIS may serve to increase a perception that demand management projects are less reliable than capex alternatives, which would be contrary to the aims of the Scheme.
- The symmetrical operation of incentives under the CESS and EBSS should balance out any negative impacts that distributors may experience under any one of these schemes. For instance, as distributors spend more on opex, they may exceed their targets under the EBSS and receive a smaller incentive or higher penalty as a result. However, since the Scheme only incentivises efficient demand management projects, we would expect that reductions in capex gained from project deferral or avoidance would exceed any increase in opex under the demand management project. In this scenario, benefits under the CESS would outweigh any detriment provided under the EBSS.

Stakeholders generally accepted this position we put forward to support the draft Scheme. SAPN accepted that opex on committed projects under the Scheme would form part of the opex building block, but asked us to clarify whether we would also include project incentives in the opex building block.[112] We clarify that project incentives under the Scheme do not represent opex and would therefore sit outside the opex building block and be excluded from the EBSS. It is also worth noting that funding under the Mechanism will also sit outside the opex building block.

112 SAPN, *Submission on the draft demand management incentive scheme, innovation allowance mechanism and proposed early application rule change*, 12 October 2017.

A Calculating net benefits

The net benefit calculation aims to identify the preferred option, which is the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the relevant market. In this calculation, the net economic benefit equals the market benefits less costs.

Distributors can refer to the RIT–D and its application guidelines for guidance in performing net benefit calculations.[113] In particular, Attachment A of the RIT–D application guidelines provides specific guidance and worked examples on valuing classes of market benefits.[114] This guidance includes a worked example of quantifying changes in costs to other parties as a market benefit.[115]

A number of eligible projects under the Scheme will be subject to the RIT–D in the first instance, and would therefore undergo a net benefit calculation independent of the Scheme. However, there will also be projects eligible under the Scheme that fall under the RIT–D threshold.[116] When performing net benefit calculations for non-RIT–D projects, there may be value in distributors applying simplified approaches to quantifying particular costs or benefits where appropriate and reasonable.

A.1 Guidance on net benefit tests for small projects

In its submission on the draft Scheme, the ISF suggested guidance we could provide to assist distributors in performing a simple net benefit test for smaller projects that fall outside of the RIT–D threshold under the Scheme.[117] We have reviewed the ISF's suggested guidance, and consider it represents a reasonable evaluation process for smaller projects under the Scheme, that are not subject to the RIT–D.

Where a distributor would calculate all costs in present value terms, a simple process for applying the net benefit test under the Scheme could entail identifying a preferred option by:

1. Using the expected value of customer energy at risk as a proxy for expected costs under the 'do-nothing base case'. A distributor could estimate customer energy at risk by:
   (a) Comparing current and expected network capacity to forecast load;

---

[113] For the RIT–D and its application guidelines, see: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/regulatory-investment-test-for-distribution-rit-d-and-application-guidelines.

[114] AER, *Better regulation: RIT–D application guidelines*, 23 August 2013, pp. 55–64.

[115] AER, *Better regulation: RIT–D application guidelines*, 23 August 2013 pp. 60–61.

[116] For example, under NER 5.17.3(a)(2), if the estimated capital costs of the most expensive potential credible option fall under $5 million, the project is exempt from the RIT–D.

[117] ISF, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017, p. 10.

(b) Estimating expected customer energy at risk using the expected probability of energy shortfall; and

(c) Multiplying expected customer energy at risk by the value of customer reliability.

2. As an optional step, developing and costing an initial preferred option. This option would be a credible option if its expected costs are less than those calculated in step 1.
3. Testing the market by requesting demand management solutions.[118] Any option put forward would be a credible option if its expected costs are less than those calculated under step 1.
4. Calculating the expected net costs of credible options. This entails subtracting from the expected costs of any credible option identified in steps 2 and 3, any relevant option value and expected customer savings via changes in the net costs of generation and transmission networks.
5. Identifying the preferred option as the option with the lowest net cost from step 4.
6. Deriving the net benefit by subtracting the costs calculated under step 1 from the net cost of the preferred option under step 5.

A.2 Option value

We recognise that option value is an economic benefit that can be especially difficult to estimate due to its complexity and reliance on assumptions. Various stakeholders have explicitly recognised these difficulties.[119] For example, SAPN only supported internalising option value if the calculation could be simple.[120] Also, Endeavour Energy requested we provide guidance if we were to internalise option value in the Scheme.[121]

In the explanatory statement to the draft Scheme, we sought stakeholder views on a method that Oakley Greenwood considered would be reasonable for approximating option value. We acknowledge Oakley Greenwood's suggestion to approximate option value reflects: [122]

- The level of uncertainty in the demand forecast, which reflects the probability of a demand scenario occurring that will cause a network constraint.

---

[118] While a distributor could also test the market by running a RIT–D process, we envisage this simplified net benefit analyses would only apply to non-RIT–D projects.

[119] CitiPower and Powercor, *Re: Consultation Paper – Demand management incentive scheme and innovation allowance mechanism*, 24 February 2017; Endeavour Energy, *RE: AER Consultation Paper – Demand management incentive scheme and innovation allowance mechanism January 2017*, 24 February 2017; Ergon Energy, *Consultation Paper – Demand management incentive scheme and innovation allowance mechanism January 2017*, 24 February 2017.

[120] SA Power Networks, *Demand management incentive scheme and innovation allowance*, 24 February 2017.

[121] Endeavour Energy, *RE: AER Consultation Paper – Demand management incentive scheme and innovation allowance mechanism January 2017*, 24 February 2017.

[122] For more details on Oakley Greenwood's methodology, see Oakley Greenwood, *Advice on the DMIS incentive prepared for AER*, 23 June 2017.

- The impact demand uncertainty has on a distributor's capex program. This reflects the difference in the cost of the options required under different demand scenario outcomes.

We recognise that option value is a key benefit that demand management options can provide. Many stakeholders also share this view.[123] We received little input on the suggested method. SAPN submitted that while it welcomed the analysis by Oakley Greenwood, it considered a non-prescriptive approach would be prudent on this theoretical and technical aspect of project evaluation.[124]

In principle, we support stakeholders using reasonable approaches to approximate option value for small projects, where using costlier methods is unviable.

---

[123] AEMO, *Demand management incentive scheme and innovation allowance mechanism*, 24 February 2017; AGL, *Demand management incentive scheme and innovation allowance mechanism – Consultation paper*, 27 February 2017; CitiPower and Powercor, *Re: Consultation Paper – Demand management incentive scheme and innovation allowance mechanism*, 24 February 2017; Energy Efficiency Council, *Re. Consultation Paper - Demand management incentive scheme and innovation allowance mechanism*, 20 March 2017; ISF, *Submission to AER, Response to consultation paper: Demand management incentive scheme & innovation allowance mechanism*, 27 February 2017.

[124] SAPN, *Submission on the draft demand management incentive scheme, innovation allowance mechanism and proposed early application rule change*, 12 October 2017.

B Worked examples — Calculating incentives under the Scheme

B.1 Switchgear worked example

We have based this worked example on information provided to us by Ausgrid. It represents a typical example of how Ausgrid would assess a demand management project, but the numbers used are not based on a real identified need.

We also included this worked example in the explanatory statement to the draft Scheme, and it is for illustrative purposes only. This is a relatively simple worked example to demonstrate the basic functioning of the Scheme. The distributor has already quantified the net benefit delivered by the option, and so this example does not deal with that stage of the process. We have also assumed that the requirements for identifying and committing projects to ensure efficiency under the Scheme have been followed.

In this example, the distributor has identified that the switchgear in a zone substation needs to be retired or replaced. The failure of this asset would result in the loss of power to customers. In response, the distributor has identified that replacement of the asset is a credible option.

In this example, the distributor has discounted using a real rate of return, which is consistent with the real cashflows used in its modelling. In table 7 and table 8, cash flows are presented in 2018 dollars and the NPV calculations employ a discount rate of 4.66 per cent. The costs and benefits presented in table 7 and table 8 are calculated with reference to a base case of doing nothing to address the identified need.

Table 7: Network preferred option ($2018, '000)

Year	2018	2019	2020	2021	2022	2023	…	2033	2034
Benefits*	0	0	0	0	2,023	2,223	…	5,180	5,793
Residual benefits	0	0	0	0	0	0	…	0	24,356
Project cost relative to do-nothing option	650	18,000	15,000	600	0	0	…	0	0
Net benefit	-650	-18,000	-15,000	- 600	2,023	2,223	…	5,180	30,149
NPV	7,919								

* Benefits include the value of unserved energy, safety risk and major repairs.

This option delivers a net benefit of $7.9 million in 2018 dollars. The project comes online in 2021, with a rolling set of repairs commencing in 2018.

Analysis of non-network options reveals a demand management option, which can defer the start of repairs by one year, by covering a portion of the load at risk. The project is completed on otherwise the same schedule as in table 8.

Table 8: Preferred option with one year deferral ($2018, '000)

Year	2018	2019	2020	2021	2022	2023	…	2033	2034
Benefits*	0	570	732	1,097	1,474	2,223	…	5,180	5,793
Residual benefits	0	0	0	0	0	0	…	0	25,117
Network cost	0	650	18,000	15,000	600	0	…	0	0
Demand management cost	0	578	731	1,130	1,563	0	…	0	0
Net benefit	0	-658	-17,999	-15,033	- 688	2,223	…	5,180	30,910
Present value of demand management costs	3,352								
NPV	7,919								

* Benefits include the value of unserved energy, safety risk and major repairs.

As the projects have equal net benefits, it would be open to the distributor to select the project with demand management costs option as the preferred option. If this option is chosen and demand management is committed, then this project is eligible to receive the cost multiplier of up to 50 per cent. The cost multiplier is applied to the demand management costs and would result in an incentive of about $1.7 million, leading to a total demand management cost of approximately $5.0 million ($3.3 +1.7 million). Given the project's net benefit is $7.9 million, the net benefit constraint does not apply.[125]

This example illustrates a project that is currently net benefit neutral, but has the capacity to delay capex. As distributors become more familiar with demand management technology and the market's capabilities increase, these deferrals could cover longer periods.

B.2 Kangaroo Island worked example

We have based this worked example on SAPN's RIT–D for the Kangaroo Island submarine cable. This worked example is for illustrative purposes only and was also included in the explanatory statement to the draft Scheme. As noted later, the preferred option for the identified need in this RIT–D entailed installing a new 33kV

[125] If the distributor had a smoothed revenue requirement (AR) of $800 million, the maximum incentive they could receive in one regulatory year would be $8 million (being 1.0 per cent of AR). Therefore, if the distributor had already committed $7 million worth of projects in the regulatory year the incentive paid on this project would be $1 million rather than $1.7 million.

submarine cable.[126] If the Scheme was in place at the time of this RIT–D assessment, the outcome would not have changed. That is, none of the non-network options SAPN considered would have been preferred options, and therefore none of these options would have been eligible projects under the Scheme.

Demand management costs under non-network options

During this RIT–D process, SAPN received three technically credible non-network options to address the identified need. Table 9 summarises these options, along with SAPN's ex-ante estimates of these option's associated capex and opex costs as set out in its RIT–D final project assessment report.

Table 9: Ex-ante expenditure components of technically credible non-network options for Kangaroo Island submarine cable

Proposed non-network option	Estimated capex component	Estimated opex component
1: A combination of biomass, solar and diesel generation solution.	$6.7 million: Kingscote Substation upgrade for new generation connection for proponent. Line protection upgrade; plus $1.3 million: Dedicated underground cable connection from proponent's power plant to Kingscote Substation	$1.95 million per annum, escalating at CPI: A standing charge for basic network support during the evaluation period; An hourly fee of $300 per MWh (escalating at CPI): paid when demand exceeds 7.5MW, which requires the use of diesel generator; $0.65 million: Technical evaluation, connection and support agreements, commissioning, project management and engineering excluding design costs for the connection assets; $0.2 million per annum: Operational management during the evaluation period; plus Additional fuel cost when operating the Kingscote Generators when the proponent's power plant or connection from proponent's power plant to Kingscote Substation fails.
2: A generation solution consisting of wind, solar and diesel generation combined with short-term battery storage.	$8.3 million: in 2018, Penneshaw Substation upgrade for new solar/wind generation connection, Kingscote Substation upgrade for new diesel generation, and upgrade line protection for lines between Kingscote, American River and MacGillivray Substations. $1.7 million: Dedicated overhead line connection from proponent's power plant to Penneshaw Substation;	$4.27 million per annum, fixed : Capacity payment charge for basic network support during the evaluation period; $0.75 million per annum, escalating at CPI: Capacity payment charge during the evaluation period ; $315 per MWh (fuel and variable O&M) (escalating at CPI): Energy payment 2 for the use of diesel generator sets to provide base load; $0.65 million: Technical evaluation, connection and support agreements, commissioning, project management and engineering excluding design costs for the connection assets; plus $0.2 million per annum: Operational management during the evaluation period.
3: A generation	$7.8 million: Kingscote,	$2.7 Million per annum, escalating at CPI : Capacity

126 SAPN, *Final project assessment report: Kangaroo Island submarine cable*, 23 December 2016, p.46.

solution consisting of solar and diesel generation combined with short-term battery storage. This option also included a turn-key solution for a permanent 10MVA submarine cable across Backstairs Passage in the event of a failure of the existing submarine cable.	MacGillivray, American River and Penneshaw Substation upgrades for new diesel/solar generation; \$0.4 million: Raise the design temperature of the American River to MacGillivray line to provide adequate line thermal capacity; plus \$1.76 million: Installing a Voltage Regulator at Penneshaw Substation to provide voltage support.	payment charge for basic network support during the evaluation period; \$0.65 million : Technical evaluation, connection and support agreements, commissioning, project management and engineering excluding design costs for the connection assets; plus \$0.2 million per annum: Operational management during the evaluation period.

Source: SAPN, *Final project assessment report: Kangaroo Island submarine cable*, 23 December 2016 pp. 26–30.

Given the information available in SAPN's final project assessment report, we would form the view that the opex items in table 9 reflect expected demand management costs for the purpose of calculating project incentives under the Scheme.

We would not base project incentives on any of the capex items. These costs relate to network (or supply-side) solutions where the distributor provides assets to convey or control the conveyance of electricity to a customer.

Table 11 applies the information from SAPN's final project assessment report to the project incentive calculation in equation 1 under the Scheme. The figures in table 10 are based on SAPN's assumption of 'standard growth'.

Table 10: Breakdown of ex-ante costs under non-network options (\$ mil)

Option	Expected capex (network component)	Total expected cost (opex + capex)	Expected demand management costs (opex component)
1: Biomass, solar, diesel	$\begin{aligned}&\mathit{Substation\ upgrades}\\&+\mathit{underground\ cable\ connection}\\&= 6.7 + 1.3 = 8.0\end{aligned}$	33.558	$33.558 - 8.0 = 25.558$
2: Wind, solar, diesel	$\begin{aligned}&\mathit{Substation\ upgrades}\\&+\mathit{overhead\ line\ connection}\\&= 8.3 + 1.7 = 10.0\end{aligned}$	100.612	$100.612 - 10.0 = 90.612$
3: Diesel, solar + future cable	$\begin{aligned}&\mathit{Substation\ upgrades}\\&+\mathit{raising\ line\ design\ temperature}\\&+\mathit{install\ voltage\ regulator}\\&= 7.8 + 0.4 + 1.76 = 9.96\end{aligned}$	42.531	$42.531 - 9.96 = 32.571$

Source: SAPN, *Final project assessment report: Kangaroo Island submarine cable*, 23 December 2016, pp. 26–30, AER analysis.

Applying the project incentive calculation

Table 11 applies the information from SAPN's final project assessment report to the project incentive calculation in equation 1 under the Scheme. The figures in table 11 are based on SAPN's assumption of 'standard growth'.

Table 11: Illustrative project incentive calculation for different non-network options ($ mil)

Option	50% of expected demand management costs	Total expected benefit relative to base case*	Total expected cost relative to base case*	Net benefits relative to base case*	Project incentive (equation 1 of the draft Scheme)
1: Biomass, solar, diesel	$25.558 \times 50\%$ = 12.779	5.645	42.319 – 33.558 = (8.761)	5.645 + 8.761 = 14.407	$\min\begin{Bmatrix}12.779;\\14.407\end{Bmatrix}$ $= 12.779$
2: Wind, solar, diesel	$90.612 \times 50\%$ = 45.306	12.522	42.319 – 100.612 = 58.292	12.522 – 58.292 = (45.770)	0
3: Diesel, solar + future cable	$32.571 \times 50\%$ = 16.285	7.344	42.319 – 42.531 = 0.211	7.344 – 0.211 = 7.133	$\min\{16.285;\ 7.133\}$ $= 7.133$

Source: SAPN, *Final project assessment report: Kangaroo Island submarine cable*, 23 December 2016, p. 46; AER analysis.

* The base case, in this example, entails running the existing submarine cable to failure.

For clarity, no option in table 11 constituted a preferred option in SAPN's RIT–D. The preferred option for this identified need had an estimated net benefit of $24.035 million and entailed installing a new 33kV submarine cable.[127] As such, none of these projects would have been eligible for incentives under the Scheme. However, if the non-network options in table 11 were the only credible options, SAPN would select the first option, based on biomass, solar and diesel generation. Out of the three options in table 11 , this option had the highest expected net benefit relative to the base case ($14.407 million).

If the first option did not exist, SAPN would then select the third option, which had the next highest expected net benefit relative to the base case ($7.133 million).

If only the second option and the base case option existed, SAPN would choose the base case option of doing nothing (that is, running the cable to failure). This is because the key driver of the identified need was to maintain security of supply to Kangaroo Island, not for reliability corrective action.[128] As such, any proposed solution would need to provide a positive net market benefit to satisfy the requirements of the RIT–D

127 SAPN, *Final project assessment report: Kangaroo Island submarine cable*, 23 December 2016, p.46.

128 SAPN, *Final project assessment report: Kangaroo Island submarine cable*, 23 December 2016, p.18.

assessment. The second option has an expected net benefit of -$45.770 relative to the base case and would therefore not meet this criterion.

Applying the total financial incentive calculation

If the first option in table 11 was an eligible project and SAPN committed this project in 2015–16, it would accrue a project incentive of $12.770 million for that year. Assume that SAPN committed this eligible project in 2015–16 and its AR in 2015–16 was $682.03 million. In this case, 1.0 per cent of SAPN's AR (that is, its total incentive cap) would be 6.82 million.[129] In this case, since project incentive would have been $12.770 million, the constraint in equation 2 in the draft Scheme would bind, which specifies that:

$$\text{Total financial incentive}_t \leq AR_{t-2} \times 1\%$$

$$\text{Total financial incentive}_{2015-16} \leq 6.82 \text{ million}$$

In this example, SAPN would have received a total financial incentive of $6.82 million for 2015–16. Due to the two-year lag, SAPN would recover the total financial incentive of $6.82 million from customers in the 2017–18 regulatory year.

[129] This equates to SAPN's annual smoothed revenue requirement (AR) for year 2015–16, ignoring any potential outcomes of ongoing appeal processes.

C Submission summary — Draft Scheme

Table 12 summarises stakeholder submissions we received on the draft Scheme we published on 28 August 2017. We have made these submissions available on our website.[130]

Table 12: Summary of submissions on the draft Scheme

Submission	Summary	Response
AGL, *Submission on the draft demand incentive scheme and innovation allowance mechanism*, 13 October.	1. While the Scheme can provide some useful incentive in the short term, the existence of the Scheme should not impede more significant reform to enable more natural incentives for distributors to operate efficiently. 2. AGL references the AEMC's draft decision on the contestability rule change. It holds the view that demand management (DM) projects cannot occur behind the meter. 3. The Scheme must be designed in such a way as to build on the capacity of the competitive market to deliver DM programs. 4. We are not as optimistic as the AER that the draft scheme will operate in a neutral manner towards distributors' in-house suppliers. We anticipate that a careful monitoring of the tendering process as well as an assessment of the parties that are successful in the tender process should determine over time if there is a bias towards ring-fenced entities providing services to regulated parent distributors.	1. We do not foresee the Scheme impeding reforms. We intend to approach regulatory incentives holistically, and will review the Scheme as regulatory and market changes occur. 2. The Scheme will not reward projects that the NER disallows. If the NER changes to prevent DM projects from occurring behind the meter, the Scheme will still be relevant for rewarding distributors for procuring DM services from third parties where this efficiently alleviates a constraint on the distribution network. 3. We have designed the Scheme to build the capacity of the competitive market to deliver DM by requiring distributors to procure third party DM when efficient. 4. The Scheme's minimum project evaluation requirements will promote transparency and competitive tension within distributors' procurement practices, which will prevent distributors from favouring in-house options or options provided by related parties. The Scheme's compliance reporting requirements will make public the proportion of projects under the Scheme are going towards third parties versus related parties and in-house options. Ring-fencing requirements should stop preferential treatment towards related parties, and we will investigate any compliance concerns associated with the ring-fencing guideline.
Ausgrid, *Submission on draft demand management incentive scheme and innovation allowance mechanism*, 12 October 2017.	1. Welcomes the draft Scheme, which it considers will deliver value to consumers. Together with the Mechanism, this will kick start investments to deliver greater use of non-network solutions to meet network needs. This will benefit consumers by reducing the longer-term costs of operating the network.	1. The final Scheme is broadly consistent with the draft Scheme. 2. While we understand the appeal of a smoothing mechanism, our intent for setting the total incentive cap on annual basis was to encourage the Scheme to take effect quickly. While this also limits the size of the incentive available in any year, we are

[130] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism/draft-decision.

	Commends the AER for designing a Scheme that can apply to DM's use in deferring the replacement of aged assets. 2. Suggests introducing a smoothing mechanism to remove the disincentive to undertake projects with significant up-front expenditure. The current disincentive arises as the total incentive cap applies on an annual basis rather than over a wider period. This could be resolved by allowing any part of the cap not used to be carried over into subsequent years.	satisfied that the total incentive cap is sufficiently large to avoid this concern. It is also worth noting that since the incentive over the life of the project accrues in the project commitment year, this aspect of the Scheme should not disadvantage projects with upfront-heavy expenditure profiles.
AusNet Services (Ausnet), *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017.	1. Supports the draft Scheme overall, including the: definition of DM, minimum project evaluation requirements, the cost multiplier of 50%, decision not to adjust other incentive schemes. 2. The 50% cost multiplier should be fixed for the duration of each regulatory period. Does not agree that the AER will sufficiently limit regulatory risk by guaranteeing not to change a project's uplift after the distributor has made a project commitment as this would not protect projects that are in the pre-commitment negotiation stage. Allowing changes during the regulatory period, introduces unnecessary regulatory risk and uncertainty. 3. Reduce compliance reporting requirements to focus on information required to administer the Scheme. The current requirements include annual ex-post assessments of the benefits from delivered DM projects, which could be burdensome (for example, some DM projects may deliver benefits for over 25 years).	1. The final Scheme has maintained the elements supported by AusNet. 2. We have not adopted this suggestion. While we can change the cost multiplier mid-regulatory control period, we must undertake distribution consultation procedures before we can amend the cost multiplier set in the Scheme. We consider this will provide sufficient lead-time for distributors to progress negotiated projects to the commitment stage. 3. We have not adopted the suggestion to remove the reporting of ex-post benefits under the Scheme, and note that several submissions voiced that the requirements in the draft Scheme were too weak.
Business SA, *Submission on the draft demand management incentive scheme and innovation allowance mechanism*, 10 October 2017.	1. Agrees that network businesses need encouragement to look for non-network solutions (although SAPN is not overusing network options to the same extent as QLD or NSW distributors). The AER should consider any incentive in the context of the rapidly changing electricity market where there has been significant market response. 2. All large market customers are already on demand based tariffs so are incentivised to reduce demand during times of network constraints. Also questions the need for the Scheme if network tariff settings are right.	1. The Scheme aims to provide this encouragement where DM is the most efficient way to meet an identified need. By setting the magnitude of the incentive in the Scheme as opposed to on a reset-by-rest basis, we have greater flexibility to vary the incentive in response to changes in the market. 2. While many large market customers are already on demand-based tariffs, there may also be a need to use network-based DM on geographic segments of the distribution network where there are no large market customers. We note that outside of the Scheme, we are already requiring distributors to move towards more cost-reflective pricing for all customers, but we recognise this will be a very gradual process,

	3. Agrees with defining DM broadly. Any generation or battery support to offset additional network spending needs to be put to the market on a competitive basis so proponents will bid against one another to deliver required network support at least cost by maximising the total market benefit of that non-network support. 4. The AER should avoid overlaying incentives and suggests we consider AEMO's proposal to offset demand, and try to ensure that distributors are not getting both sets of incentives.	and therefore the Scheme aims to deliver value to consumers in the meantime. 3. We have designed the Scheme around requiring a competitive procurement process. This design feature should help achieve this effect. 4. We have revised the draft Scheme so we only base project incentives under the Scheme on expenditure that is net of any subsidies the distributor receives for that project. Also, AEMO's proposal targets DM at the wholesale generation level (to manage generation supply shortfalls), whereas the Scheme targets DM at the distribution level (to manage network constraints).
CarbonTRACK, *Submission on draft demand management incentive scheme and innovation allowance mechanism*, 12 October 2017.	The Scheme should encourage cross-collaboration and support third party involvement.	We discuss CarbonTRACK's comments more in Attachment A of Mechanism's explanatory statement, as many of these comments better relate to the Mechanism. The final Scheme maintains the requirement under the draft Scheme for solutions to have undergone competitive testing before they can be eligible to receive an incentive under the Scheme. This should encourage third party involvement.
Clean Energy Council (CEC), *Submission on draft demand management incentive scheme*, 12 October 2017.	Is concerned with having project eligibility requirements tied to meeting an 'identified need', which is defined in the NER as the objective a network business seeks to achieve by investing in the network. The CEC shares Energy Queensland's concerns that this would exclude viable DM projects that are tied to a network risk rather than an immediate investment	We have maintained the reference to 'identified need' in the final Scheme as this helps give effect to the Scheme Objective in the NER. The NER tie this objective to incentivising 'non-network options', which they define as 'a means by which an identified need can be fully or partly addressed other than by a network option'. The Scheme should be sufficiently flexible to not restrict Energy Queensland's approach to network planning. We have removed some of the draft Scheme's terminology that might have otherwise unintentionally restricted its application—such as the need to have an identified preferred option when testing the market, and the reference to comparing credible options to the preferred network option. We have also added some clarification on what we expect from the Scheme's net benefit analysis in the explanatory statement. We will continue to liaise with Energy Queensland to see if our assessment approaches are creating unintended barriers to how distributors could procure efficient DM solutions.
Central Victorian Greenhouse Alliance (CVGA), *Submission on demand management incentive scheme early application rule change consultation paper*, 7 September 2017. Northern Alliance for Greenhous Action (NAGA),	1. Would like to see the aspect of the Scheme that incentivises collaboration strengthened as DM is not just a technical issue that a third party provider can step in and solve. Rather, DM requires working with stakeholders outside the energy sector, engaging and collaborating with households, businesses, government organisations and industry. The energy sector could from the water sector, where multi-stakeholder partnerships are more common, and upstream and	1. The Scheme Objective is to provide distributors with an incentive to undertake efficient expenditure on relevant non-network options relating to DM. In service of that objective, we have included project evaluation requirements that support third parties getting involved in the project proposal stage. We consider this step should encourage greater collaboration and third party engagement. When evaluating net benefits of different projects under the Scheme, we require distributors consider upstream and downstream market benefits. 2. While distributors are required to consult on

Submission on demand management incentive scheme early application rule change consultation paper, 10 October 2017. Eastern Alliance for Greenhouse Action (EAGA), *Submission on demand management incentive scheme early application rule change consultation paper*, 10 October 2017.	downstream impacts and benefits are more holistically considered. 2. Current consumer engagement processes for network planning are overwhelmingly complex and time consuming for local (and to a lesser extent state) governments to proactively engage with. Distributors have consulted with local government seeking a substation upgrade, a few days prior to a RIT-D due date.	non-network options when completing RIT–Ds, they do not receive an explicit incentive when they find a non-network option is preferable. Under the Scheme, they will receive an explicit incentive. We consider this will encourage distributors to be more proactive in making this process as user-friendly as possible, so they can procure attractive DM projects. Also, in June 2017, we introduced a Distribution Annual Planning Report Template to make engaging with networks and understanding network constraints more straightforward. In addition to this, we will be reviewing the application guidelines for the RIT–D (along with the RIT–T) in 2018.
Citipower, Powercor and United Energy, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 11 October 2017.	Supports the proposed Scheme, including the cost multiplier and definition of DM. Suggests increasing or removing the total incentive cap, as the net-benefit constraint is sufficient to delivering value to electricity consumers.	The final Scheme maintains the components of the draft Scheme that Citipower, Powercor and United Energy explicitly support. We have decided to maintain the cap, at least for the first version of the Scheme. The total incentive cap reduces the risk of providing an unreasonable incentive that over-compensates distributors at the cost to electricity consumers. Depending on how the industry reacts to the Scheme and its implementation, there is scope to alter the total incentive cap in future versions of the Scheme.
Derek Fern, *Submission on draft decision: Demand management incentive scheme and innovation allowance*, 5 September 2017.	1. It is misleading that the balance of the document focusses on distribution networks. The AER omitted the following constraints: insufficient generation capacity and transmission constraints. 2. The current push on DM is no substitute for a comprehensive national energy policy with long term generation and transmission planning. DM is a late and hurried attempt to offset government inactivity with the justification of avoiding further network costs. 3. To allow distributors to interrupt or curtail supply requires investment on both sides of the meter. Costs related to the load side of the meter will i rest with the consumer, and the proposed Scheme appears to impose the supply side costs on the consumer via “use of system” charges. Voltage reduction could be an alternative,	1. We agree DM has value in addressing energy supply shortages at peak and transmission network constraints. The Scheme focuses on the distribution network because, under the NER, the Scheme is limited to distribution networks. That said, when assessing options to address distribution network constraints, distributors must consider net benefits at other parts of the supply chain, including at the generation and transmission levels. 2. While DM is no substitute for comprehensive national policy, it is an important component (among many) to optimising the use of the NEM. We do not agree that the Scheme is a hurried attempt to offset inactivity in managing network costs. It originated from a holistic review of consumer choice undertaken by the AEMC in 2012.[131] This resulted in several reforms that we have been gradually implementing. 3. DM has costs and benefits. The Scheme only incentivises 'efficient' DM that a cost-

[131] See AEMC, *Final report: Power of choice review — giving consumers options in the way they use electricity*, 30 November 2012.

	which has previously been adopted elsewhere. 4. DM has been historically ineffective because it relied on punitive tariffs to limit consumption for an initial period until consumers reverted to their previous usage patterns.	benefit analysis has shown has the highest net benefit. 4. This point appears to relate to time of use pricing. There are many enablers of DM, including critical peak pricing, direct load control, embedded generator network support, virtual power plants and more. Depending on time and location, different DM solutions are sometimes effective and economical, and at other times not. The Scheme aims to only incentivise DM projects where they are effective and economical.
Energy Efficiency Council (EEC), *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, October 2017.	1. Supports the proposal to increase the incentive for distributors to undertake DM. 2. Prefers to base incentives on expenditure outcomes rather than expenditure itself. The draft Scheme incentivises less cost-effective projects. 3. The 50% cost multiplier may not reflect the full market benefits of some projects and the 1% of revenue cap will limit the total expenditure on DM projects, potentially below the economic potential. 4. Supports the requirement for distributors to run a competitive procurement process. Encourages the AER to create requirements that will avoid distributors from circumventing the third party competitive procurement process for in-house providers or partners. 5. Concerned with the proposed approach where distributors must demonstrate that non-network solutions are more cost effective than network solutions. Prefers the 'efficiency first' practice encouraged in Europe. They want Australian regulation to require distributors to consider demand-side investments before supply-side investments. 6. Agrees with requiring distributors to demonstrate the cost-effectiveness of expenditure, but feels the RIT-D process is particularly onerous and would like a streamlined approach for the assessment of DM projects under $5m. 7. Would like to establish minimum DM project targets to require distributors to undertake a specific level of DM with the expectation that they should invest well above this level. At a minimum, the AER should require distributors to report metrics on their overall investment in DM. Potential metrics for targets and reporting could	1. The final Scheme maintains a similar DM incentive to that proposed in the draft Scheme. 2. We agree that it would be ideal to tie the incentive to benefits rather than costs, but have maintained the cost multiplier approach for the reasons set out in the explanatory statements to the draft and final Schemes. 3. For the reasons set out in the explanatory statements to the draft and final Schemes, we set a 50% uplift to reduce the administrative burden of the Scheme, whilst recognising that it will likely be higher than optimal in some circumstances, and lower than optimal in others. We have decided to maintain the cap, at least for the first version of the Scheme. The total incentive cap reduces the risk of providing an unreasonable incentive that over-compensates distributors at the cost to electricity consumers. Depending on how the industry reacts to the Scheme and its implementation, there is also scope to alter the total incentive cap in future versions of the Scheme. 4. The Scheme's minimum project evaluation requirements will promote transparency and competitive tension within distributors' procurement practices, which will prevent distributors from favouring in-house options or options provided by related parties. The Scheme's compliance reporting requirements will make public the proportion of projects under the Scheme going towards third parties versus related parties and in-house options. 5. We have made some amendments to the draft Scheme that should go some of the way to address this concern, whilst recognising that the Scheme Objective in the NER is tied to incentivising efficient 'non-network options', which are defined as 'a means by which an identified need can be fully or partly addressed other than by a network option'. For a more detailed explanation, see our response to CEC. 6. For non-RIT–D projects, projects under the Scheme do not have to follow the RIT–D

	include annual: DM investment, DM outcomes (such as kW at peak reduction), value of supply-side augmentation avoided or deferred through DM, including upstream (net market) benefits.	requirements. We have clarified this by amending clause 2.3(5) of the draft Scheme. 7. We consider the project reporting requirements under the draft Scheme will go some way to achieve the EEC's expectation. Given NER clause 6.6.3 (5) prevents us from imposing penalties under the Scheme, it is difficult to see what setting targets would achieve other than 'naming and shaming'. Our commitment to publish an annual performance report would provide transparency.
Energy Networks Australia (ENA), *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017.	1. Supports the 50% cost multiplier, the definition of DM and the assessment against a do-nothing 'base case' (unless the project is for reliability corrective action) as set out in the draft Scheme. 2. Supports the net benefit cap and the total incentive cap. However, recommends smoothing the recovery of incentive payments. Since DM projects typically require a larger up-front payment and smaller ongoing payments, this may result in claims that are above 1% of allowed revenues in the first year but under this in the subsequent years. It would be desirable to achieve efficient DM uptake without causing unnecessary price volatility.	1. The final Scheme maintains these features. 2. Our intent for setting the total incentive cap on an annual basis was to encourage the Scheme to take effect quickly. This will also prevent the Scheme from causing price volatility as capping the incentive to 1.0% of allowed revenue would prevent price shocks in any year. In contrast, if the total incentive cap was set for an entire regulatory control period and without a revenue spreading mechanism, this could plausibly result in price shocks if many large projects were committed in one particular year within that period.
Enviroswim, *Submission on draft demand management incentive scheme*, 8 October 2017.	Advocated for using their product as a substitute for chlorine in place of having pool pumps on load-controlled tariffs.	The submission provided insight into other potential ways for consumers to cut their demand as an alternative to direct load control. The Scheme does not advocate for any specific form of DM, only the option that creates the greatest net economic benefit across the relevant market.
Energy Queensland (EQ), *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 17 October 2017.	1. Is generally supportive of the Scheme, including the 50% cost multiplier and the definition of DM. 2. Minimum project evaluation requirements go some way to conducting a RIT–D and would appear to impose an administrative burden that is not commensurate with the project size. 3. Does not believe RIT-Ds are the most appropriate mechanisms to compare network and non-network solutions. Recommends further discussion on alternative methods for assessing DM project efficiency. 4. Suggested smoothing the cap over a regulatory control period, so to roll over any unused portion of the cap. 5. Does not agree with the requirement to provide a direct link to an identified need and accordingly, to a network investment. This limits DM projects	1. The final Scheme maintains these features. 2. Specifications under the minimum project evaluation requirements are essential for the distributor to have tested the market before identifying the most efficient option. Given the contestable nature of many DM services, market testing is a clear means to determine project efficiency and should occur irrespective of the Scheme's existence. 3. For non-RIT–D projects, projects under the Scheme do not have to follow the RIT–D requirements. We have clarified this by amending clause 2.3(5) of the draft Scheme. 4. See point 2 of our response to ENA's submission. 5. The Scheme Objective in the NER is tied to incentivising 'non-network options', defined as 'a means by which an identified need can be fully or partly addressed other than by a network option'. For more information, see our response to CEC.

	that could be tied to a network risk rather than an immediate investment. 6. Proposed reporting requirements appear disproportionately burdensome, particularly as this would duplicate the reporting of the Queensland distributors' DM project outcomes to the Queensland regulator. Prefers the compliance reporting requirements to be in the form of a modified RIN.	6. It is unclear why this would be burdensome if EQ already reports this information to the Queensland regulator. It would be prudent for distributors to understand the effectiveness of their projects, irrespective of the Scheme. This information, along with the results that other distributors will report, will help in identifying what works well, and what they should improve. This reporting requirement would not prevent us from issuing a modified RIN as a basis to request this information. We note, however, a written DM compliance report might better capture qualitative information.
GreenSync, *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 13 October 2017.	1. The Scheme has an important role in allowing networks to deliver upon the ENA Transformation Roadmap. 2. Option value calculations should be mandatory in all Scheme/Mechanism applications. 3. Project emphasis should be placed not only on large sized projects (such as RIT-D scale), but also on smaller value projects. The bundling or pooling of Scheme spend to allow for the delivery of many smaller projects would increase the efficiency for regulatory approvals and incentivise innovative solutions.	1. We acknowledge GreenSync's in-principle support for the Scheme. 2. Under the Scheme, option value benefits must be included in project evaluation requirements, to the extent they exist. Given including option value will likely increase the value of DM relative to network options, we consider the Scheme also incentivises distributors to include this value. 3. The Scheme applies to projects both outside of and within the RIT–D's scope. We have amended clause 2.3(5) of the draft Scheme to clarify that projects outside the RIT–D but under the Scheme do not have to meet the same RIT–D requirements. This should better encourage smaller value projects under the Scheme. Since a project-level cost–benefit analysis and market testing process needs to take place for individual non-network options, it is not clear that bundling small projects would be feasible or would notably lower the Scheme's administrative burden.
The Institute for Sustainable Futures (ISF), *Submission on draft demand management incentive scheme, innovation allowance mechanism and rule change consultation paper*, 12 October 2017.	1. General comments: the 50% cost multiplier cap and the total incentive cap are too conservative. Recommends the AER develop a guideline to provide greater clarity on how distributors should comply with the Scheme. This should include, as a minimum, guidance on how to calculating net benefits, standardised values for key factors, a standard reporting template and compliance metrics. 2. Streamline calculation of net market benefits by providing a guideline to estimate the benefits and costs to ensure consistency amongst distributors. We should base net benefit calculations on net benefits to consumers, rather than across the relevant market (that is, no longer explicitly including generators and transporters of electricity). 3. Correct typo to 'any other source'.	1. There is capacity to alter the cost multiplier and total incentive cap over time depending on distributor engagement with the Scheme. We have included some additional guidance what we might expect from a cost–benefit analysis for smaller projects in Attachment A of this explanatory statement. 2. We have maintained the test to maximise the net benefits to those who produce, transport and consumer electricity in the relevant market. However, we have introduced some simplicity by clarifying that distributors need not calculate the specific costs and benefits that cancel out between parties (that is, wealth transfers). For more of an explanation, see table 1 in this explanatory statement. 3. We corrected the typo, although we note that this typo is also included in the NER. We confirm that the incentive itself sits outside the opex building block, separately to the DM costs themselves which are recoverable through the distributor's total annual revenue.

Clarify DM costs recoverable from other sources in relation to 2.1.b of the draft Scheme

4. Make the distinction between the initial and final preferred options clearer.

5. The AER should remove the requirement to include an initial preferred option in a request for DM solutions. ISF also criticises the reference to a 'preferred network option' as it suggests the network option is the default option.

6. Characterisation of DM is too narrow. The AER should change references to 'request or control' to also include 'influence' to capture indirect forms of DM.

7. Allow project DM incentives to be lower than the incentive cap

8. Identifies a couple of typos where the draft Scheme refers to eligible projects when discussing committed projects.

9. Setting a maximum lead time when defining committed projects, and setting a maximum project expenditure period (suggests 5 years). The AER should permit distributors to recommit a DM project and seek further incentives at the end of this period.

10. Do not bind the Scheme to the RIT-D as this means the administrative burden will erode the net value of savings to electricity consumers. ISF suggests a much simpler cost benefit process to adopt.

11. Improved compliance reporting to include, reporting for all committed projects the year of commitment and value of DM incentive provided. They should also report the annual and cumulative: DM cost to the distributor, savings to the distributor, reduction in demand (kVA/year), reduction in energy consumption (MWh), reduction in carbon emissions, other benefits to the distributor, bill savings to customers, incentives provided to customers, reduction in value of customer energy at risk and total benefits to customers. The AER should provide templates on how to report this data and have a standardised reporting framework.

12. The AER must remedy the draft Scheme's lack of clarity on how customers can recover DM incentives for committed projects that do not

4. We have incorporated this suggestion.

5. We have incorporated this suggestion. It was erroneous in the draft Scheme to imply a network option should be the default option. We have also included the requirement to provide additional technical information as we consider this would help other parties respond to requests for DM solutions.

6. We have incorporated this suggestion.

7. We have incorporated this suggestion.

8. We have corrected these typos.

9. We have included a maximum lead time as suggested, since this allows for a sensible in-built compliance measure that will help the Scheme deliver value to electricity consumers. For further explanation, see section 9.3. We have not included a maximum project expenditure period. Since the incentive is accrued ex-ante, this would increase the Scheme's complexity and administrative burden, whilst potentially limiting the size of the incentive.

10. For non-RIT–D projects, projects under the Scheme do not have to follow the RIT–D requirements. We have clarified this by amending clause 2.3(5) of the draft Scheme.

11. We have maintained the compliance reporting requirements in the draft, which already cover a number of ISF's suggestions.

12. We have incorporated this suggestion.

13. We have incorporated this suggestion by providing distributors with one month between these steps.

	proceed as planned 13. The AER appears to have an impractical timeline as distributors should have at least one month between when the AER determines the total financial incentive and it submits its annual pricing proposal.	
Major Energy Users (MEU), *Submission on draft demand management incentive scheme and innovation allowance mechanism*, 9 October 2017.	1. Except where detailed, supports the draft Scheme. 2. The cost multiplier incentivises eligible projects that are the highest cost. The Scheme must reward the lowest cost DM option. The AER could assess each DM option in terms of total costs to consumers (that is, DM cost plus bonus). The AER could also link the incentive to value for consumers rather than the cost to networks. 3. If a distributor terminates a project under the Scheme early, will it return the incentive? 4. The AER's justification for a 50% uplift as being commensurate to a 6.5 year return does not work if the DM project only defers network augmentation for 1 year. Also, if the distributor extends the DM project over multiple years, this could cause consumers to pay more than the benefits warrant.	1. We note MEU's support for the draft Scheme, unless it has stated otherwise. 2. An eligible project is one that is identified as being an 'efficient non-network option'. An efficient non-network option is the credible option that maximises the present value of the net economic benefit across the relevant market. This will ensure that out of a set of eligible options to address an identified need, the Scheme will only reward the most efficient option chosen. We are satisfied that the net benefit constraint would also go some of the way to address MEU's concern. 3. Yes, we have added clause 2.4(7) to the Scheme to capture this. 4. This was one high-level justification to show the 50% uplift would likely be broadly reasonable on average. While this may be a little conservative in some instances, and generous in others, we consider this limitation is less than the costs of calculating the incentive on a project-by-project basis, which would undermine the value of the Scheme –particularly for small projects. Moreover, DM projects that provide a one year deferral will be smaller, and should therefore have commensurately lower costs (and smaller incentive payments). Also, since the incentive is based on ex-ante costs, extending the DM project will only occur when it is efficient to do so, and would not result in consumers paying a higher incentive.
Red Energy and Lumo Energy, *Re: Demand management incentive scheme and proposed early application rule change consultation paper*, 12 October 2017	1. Do not support the AER’s proposed application of the Scheme. This Band-Aid solution will not mitigate the perceived bias towards capex over opex. Without a thorough investigation into the incentive regulatory arrangements that have contributed to the capex investment bias, distributors will continue to overlook demand side solutions. Also, changes to the Scheme could be futile as distributors will unlikely be able to directly invest behind the meter and the AEMC will undertake a broader review of the incentive regulatory framework in 2018. 2. Implementing the generous Scheme at this time will have unintended consequences as it applies to the distribution ring-fencing guideline. A	1. The final Scheme is substantially similar to the draft, which we consider will meet the NEO and Scheme Objective for the reasons set out in the explanatory statements for both the draft and final Scheme. The Scheme will not be futile if the AEMC changes the NER to prevent distributors from directly investing behind the meter. Rather, the Scheme will be relevant for rewarding distributors for procuring DM services from third parties where these efficiently alleviate distribution network constraints. Irrespective of any rule change, we anticipate that most DM under the Scheme will occur via distributors procuring services from other parties. 2. The Scheme's minimum project evaluation requirements will promote transparency and competitive tension within distributors' procurement practices, which will prevent

	50% uplift will provide distributors with leverage to award demand side contracts to their ring-fenced affiliates by allowing the affiliate to price the demand side option more aggressively than their competitors. Any loss the distributor incurs in doing this to keep these projects within the same corporate group will be offset by the 50% uplift. As such, they recommend that if the AER applies a Scheme, applying an uplift payment of less than 10%. Also, if the AER maintains the 50% uplift, it must require greater transparency of contracts between a distributor and a ring fenced affiliate. While this may inadequately address their ring-fencing concerns, transparency will provide an improved understanding of any demand side contracts entered into between distributors and their ring fenced affiliates.	distributors from favouring in-house options or options provided by related parties. The Scheme's compliance reporting requirements will make public the proportion of projects under the Scheme are going towards third parties versus related parties and in-house options. Ring-fencing requirements should stop preferential treatment towards related parties, and we will investigate any compliance concerns associated with the ring-fencing guideline.

SA Power Networks (SAPN), *Submission on the draft demand management incentive scheme, innovation allowance mechanism and proposed early application rule change*, 12 October 2017.	1. Supports many aspects of the draft Scheme, including the 50% cost multiplier, the net benefit constraint, neutrality on who provides the DM, the broadened definition of DM, ex-ante incentive payments, a non-prescriptive approach to calculating option value. 2. Increase the total incentive cap to 1.5% of the annual allowable revenue. This will be consistent with the network capability incentive allowance and would not pose a risk to customer due to the net-benefit constraint. 3. Incentive payments, as separate from the actual costs, should be explicitly excluded from the EBSS. SAPN also believes that including the DM opex in opex-specific benchmarking would generate misleading information on efficiency 4. SAPN suggests removing the requirement that distributors must report on DM projects considered as being potentially eligible in part B of the compliance report. They do not see value in the requirement to report on projects that have been considered unsuitable for commitment. 5. SAPN requests clarification that the comparator for the net benefit analysis would be a least cost option if the project was addressing a reliability requirement, and that reliability corrective action projects can have net costs. 6. SAPN suggests the distributors should not have to provide a preferred option when placing a request for DM solutions. Distributors may not have identified a preferable option yet and be placing the request to get offers. Clause 2.2.1(4)(d)	1. The final Scheme retains the components of the draft Scheme that SAPN supports. 2. The 1.0% total incentive cap strikes an appropriate balance between not being too restrictive and providing an initial layer of protection to consumers (in case the Scheme does not operate as effectively as planned). There is scope to revisit the total incentive cap after the Scheme is implemented. This flexibility will allow us to revise the total cap in the future, depending on how the industry reacts to the current cap. 3. Our intention is for the total incentive payment under the Scheme to sit outside the opex building block, and would therefore not relate to the EBSS. We have clarified this in this explanatory statement. We have not seen any strong reasoning to support excluding efficient DM opex from opex-specific benchmarking. In any case, this issue relates to expenditure assessments and performance reporting more broadly, as opposed to the Scheme in particular. 4. We consider this information is required for us to verify that the distributor has been undertaking market testing and has been selecting projects with the highest net benefit. This will help us monitor compliance with the minimum project evaluation requirements under the Scheme, and, if need be, scrutinise the outcome of distributors' net benefit analyses. 5. We have clarified this wording in the final Scheme. The expected relevant net benefit of the preferred option must have a positive NPV when assessed against a base case of doing nothing, unless the project is for reliability corrective action. Since for reliability projects, the distributor will use the credible option with the second highest net benefit as the base case, any efficient DM project will have a positive net benefit (even if it would have had a net cost relative to doing-nothing). 6. We have incorporated this suggestion.
South Australian Council of Social Service (SACOSS), *Submission on draft demand management incentive scheme, innovation allowance mechanism and proposed early application rule change*, 28 September 2017.	The new Scheme aligns with its objective and will promote the delivery of a more efficient network, ultimately reducing costs to consumers. While customers will bear the cost of the incentive payments under the Scheme, they will also receive the benefits from DM as a more efficient network in the longer term. SACOSS supports the AER in not confining 'network constraint' to peak demand in its definition of DM. Given SA's recent system failures, SACOSS strongly supports measures which encourage distributors to undertake projects that will manage diverse power flows and deliver	While we have made some amendments since the draft Scheme, we consider the final Scheme maintains the elements that SACOSS has supported in its submission.

	greater system security. SACOSS supports the efficiency test for proposed DM projects to address network constraints. The cost multiplier of up to 50% of the costs of eligible DM projects assessed as efficient is a reasonable starting point, recognising that the amount may be varied in future versions of the Scheme. SACOSS supports the project cap, the overall cap of 1.0% of MAR, and the AER's approach to balancing the need for reporting and transparency with keeping distributors' administrative costs low.	
Swimming Pool and Spa Association of Australia (SPASA), *Submission on draft demand management incentive scheme and innovation allowance mechanism*, September 2017.	DM that affects filtration pumps reliant on rooftop solar heating will threaten the swimming pool solar heating sector, which must operate in optimal summer conditions to be effective. Pool and spa owners should not have to pay for increased DM and innovation when they have already invested in products to reduce the electricity load in their home. DM that interferes with pool servicing may have significant imposts. DM-related costs do not make it feasible to continually turn pumps off and on, as doing so has health and operational consequences as it affects pools' chemical balanced and filtered state. DM in public pools and aquatic centres may push costs up and cause health risks. The pool and spa industry does not wish to be seen as a convenient energy reduction target, even when pool pump load demand is significantly less during the peak periods when compared with more energy intensive appliances.	It is not the intention of the Scheme to impose mandatory DM programs. Also, the DM projects we are aware of tend to be opt-in. The Scheme should incentivise distributors to proactively approach the market to identify efficient ways to use DM to address constraints they identify on their networks. By promoting more efficient investment decisions, we see the Scheme as reducing, rather than increasing, the long-term costs of electricity consumption. Several of SPASA's concerns appear to relate to tariff structures. While distributors must move towards more cost-reflective pricing, this process is occurring gradually and is independent of the Scheme itself. It is not clear how SPASA considers the Scheme will be negative on the use of rooftop solar heating. From what we have seen to date, DM programs often favour rather than penalise solar-based solutions, particular when complemented with battery storage and internet of things devices.