Explanatory statement

Draft demand management incentive scheme

Electricity distribution network service providers

August 2017

AUSTRALIAN
ENERGY
REGULATOR

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: DM@aer.gov.au

AER reference: 58882

Request for submissions

The Australian Energy Regulator (AER) invites interested parties to make written submissions regarding this paper by the close of business **12 October 2017**.

Interested parties should send submissions electronically to: DM@aer.gov.au.

Alternatively, people can mail submissions to:

Mr Warwick Anderson
General Manager, Network Finance and Reporting
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

We prefer that all submissions be publicly available to facilitate an informed and transparent consultative process. We will treat submissions as public documents unless otherwise requested.

We request parties wishing to submit confidential information to:

- Clearly identify the information that is the subject of the confidentiality claim.

- Provide a non-confidential version of the submission in a form suitable for publication.

We will place all non-confidential submissions on our website at www.aer.gov.au. For further information regarding our use and disclosure of information provided to us, see the ACCC/AER Information Policy, June 2014 available on our website.

Please direct enquiries about this paper, or about lodging submissions, to DM@aer.gov.au or to Lisa Beckmann on (02) 9230 9164.

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
ARENA	Australian Renewable Energy Agency
capex	Capital expenditure
compliance report	The demand management compliance report required under subclause 2.4.1 of the draft Scheme
credible option	Has the meaning given to it in NER clause 5.15.2(a)
DAPR	Distribution annual planning report
demand management	For the purpose of the draft scheme, this relates to network demand management. This is the act of modifying the drivers of network demand to remove a network constraint.
distributor	Distribution network service provider
EBSS	Efficiency benefit sharing scheme
eligible project	As defined under 2.2.1) of the draft 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
minimum project evaluation requirements	As defined under clause 2.2.1 of the draft scheme
MWh	Megawatt hour or 1,000 kilowatt hours
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
non-network options	As defined in chapter 10 of the NER
NPV	Net present value
opex	Operating expenditure
preferred option	Has the meaning given in NER clause 5.17.1(b)
project incentive	The maximum financial incentive a project can accrue, as determined under equation 1 in the draft Scheme with respect to a project, i.
RIN	Regulatory information notice
RIT-D	Regulatory investment test for distribution

Shortened form or term	Extended form or definition
the Scheme	the demand management incentive scheme
the Scheme Objective	The demand management incentive scheme objective

Contents

1 Introduction

This explanatory statement accompanies the draft demand management incentive scheme (Scheme). We have designed the draft 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. In this context, we take '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:

- 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).

- Engagement with stakeholders, including how we accounted for their views in developing the draft Scheme.

- Proposed application of the Scheme in the regulatory determination process for individual distributors. This explains our decision to apply the incentive on efficient demand management projects as a cost multiplier of 50 per cent.

- Proposed 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.

- Proposed 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 year.

We also summarise the different mechanisms we discussed in our Consultation Paper, including why we have either incorporated them, or excluded them from the draft Scheme.

---

[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 draft Scheme uses the term, 'relevant market', as opposed to the NEM.

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

Figure 1: Outline of the draft 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 an eligible project that delivers a net benefit to retail customers.

Compliance reporting

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

AER use of compliance report to determine financial incentive

AER reviews the total financial incentive a distributor accrued and publishes a performance report on how distributors used the scheme.

Application of incenitve payment

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

In tandem to publishing the draft Scheme and this explanatory statement, we have also published:

- A draft demand management innovation allowance mechanism (Mechanism) and its accompanying explanatory statement.

- A consultation paper relating to a prospective rule change proposal for early implementation of the Scheme.

We encourage stakeholders to consider these documents together when formulating their response.

2 Background

2.1 Our rationale for the Scheme

The Scheme will operate alongside a separate Mechanism that we are developing 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. 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.[2]

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 commence in December 2017. We have also increased transparency in a way that will facilitate the contestable market in facilitating demand management. For instance, we initiated a new rule that will increase the transparency of network businesses' plans to retire and replace assets. We have also recently released a user-friendly distribution annual planning report template to better assist non-network business in developing demand-side solutions to address network constraints.[3]

However, fully realising the benefits of these reforms will take time. For example, we agree with the AEMC's view that:[4]

---

[2]   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.

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

[4]   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. While this is welcome, it indicates that full transition is likely to require considerable 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.[5] It found that this bias arose from:

  o a general bias in favour of network capex solutions relative to non-network opex solutions;

  o treating the recovery of demand management opex less favourably than other network opex; and

---

[5] 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.

- distributors generally excluding future 'option value' when considering demand management solutions.

- In submissions to the AEMC's current 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.[6] These views have 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.[7]

After considering this evidence, we note it is likely that distributors presently face incentives to prefer network options to non-network options relating to demand management. This bias manifests itself 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).[8]

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 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

---

6   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.

7   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.

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

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:

- o The demand management services market has limited opportunity to mature, particularly when it comes to providing network support.

- o 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. At a practical level, this will entail:

- Transitioning further towards efficient pricing in distribution networks.

- Monitoring the effectiveness of recent regulatory reforms. For instance, we will require distributors to comply with our ring-fencing guideline by no later than the start of 2018 and oversee metering contestability arrangements that commence in December 2017.

- Progressing further regulatory reforms where required. 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 will require distributors to apply the RIT–D to replacement projects from 18 September 2017.[9] The new 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 by contributing to various rule change proposals and energy market reviews. We will also be carefully considering the views stakeholders present on how we can improve our internal practices, including our 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 to electricity consumers, thereby leading to more efficient outcomes for electricity consumers. In doing so, we anticipate

---

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

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:[10]

> 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.

For the Scheme, we propose a simple mechanism, composed of the following:

- A cost uplift that provides distributors with a clear opportunity to earn a return for undertaking efficient demand management projects. As such, distributors are encouraged to actively seek these opportunities in managing and planning their distribution networks.

- Features designed to moderate this cost uplift so that the level of incentives available to distributors:

  o Takes into account the benefits that demand management delivers to electricity consumers.

  o Is set so that consumers receive a net benefit from the project, even after the distributor has captured the incentive.

  o 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. Following from this, there might be value in changing the uplift we provide under the Scheme.

2.2 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:[11]

> 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 applying the Scheme Objective and principles in NER clause 6.6.3.

---

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

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

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. For clarity, 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. For clarity, 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 another source, including under a relevant distribution determination.

   iii. May vary by distributor and over time.

(e) Penalties should not be imposed on distributors under any 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); 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.

2.3 Stakeholders support a Scheme

For the reasons described in section 2.1 above, we consider that applying a Scheme is the correct course of action.

At our Options Day held on 6 April 2017, we asked stakeholders whether we should apply a Scheme. Overall, there was clear support for the Scheme. Some stakeholders did express the view that the Scheme was unnecessary,[12] but the balance of support was strongly in favour of a Scheme. In submissions after the Options Day, stakeholders cited the 'clear legal and policy intent' of the NER in this regard,[13] alongside the substantive policy process that addressed this question prior to the AEMC rule change, in support of implementing a Scheme.[14]

There was general recognition that the Scheme would be the bridge towards the changing framework, as discussed above in section 2.1. There was also consumer support for paying the cost of the incentive if it would be in their long term interests. Consumer support for the Scheme was succinctly stated in Energy Consumers Australia's (ECA's) submission:

> Effective DM programs by networks are a critical measure to ensure that overall distribution network costs for consumers reduce over time. Distribution Network Service Providers (DNSP) operates like any other business organisation and will respond to the incentives available to them.
>
> Enabling and empowering consumers to manage their consumption and costs, and at the same time contribute to the overall efficiency and stability of the system, is a priority for the National Electricity Market (NEM). Electricity prices have risen significantly in recent years, doubling in some cases; investment in new network capacity has contributed to this increase. Maximising the value extracted from existing infrastructure can avoid further capital investments and contribute to keeping prices lower for consumers.
>
> 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

---

12   AGL, *Additional Submission post demand management options day*, April 2017, p. 1; Australian Energy Council, *Re: Demand management incentive scheme and innovation allowance mechanism: AEC submission following AER workshop*, April 2017; Gill, M, *Response to AER's Options Day discussing the Demand Management Incentive Scheme*, April 2017.

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

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

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 DM investment to be properly assessed.[15]

Section 3 provides further insights from stakeholders, which we have taken into consideration in developing the draft Scheme.

2.4 Demand management in networks

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.

2.4.1 Demand management and peak demand

While distributors build networks to meet peak demand, they only hit their peak for a limited time in the 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.

---

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

Figure 2: Example of a load duration curve
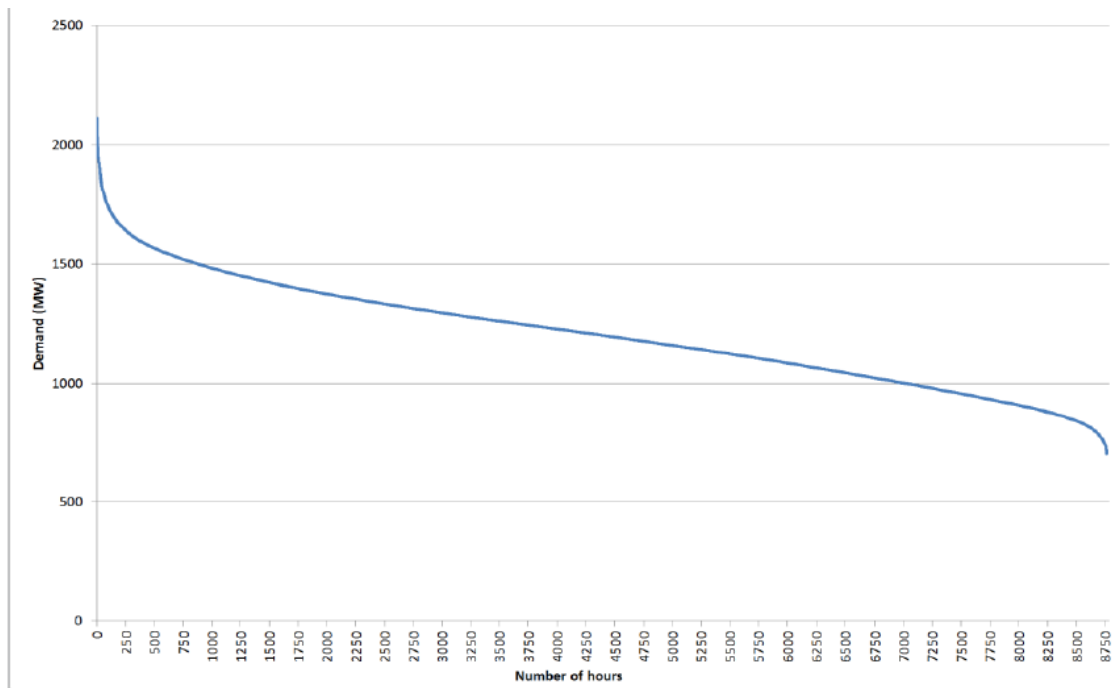
Source: CitiPower/Powercor, *Demand side engagement strategy*, 25 July 2016, v.2.0, Figure 3.2.

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
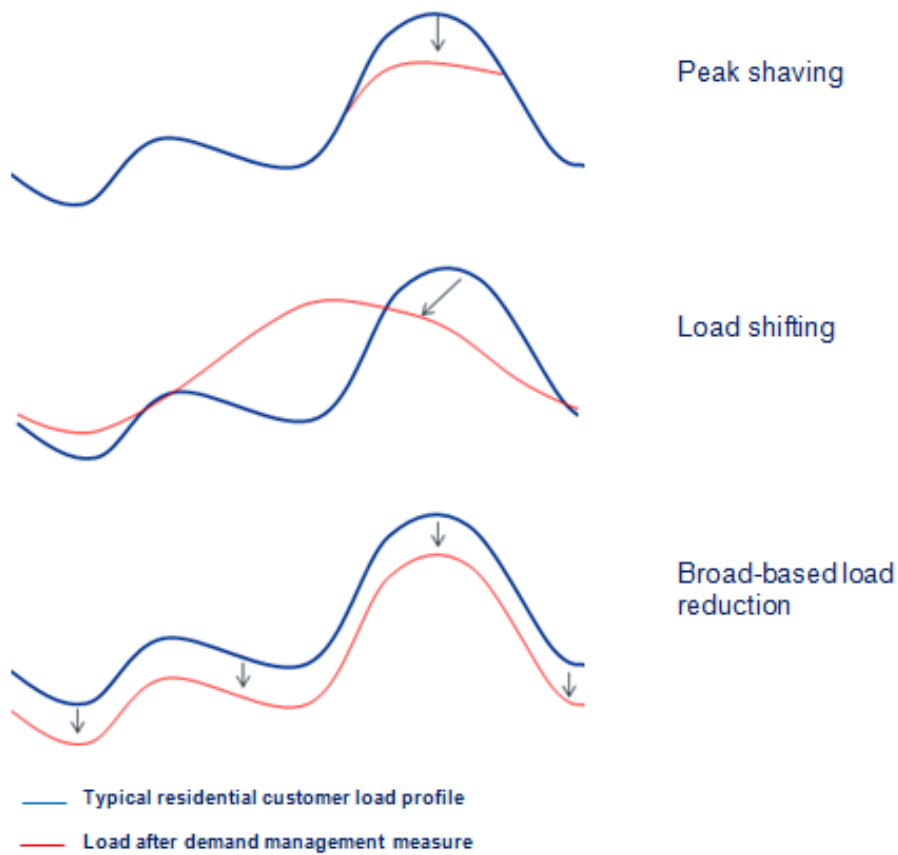
These approaches will typically be implemented by an end-user in practice. To exemplify the differences, direct load control of air conditioning will have a peak-shaving impact, whereas high-efficiency air conditioners will reduce energy consumption whenever the air conditioner is operating.

2.4.2 Emerging uses for demand management

Over the past few years, network demand has flattened and embedded generation has increased. As a result, peak demand has become a less widespread issue, typically only causing network constraints in certain geographic regions. Meanwhile, voltage and power quality issues have been becoming more common. 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, and can defer the retirement or replacement of aging assets.[16]

---

[16]   Ausgrid, *Submission to demand management consultation paper*, 23 February 2017.

- Where there are high levels of intermittent distributed generation, minimum demand can drive network constraints. 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.[17] Minimum demand challenges are expected to become more frequent over time. AEMO forecasts negative minimum demand in South Australia by 2027–28, as it expects rooftop PV will exceed customer demand in some hours.[18]

- 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. As such, these options can have considerable 'option value' or flexibility benefits.[19]

Figure 4: Comparison of strong, neutral and weak scenario forecasts
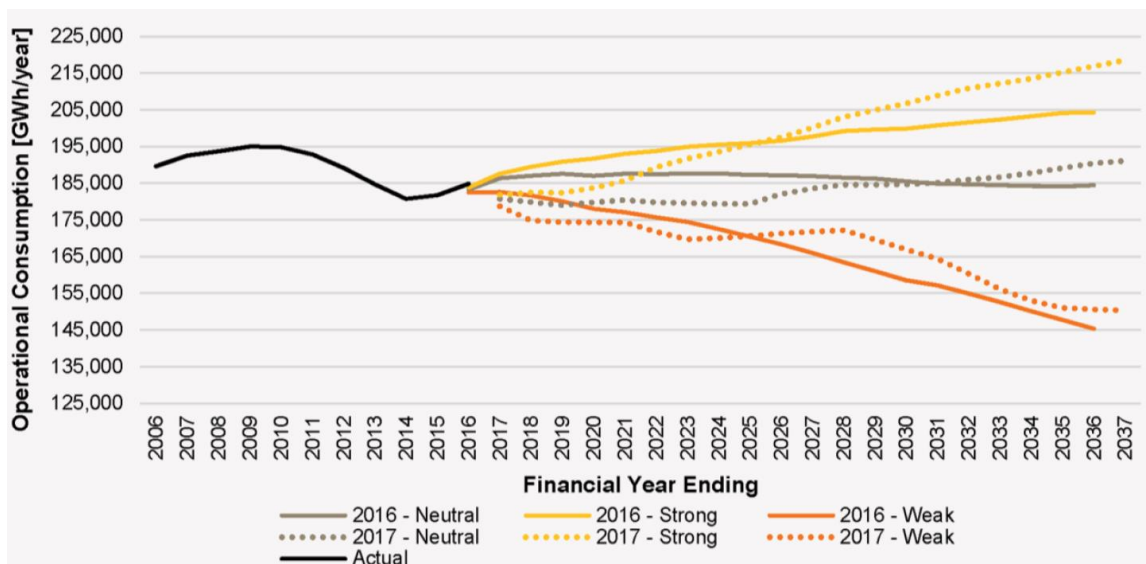
Source, AEMO, *Electricity forecasting insights for the NEM*, June 2017, Figure 2.

2.4.3 Network demand management and other parties

The draft 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.[20] Other or future rules may also narrow the scope of demand management activities distributors can undertake.[21]

- Maximising the expected net benefit of the preferred option. We propose that any eligible project under the Scheme must have the highest expected net benefit across the relevant market, which will often be the NEM.[22] 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 ring-fenced entity (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 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
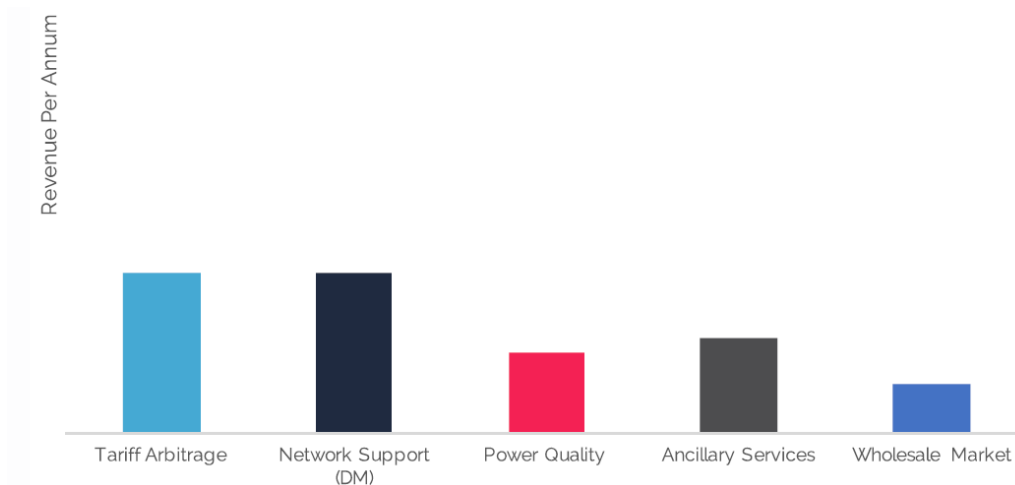
Source: Reposit Power, *Australian Energy Week presentation: Reposit customer grid participation progress update*, June 2017

---

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

[21]   The AEMC is currently consulting on rule change requests from the Australian Energy Council and COAG Energy Council that may affect how distributors may undertake non-network options relating to demand management. See ERC0206: *Contestability of energy services* and ERC2018, *Contestability of energy services - demand response and network support* under http://www.aemc.gov.au/Rule-Changes/Contestability-of-energy-services, http://www.aemc.gov.au/Rule-Changes/Contestability-of-energy-services-demand-response.

[22]   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.

We also recognise that there may be cases where a demand management option has higher controllability when provided in-house. Generation or customer loads that the distributor can dispatch may have higher value if they offer a higher level of firmness or controllability. If a distributor is unable to guarantee dispatch, it would provide this option on an expectation of performance and would probabilistically adjust the value of this capacity.

3 Insights from stakeholders

There has been great stakeholder interest and engagement in this project. The Scheme development process has resulted in a variety of stakeholders sharing their valuable insights. For instance:

- 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.

Where possible, we have made the material that stakeholders have provided to us publicly available on our website.[23]

A diverse range of stakeholders have taken an active interest in this project. While this diversity makes it difficult to summarise the key messages, the following themes emerged:

- As exemplified in figure 6, stakeholder views on the new Scheme and Mechanism are generally positive. This sentiment was also clear at the Options Day. While the majority of stakeholders support the Mechanism as having value, they generally see the Scheme as the 'main game'.

- 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 and while the AEMC is doing work looking into this, there is value in us also looking at this issue. 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'.

---

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

- Expectation among stakeholders for the new Scheme to be operational earlier than the current timeline. Some stakeholders saw value in adjusting the Scheme over time to keep up with market developments.

- A consensus that the Scheme should not include incentives or cost-recovery for supporting infrastructure (such as information and procurement processes/platforms). Information provision too often detracts from the main issue and if we improve distributors' incentives to undertake efficient demand management, then their incentive to provide supportive infrastructure should follow.

- Support for linking incentives under the Scheme to deliverables. Generally, there has been greater support for a percentage uplift to the demand management contract (if out-sourced to another party) or to the project cost (if in-house), where the most efficient project is determined by the market through a competitive procurement process.

- A widely-held view that we should interpret 'demand management' broadly, so as not to limit the Scheme to constraints emerging from peak demand.

- Consumer groups have generally indicated they are willing to fund the costs of the Scheme in the expectation that their initial investment in the Scheme will pay dividends in the long-run through lower overall network charges.[24] They have recognised that the Scheme will deliver a number of benefits to consumers.[25] They have acknowledged that the Scheme aims to encourage demand management that would save consumers money but also avoid further infrastructure development.[26] They see demand management as playing a critical role in the future energy system and support moves to better incorporate as a tool to reduce costs, as well as providing other benefits.[27] While some consumer groups supporting greater use of demand management are hesitant to provide financial incentives to distributors, we consider there is value in doing so for the reasons set out under section 2.1.[28]

---

[24] ECA, *Submission to the AER's development of a Demand Management Incentive Scheme and Innovation Allowance*, June 2017, p. 2.

[25] TEC, *DMIS consultation paper*, February 2017, p. 2.

[26] QFF, *Re: Submission on the Demand Management Incentive Scheme and Innovation Allowance Mechanism, Consultation Paper*, January 2017, p. 2.

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

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

Figure 6: Support for Scheme from submissions on Consultation Paper
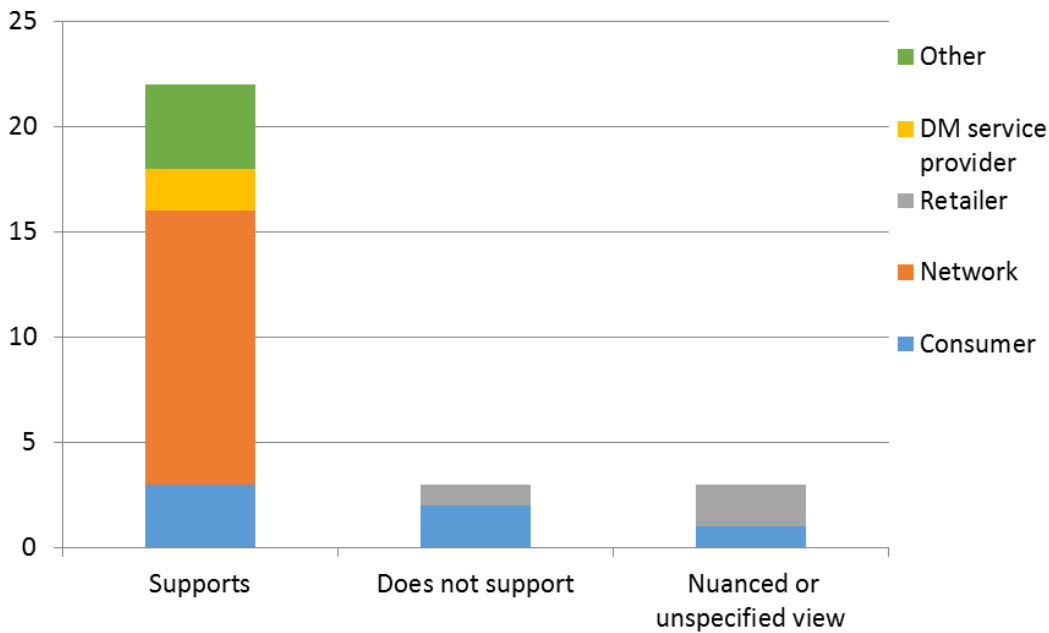
Where possible, we have incorporated the broad themes arising from stakeholders into our draft Scheme so that it achieves the following:

- Provides financial incentives for demand management, but does not include incentives or cost recovery for supporting infrastructure (such as information provision and contract development).

- Provides a percentage uplift to the demand response contract (if out-sourced) or to the project cost (if in-house), where the most efficient project is determined by the market through a competitive procurement process, where:

    o Market-based contracts specify a quantifiable demand management deliverable. The deliverable is a specified kVA per year network demand that can be managed, at the distributor's or other legal entity's request or control.

    o We establish a framework to verify that distributors select projects under the Scheme using a genuinely competitive procurement process (that is, either via the existing RIT-D requirements of the 'minimum project evaluation requirements').

    o We require annual compliance reporting to allow us to compare outcomes across distributors.

3.1 Insights on overall Scheme design

We received a variety of views from stakeholders on the overall design of the Scheme. In our Consultation Paper, we requested stakeholder views on several types of Scheme design options, which we discuss later on under section 9 (see table 6 for a summary of these options).

Based on stakeholder responses to the Consultation Paper, we requested stakeholder views at our Options Day on how we should determine the magnitude of the incentive

and link it to performance. Specifically, we requested views on whether we should design the Scheme in a way that:

- Promoted accountability by requiring distributors to apply competitive procurement practices when identifying eligible projects. Stakeholders were supportive of this design mechanism. Distributors were also supportive as long as it did not preclude them from undertaking demand management projects in-house where efficient and permitted under the ring-fencing guidelines. We have incorporated this into the Scheme design by requiring distributors to identify eligible projects via undertaking a RIT-D or following minimum tendering requirements.

- Attached incentive payments to performance, including in the form of $/kVA of demand management at peak delivered, $/kVA of demand management at peak contracted, or as a percentage of the demand management costs. A percentage uplift of the demand management costs was the most favoured of these options. Several submissions we received following the Options Day reiterated support for this preference, noting benefits such as its simplicity, relatively low administrative burden and flexibility.[29] 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:[30]

> 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.

3.2 Insights on the magnitude of the incentive

To date, we have not had a detailed discussion with stakeholders on a suitable magnitude for the incentive under the Scheme. However, 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 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.

---

[29] 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

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

During the Options Day, a number of stakeholders expressed a preference towards applying an incentive under the Scheme in the form of a cost uplift. Following this discussion, in its supplementary submission, the ISF also suggested an incentive that could be applied in the form of a cost uplift, although an appropriate uplift level would vary depending on which identified need the distributor is considering. It recommended a cost uplift of between 40 and 104 per cent, but also suggested we examine a wider range of case studies and assumptions.[31] In its final report to ARENA, it narrowed its recommended cost uplift range to be between 40 and 90 per cent.[32]

---

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

[32] 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.

4 Application of the Scheme

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

The Scheme will specify that the cost multiplier applied to any eligible project must be that 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 draft Scheme.

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

In the following sections, we explain our decision to:

- Apply the incentive as a cost uplift.

- Set the cost multiplier in the Scheme rather than in the distribution determination or framework and approach (F&A).

- Set the magnitude of the cost multiplier to 50 per cent.

4.1 Applying the incentive as a cost uplift

We considered a variety of possible Scheme designs. Our consideration focussed on three possible designs:

- o The cost multiplier,

- o Net-benefit sharing,

- o Mechanisms to reduce the disincentives to undertake demand management.

We also considered a suite of other options, which also included the possibility of not implementing a Scheme (see section 2.3). Following our deliberations, we considered the above three options were the most viable for achieving the Scheme Objective.

4.1.1 The cost multiplier

The cost multiplier consists of an uplift on the costs of demand management projects. This provides distributors with an incentive to undertake efficient projects, as they receive a return on demand management costs.

Following our consultation and guideline development 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. Relative to net benefit sharing, as a starting point for the Scheme we consider that it provides a high degree of certainty to distributors when committing projects, imposes a relatively modest administrative burden, and provides an adequate financial incentive.

We recognise that there are drawbacks to this approach (see section 4.3 for a discussion). We have also designed the Scheme so that only efficient projects are eligible to receive an incentive. Further, our net benefit constraints provide safeguards to ensure that consumers receive the economic benefits. Moreover, as discussed in section 4.2 we have set the cost uplift in the Scheme so that we can adjust it over time based on its effectiveness and benefits.

4.1.2 Net-Benefit Sharing

A net benefit sharing mechanism would entail calculating the benefits of a given demand management project in the relevant market and providing distributors with some portion of that benefit as an incentive. The concept of net benefits is integral to our implementation of the cost multiplier, as described in section 6.2. However, our chosen Scheme design acknowledges the bounds of our current understanding of the net benefits of demand management.

A precise calculation of the benefits involved would provide customers with a more certain value proposition. Oakley Greenwood advocated such an approach in their commissioned report as its first preference, as did the ISF in its submission on the Consultation Paper. Some distributors also considered that we should adopt such an approach. We agree that in theory this approach should provide the greatest value to customers and the broader market. Given the stakeholder support, we gave this option considerable thought.

However, in practice, such a sharing Scheme faces difficulties at this time. Such calculations are sensitive to the inputs and assumptions made by the entity performing the calculation. 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-solutions with increasing pace.

In our view, there is a limited understanding of demand management's market-wide benefits, and calculating these benefits can be difficult. While Oakley Greenwood provided us with some worked examples for calculating certain benefits associated with demand management, these required employing approximation methods and assumptions.[33] 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.

---

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

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 uplift. Moreover, the cost uplift 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 use of the RIT-D, which encourage the public sharing and scrutiny of the net benefit calculations used by distributors. We consider that overtime this will lead to a greater market understanding of how to calculate the benefits of demand management.

Additionally, calculations of net-benefit cannot address potential non-financial barriers to demand management, such as a cultural bias among distributors. The cost uplift 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.

The draft Scheme also contains several measures intended to moderate the size of the incentive, while providing a healthy incentive that we consider will encourage distributors to engage in projects where they are efficient. To be eligible for an uplift the net benefits of projects must have been assessed, and this assessment will inform (but not alone determine) the size of the incentive. 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.

4.1.3 Removing disincentives to undertake demand management

Throughout both the AEMC rule change process and our own consultation, we considered exempting demand management projects associated with the Scheme from other schemes, such as the Service target performance incentive scheme (STPIS), the Efficiency benefit sharing scheme (EBSS) and the Capital Expenditure Sharing Scheme (CESS).

However, STPIS exemptions may also expose consumers to more risk, by placing the risk of project unreliability on them. We consider that distributors are better placed to mitigate these risks, and therefore should bear the costs associated. We also consider that 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.

With regard to the CESS and EBSS, we consider that the symmetrical operation of these incentives will balance out any negative impacts that distributors may experience. As distributors spend more on opex, they may exceed their targets under the EBSS. However, commensurate savings in capex gained from project deferral should provide them with gains under the CESS. We therefore see no reason to alter the operation of these incentives.

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 F&A 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 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 to assess the effectiveness of any demand management investment.[34] 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 and 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.

4.3 The magnitude of the cost multiplier

The draft 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

---

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

regulatory framework is evolving to better facilitate efficient investment decisions, we consider an upwards movement unlikely.

- 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' cost multiplier would be calculated on a project-specific basis. However, we nevertheless consider that 50 per cent is a reasonable cost-multiplier to apply as a starting point for the Scheme as it is:

- On the lower side of the ISF's suggested cost uplift range of between 40 and 104,[35] or 40 to 90 per cent.[36]

- Consistent with the magnitude of 25 or 50 per cent that GreenSync proposed in its submission to our Consultation Paper.[37]

- Higher than the cost uplift suggested in United Energy's supplementary submission following the Options Day that equated to the nominal vanilla WACC on a one-off basis.[38]

- Higher than the cost uplift Oakley Greenwood recommended we apply to the three projects it considered —which would be 7.4, 8.4, and 26.5 per cent.[39] However, it 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 uplift.

---

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

[36] 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.

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

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

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

- Equivalent to receiving an allowed rate of return of 6.3 per cent compounded semi-annually over approximately 6.5 years.[40] 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

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

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

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

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

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

---

[40] 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.

5 Identifying and committing eligible projects

Clause 2.2 of the draft Scheme defines the type of projects that the Scheme 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 rules, 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 that we should not add requirements where existing processes, like the RIT-D, already address the relevant issue. For details relevant to how we the specified 'minimum project evaluation requirements', see section 5.2.
It is efficient if it is a credible option to meet an identified need on the distribution network, where that credible option is the preferred option.	Adopting the term 'preferred option' used in the RIT-D: • Streamlines the assessment process with the RIT-D. • 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.	This position is consistent with many stakeholders' views that support efficiency assessments at the network planning stage.[41] While some stakeholders caution against quantifying broad market benefits, others specifically supported this approach.[42] We consider this analysis necessary to deliver the NER's intent, but note it can also be complex, costly and subjective. We have therefore developed some worked examples using 'rule of thumb' approaches to estimating broad market benefits.

---

[41] 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.

[42] 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.

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' so that the network constraint need not be only 'at peak'.
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.

The next sections elaborate on the following elements summarised in table 1:

- Using a broad definition of 'demand management'; and

- Defining 'minimum project evaluation requirements'.

5.1 Defining demand management

As discussed in table 1, projects eligible for financial incentives under the Scheme must be non-network options relating to demand management. In applying this criterion, we have taken a broad view of demand management on the distribution network as the act of modifying the drivers of network demand to remove a network constraint. This definition differs from a narrower view we previously considered that was specific to removing network constraints *at peak*.

We decided to remove the reference to 'at peak' from our definition of demand management because of the following:

- Restricting the definition of demand management to peak demand issues would limit the relevance of the Scheme and prevent it from being dynamic —particularly when peak demand reduction is becoming a smaller part of demand management.[43]

- In particular, networks' demand management is more likely to address constraints that are not driven by peak demand. For instance, in Ausgrid's network, peak demand drives few constraints, but demand management nevertheless has value in meeting its need for redundancy support. For instance, demand management can address risks associated with equipment failure, and thereby add value when deciding whether to defer the retirement or replacement of aging assets.[44]

- SA Power Networks expressed the importance of incentivising the use of demand management in addressing constraints associated with minimum demand, as well

---

[43] At the Directions Forum, a number of stakeholders expressed this view; including representatives from AEMO, Ausgrid, the ENA, Pooled Energy, SA Power Networks and TasNetworks.

[44] Ausgrid, *Submission to demand management consultation paper*, 23 February 2017.

as peak demand.[45] It noted that some of the technical challenges associated with minimum demand concern network voltage and system frequencies, and noted that these challenges will present key opportunities.[46] Energex also identified value in designing the Scheme to encompass emerging issues such as voltage and power quality management issues.[47]

- The Australian Energy Market Operator (AEMO) submitted that the Scheme would miss many opportunities to drive customer benefits if it has a narrow focus on using demand management to offset peak demand. It discussed the benefits of the Scheme being broad enough to also focus on downsizing/deferring replacement expenditure, managing diverse power flows, flexibility under uncertain demand and grid support services to maintain system security.[48]

Recognising these benefits, the draft Scheme does not restrict demand management to addressing peak demand. However, in taking a broader definition, we are also aware of the following:

- Some stakeholders saw value in tying incentives to peak demand in their submissions on our Consultation Paper.[49] Oakley Greenwood also advised that in most cases, a distributor's underlying augmentation cost driver will be either co-incident peak demand or energy at risk. It advised that for this reason, $\$/kVA$ of demand management would be an appropriate metric for delivering incentives under the Scheme.[50]

- Expanding the definition potentially increases the complexity of tying incentives to performance. For instance, if we tied incentives to peak demand reductions, we could deliver the incentive in the form, $\$/kVA_{peak}$. However, this form is difficult to apply if we take a broader approach, which leads us to either provide an incentive:

  o based on a broader measure, such as a percentage uplift on the costs of demand management (as we have in the draft Scheme); or

  o in potentially multiple forms, varying between whether the demand management addresses issues relating to peak demand, voltage control, or some other factor.

While the above factors may cause difficulties, we also consider there is value in implementing a Scheme that is adaptable to changing market conditions and recognises that demand management can add value outside of peak demand management. Moreover, we consider we can apply a broader definition whilst maintaining many of the benefits to the $\$/kVA_{peak}$ approach by:

---

45   SA Power Networks, *Submission to demand management consultation paper*, 24 February 2017.

46   SA Power Networks, *Supplementary note following demand management options day*, 21 April 2017.

47   Energex, *Submission to demand management consultation paper*, 24 February 2017.

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

49   For example, see ISF, *Submission to demand management consultation paper*, 27 February 2017; PIAC, *Submission to demand management consultation paper*, 24 February 2017.

50   Oakley Greenwood, *Advice on the DMIS incentive prepared for: AER*, 23 June 2017, p. 11.

- Applying the financial incentive on a broad measure (percentage uplift on the cost of demand management), so the Scheme does not become prohibitively complicated and administratively burdensome.

- Capping any eligible project's incentive at its expected net benefits, so the financial incentive has a basis in the project's benefits.

- Requiring the distributor to set deliverables when it commits to a project. For example, when a distributor contracts demand management services, it must write these deliverables into the contract (see sections 5.3.1 and 5.3.2 on the rationale for requiring demand management contracts and proposals).

The aim of these measures is that projects deliver net benefits and measureable deliverables for consumers. We require distributors to identify and quantify what a project will deliver, make benefit calculations on this basis and then cap the incentive based on the calculated benefits. We consider that this creates an identifiable metric for success, and then places limits on the incentive in line with this metric, meaning that customers and the broader market will receive value and that we will be able to identify and communicate this value. The result of this process will likely be a market that is informed about the costs and benefits of demand management, which we consider a more effective market. This feature will also assist us in determining the effectiveness of the scheme through compliance procedures laid out in Section 7.

5.2 Defining minimum project evaluation requirements

Subclause 2.2.1 of the draft Scheme sets 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 make a commitment to the demand management component of that non-network option. Committing a project includes contracting or signing off on the costs and deliverables of the demand management (see section 5.3).

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

5.2.1 Issuing requests for demand management solutions

When following the minimum project evaluation requirements in the draft 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.[51]

- Any other parties the distributor may identify as having or potentially having the capabilities to provide 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.

We consider it 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.[52]

5.2.2 Information in the request for demand management solutions

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

- Key technical information, including the load at risk, energy at risk, duration and load curves, and the annual probability and frequency of events.

- The location of the identified need and the impacted customers/network area.

- The project it has identified as its preferred option to meet the identified need on its network. This includes its estimate of the project's net economic benefit to all those who produce, consume and transport electricity in the relevant market. It must estimate a project's net economic benefit as the net present value (NPV), which must be positive unless the project is for reliability corrective action.

- 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.[53]

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.

---

[51]   NER cl. 5.10.2.
[52]   NER, 5.17.4.
[53]   NER, 5.17.4(e).

The draft 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 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.[54]

NER 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 the RIT-D proponent considers 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:
    o the size of load reduction or additional supply;
    o location;
    o contribution to power system security or reliability;
    o contribution to power system fault levels as determined under NER cl.4.6.1; and
    o the operating profile.

- A summary of potential credible options to address the identified need, as identified by the RIT-D proponent, including network options and non-network options.

- For each potential credible option, the RIT-D proponent must provide information, to the extent practicable, on:
    o a technical definition or characteristics of the option;
    o the estimated construction timetable and commissioning date (where relevant); and
    o 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 for consideration by the RIT-D proponent.

---

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

5.3 Requirements for committing projects

The draft 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 request or control. It may also be at the other legal entity's 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 request or control; or

- A 'demand management proposal', but only if and where the distribution ring-fencing guidelines 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 control network demand. The proposal must specify the amount of demand the distributor can 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 it commits to a project because this provides greater assurance that we are linking incentives under the Scheme to demand management deliverables.

5.3.1 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.

Under the draft Scheme, we propose to provide the distributor with discretion on how to structure payments for availability versus dispatch under a demand management contract. However, the expected costs of this contract must align with the unit prices and its probabilistic assessment of future demand.

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 the one year would be $720,000.

Example 1 provides a simple illustration of expected costs under a demand management contract. A distributor might structure a contract with another legal entity differently to this. However, the draft Scheme specifies that 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.

5.3.2 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 guidelines; 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 draft Scheme (and explained in section 5.2 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 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 draft Scheme, without a demand management proposal compliant with the Scheme, an in-house option will not be recognised as a committed project and therefore ineligible for project incentives.

6 Determining the project incentive

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

A distributor must calculate the project incentive as the lower of the two values:

- The expected present value at time t of the project's demand management costs, multiplied by the cost multiplier $d_1 = 50\%$. These expected demand management costs must be consistent with:

    o The costs of the demand management solution in the distributor's demand management contract or proposal.

    o The distributor's reasonable expectation of the frequency and duration on which it will call on or utilise its capability to control demand under the demand management contract or proposal. That is, the distributor would need to determine probabilistically the demand it expects to 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 calculate this expected net benefit in accordance with the guidance for applying the cost–benefit analysis under the RIT–D. In doing so, the distributor must estimate the project's net benefit relative to the 'base case' where:

    o the distributor does not implement a credible option; or

    o only if the identified need is for reliability corrective action, the distributor's preferred network option.

6.1 Percentage of expected demand management costs

This section explains why we base the project incentive on expected demand management costs. For information on why we base the project incentive on a percentage of 50 per cent (the cost multiplier), see section 4.3.

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.

Under the draft Scheme, the project incentive is based on expected costs—that is an ex-ante probabilistic assessment of what the distributor expects its efficient demand management costs will be. An ex-ante project incentive is 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.

- Incentive regulation, where we determine distributors' maximum allowed revenues based on ex-ante assessments of efficient costs.

6.2 The net benefit constraint

Under the draft 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.

A distributor must calculate the expected net benefit consistently with the guidance for applying the cost–benefit analysis under the RIT–D.[55] 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 distributor's preferred network option.

The following sections explain our rationale for:

- Including a net benefit constraint; and

---

[55] That is, consistently with AER, *Final: RIT–D*, 23 August 2013 and the supporting document— AER, *Better regulation: RIT–D application guidelines*, 23 August 2013.

- Requiring distributors calculate net benefits relative to a 'base case' as specified above, and consistently with the cost–benefit analysis under the RIT–D.

6.2.1 Why include a net benefit constraint?

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.[56]

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. The illustrative example in table 4 highlights what effect a binding net benefit constraint could have on a project incentive. In the hypothetical scenario presented in table 4, 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 draft 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 draft Scheme to satisfy the principle in the NER to deliver net cost savings to retail customers.

Table 4: 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	$\min\{10 \times 50\% = 5; \ 2.5\} = 2.5$

6.2.2 Why calculate net benefits consistently with RIT–D?

The draft Scheme requires distributors to calculate the net benefit constraint consistently with the cost–benefit analysis under the RIT–D. This promotes consistency with how the distributor has already identified projects considered 'efficient' under the draft Scheme—that is, projects it has evaluated as a 'preferred option' (as referred to in NER chapter 5). For further explanation, see table 1.

Also, a distributor must estimate its project's net benefit relative to a 'base case' where it does not implement a credible option, or where it implements its preferred network option (but only if the identified need is for reliability corrective action). 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. This is consistent with the RIT-D, which does not require the base case for

---

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

calculating net benefits to be a do-nothing option where the identified need is for reliability corrective action. As such, the draft Scheme requires the 'base case' be a do-nothing option unless the project is for reliability corrective action; in which case it must be the network option with the highest net benefit.

7 Compliance reporting

Clause 2.4 of the draft 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 draft Scheme also lists the project-specific data the distributor must report.

The distributor must include data pertaining to expenditure incurred in the past regulatory year for which it is seeking incentives. 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 the demand management to have realised.

The distributor must also include data on any eligible project it committed in the past regulatory year, including:

- The total financial incentive the distributor accrued, based on the project incentives it accrued from the projects it committed that year. Reporting on this allows us to validate the total financial incentive.

- Listing the identified eligible projects, as well as their expected costs and benefits. This information allows us to understand the 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.[57] This information should include a description of these proposed projects, as well as their proposed costs, deliverables and estimated net benefit. 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

---

[57] 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 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).

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 or control and expects to dispatch or control, based on its probabilistic assessment. This information should assist us in:

    o Understanding the assumptions distributors apply in assessing demand management options in their cost-benefit analyses.

    o Projecting the Scheme's impact in subsequent financial years.

7.1 AER use of compliance report

Within nine months of the completion of the regulatory year to which that compliance report pertains, we will validate the pass through of the incentive payment 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.[58]

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 guidelines, 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 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.

---

[58] 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 incentive payment.

- 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 guidelines.

- Utilising demand management in different ways to meet their unique network needs.

8 Accruing and applying the financial incentive

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

- The total financial incentive accrued to a distributor in any regulatory year cannot exceed 1.0 per cent of the distributor's revenue requirement for that regulatory year.

- We incorporate the total financial incentive into a distributor's revenue requirement with a two-year lag.

- The total project incentive accrues to distributors on an ex-ante basis.

8.1 Total financial incentive cap requirement

The draft Scheme caps 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.

We have decided to include a cap to protect retail customers from the possibility of bearing costs under the Scheme that are unexpectedly high.[59] 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 draft Scheme proposes a uniform incentive (a demand management cost uplift of 50 per cent),[60] which we consider a reasonable magnitude for projects on average (but not necessarily at an individual-project level).[61]

- 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 project that do not deliver net cost savings to retail customers. For instance, Energy Consumers Australia's support for providing financial incentives under the Scheme is contingent on networks 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.[62] While the Scheme should hopefully support these activities, there are always risks in designing and implementing a new incentive scheme or regulatory mechanism.

---

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

[60] Subject to the net benefit constraint.

[61] 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.

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

We consider 1.0 per cent of the revenue requirement 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.[63]

- As illustrated in table 5, allows distributors to receive a total incentive on their efficient demand management costs of up to approximately $1.2–15.1 million per year, depending on the size of the distributor. We are of the view that this is:

  o Substantial enough to incentivise distributors to actively explore demand management opportunities, where efficient to do so, as a competitive solution against supply-side options.

  o 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.[64]

  o Unlikely to be too restrictive. 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. As such, there is merit in revaluating the 1.0 per cent cap after observing the Scheme's impact on encouraging network-level demand management.

Table 5: One per cent allowed revenue in recent year ($ mil)[65]

Distributor (2015–16)	1.0% of allowed revenue	Distributor (2016)	1.0% of allowed revenue
ActewAGL Distribution*	1.22	AusNet	5.86
Ausgrid*	15.07	CitiPower	2.83
Endeavour Energy	8.04	Jemena Electricity	2.38
Energex	11.40	Powercor Australia	6.22
Ergon Energy	11.38	United Energy	3.75
Essential Energy	9.11		
SA Power Networks	6.82		
TasNetworks*	2.87		

* Distribution assets only.

---

63 AER, STPIS version 5 (corrected), October 2015, clause 5.3(a).
64 Consistent with NER cl. 6.6.3(c)(4)(i).
65 Figures based on AER final decisions before appeals to the Australian Competition Tribunal.

8.2 Applying total financial incentive with a two year lag

Clause 2.6 of the draft Scheme describes our process for including the total financial incentive in the distributor's annual revenue requirement. 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 allowed revenues via its annual pricing proposal process. A two-year lag is also consistent with the lag we apply to the current demand management innovation allowance, which is also for pragmatic reasons (given the time lag in data collection and assessment).[66]

Figure 7, which also appears in the draft 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 five months after receiving the compliance information. At this time, the distributor incorporates the total financial incentive into its pricing proposal.

- 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.

8.3 Incentive accrues on an ex ante basis

Under the Scheme, a distributor accrues the incentive on project costs before it incurs those costs. We consider that ex ante accrual has several benefits as it delivers greater certainty and a low administrative burden. By allowing the incentive to accrue up front, we consider that distributors are more likely to make investments, as there is greater certainty about the size of their return. This is valuable, given the consistent feedback from stakeholders indicating that a regulatory framework that supports investment in demand management is essential, given the developing nature of the demand management market.

An alternative approach we considered was to cap the incentive based on expected costs but deliver the incentive on actual costs over the life of the project. This approach would smooth the incentive payment over the life of the project based on actual costs, but would require significant resources to reconcile with the ex-ante cap and track payments, potentially over a long period.
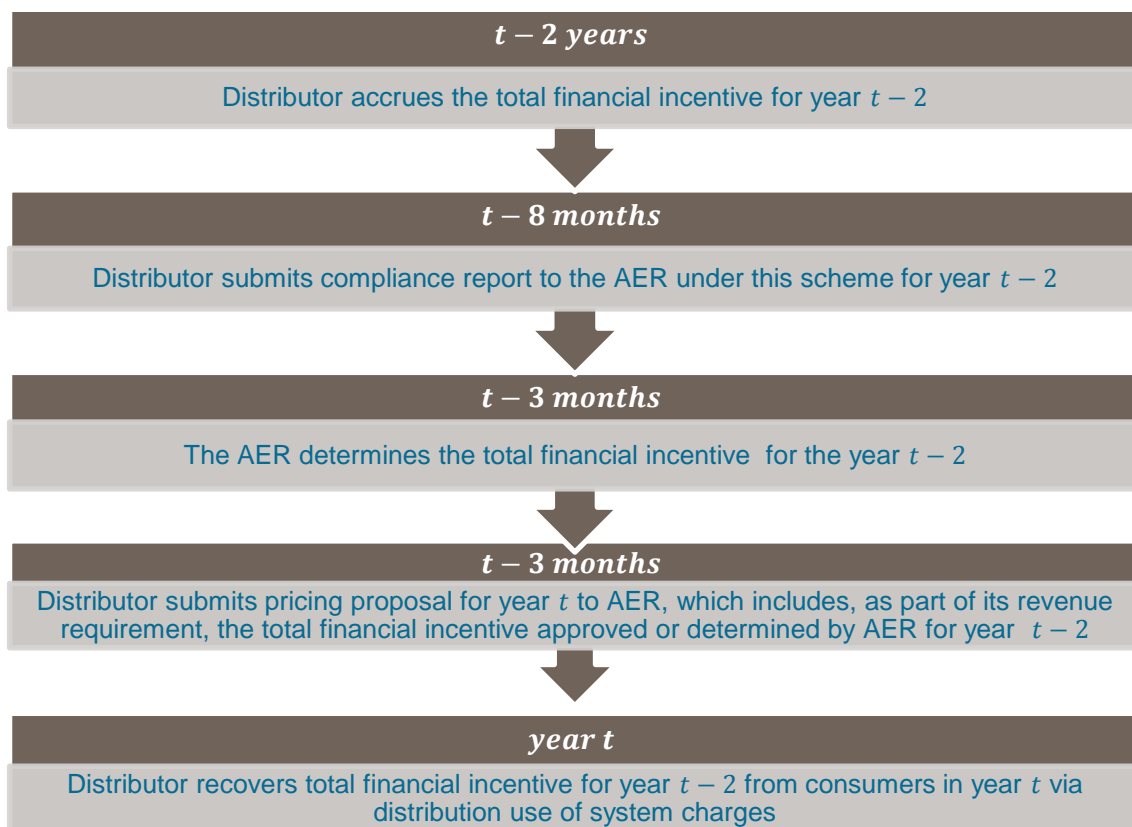
---

[66] Currently, we deduct (add) the final carryover amount from the previous regulatory control period from (to) allowed revenues 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.

Were we to base the incentive on actual costs over the life of the project, there may be less certainty about the return. This may lead distributors not to investigate potentially efficient options and the incentive would therefore be less effective in overcoming the barriers faced by demand management. However, the actual costs payment approach could allow consumers to gain from demand management cost underspends.

Accruing the incentive ex ante also has the benefit of a low administrative burden. In 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. Other measures, such as paying the incentive ex post but within a set number of regulatory control periods, would only have a marginal impact on lowering the administrative burden. Moreover, it is unclear how best to identify and limit the periods. This marginal benefit would, in our view, still exclude useful, forward thinking projects that will help to achieve the Scheme Objective.

On balance, to start the Scheme, we consider the ex ante accruing of the incentive on project costs will better achieve the Scheme Objective at this time.

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 the AER under this scheme for year $t - 2$

$t - 3\ months$

The 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 revenue requirement, 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

9 Elements considered for the draft Scheme

Table 6 summarises the different incentive mechanisms we consulted on as potential options in our Consultation Paper. It also summarises whether or how we have applied these options in the draft Scheme.

Table 6: Mechanisms considered for the draft Scheme

Incentive mechanism consulted upon	Incorporated into the draft Scheme?
Mechanisms to target potential disincentives: Limiting penalties under the service target performance incentive scheme (STPIS).	No, for the reasons set out in section 9.1.
Mechanisms to target potential disincentives: Excluding demand management research and development from the opex building block.	We incorporate this mechanism, but as a feature of the Mechanism rather than the Scheme.
Mechanisms to target potential disincentives: Incentives to help place capex and opex on a more equal footing, including: • Demand management cost uplift; • Return equivalent to foregone return on and of capital over one or two regulatory control periods; • Financial uplift on demand management proportional to option value; • Link projects under the Mechanism to the Scheme by providing an 'innovation return bonus'; and/or • Extending the recovery of foregone revenue mechanism to ActewAGL, which is under an average revenue cap.	• Yes, the draft Scheme is based on a demand management cost uplift. • Distributors will consider the costs associated with competing network capex options when calculating the net benefits. • Distributors will consider demand management's option value when calculating net benefits. • Introducing demand management cost uplifts should already increase distributors' incentives to commercialise research and development under the Mechanism. • Recovery of foregone revenue is no longer relevant as we are moving ActewAGL to a revenue cap.
Net market benefit sharing mechanism	Not in the form presented in the Consultation Paper. However, distributors calculate net market benefits when selecting the credible option with the highest net benefit across the relevant market. The net benefit calculation affects both project selection and the level of incentive a distributor can receive under the draft Scheme.
Mechanism to promote competition: Incentivising distributors to provide information	No, for the reasons set out in section 9.2.
Mechanism to promote competition: Bidding mechanism to encourage market delivery	Not in the form presented in the Consultation Paper. However, we require distributors to subject all eligible projects under the Scheme to competitive testing.
Targets for demand management deployment	No, for the reasons set out in section 9.3.

In this section, we explain why we did not incorporate the following mechanisms into the draft Scheme:

• Limiting penalties under the STPIS;

• Incentivising distributors to provide information; and

• Demand management targets.

9.1 Limiting STPIS penalties

In our Consultation Paper, we discussed the possibility of limiting penalties associated with demand management projects under the STPIS.[67] For instance, when estimating the reliability component under the STPIS, we suggested that we could possibly exclude a defined number of network interruptions associated with unexpected underperformances of demand management projects.

We have not incorporated STPIS exclusions into our draft Scheme for the following reasons:

- These would not produce benefits if the STPIS is balancing incentives as intended. We do not consider the STPIS creates a perverse incentive against demand management. Moreover, if evidence suggested otherwise, it would be suitable to address such a problem via amending the STPIS directly — particularly as we are currently reviewing our STPIS.[68]

- To the extent some distributors perceive demand management options to be less reliable than network options, we do not support addressing these perceptions with STPIS exclusions because:

  o Exclusions could further embed the perception that demand management options are less reliable than network options.

  o Distributors' inexperience in providing demand management relative to network solutions would have likely influenced this perception. As such, creating a Scheme that incentivises distributors to undertake more demand management where efficient should already go some way in addressing this inexperience.

  o STPIS exclusions could skew distributors' incentives towards undertaking relatively unreliable demand management projects. These skewed incentives could incentivise a number of unreliable demand management options, which would further embed the perception that demand management is unreliable.

Stakeholders generally showed little support for providing exemptions to the STPIS. Submissions to the Consultation Paper provided reasons against this approach, including:

- United Energy advised against excluding demand management solutions from the STPIS as doing so may compromise the intended network reliability associated with these solutions, resulting in customers paying for a service they may not be getting.

---

[67] AER, *Consultation paper: Demand management incentive scheme and innovation allowance mechanism*, January 2017, p. 36.

[68] For information on our current review, see AER, STPIS 2017 amendment, https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/service-target-performance-incentive-scheme-2017-amendment.

- Ausnet Services, CitiPower and Powercor saw STPIS exemptions as a distortion that transfers risk of poorer reliability onto consumers. Origin Energy also felt these exemptions would be inefficient and inequitable.

- Ergon Energy submitted that we should limit considering STPIS changes to our STPIS review rather than under the Scheme.

- SA Power Networks submitted that we should leave service underperformance risks for distributors to manage flexibly, depending on the prevailing circumstances.

- The ISF advised that instead of making a special dispensation within the STPIS for demand management underperformance, we should encourage distributors to implement normal risk management strategies and avoid passing disproportionate risks onto demand management service providers.

While some stakeholders supported STPIS exemptions in their submissions to our Consultation Paper,[69] these positions appeared to fall away in the Options Day and the following consultation steps.

9.2 Incentivising distributors to provide information

An option discussed in our Consultation Paper entailed incentivising distributors to develop (where necessary) and publish timely information in accessible formats to better facilitate other legal entities in providing demand management services.[70] In our Options Day presentation, we broadened this option to include providing incentives or allowing for cost-recovery of 'supporting infrastructure'. 'Supporting infrastructure' referred to infrastructure to support the development of an effective demand management market, including by allowing cost recovery for developing:

- Standard form contracts;

- Procurement processes/platforms; and/or

- More effective systems for provide information to the market.

Providing cost recovery of supporting infrastructure or incentivising distributors to provide information are not features of our draft Scheme. This option received very little support from stakeholders at the Options Day. In principle, we agree with the view that if we improve distributors' incentives to undertake efficient demand management, then their incentive to provide supportive information and procurement infrastructure should follow. We also acknowledge that several stakeholders at the Options Day felt that information provision had too often detracted from the main issue— the balancing of distributors' incentives.

---

[69] Some stakeholders appeared to support this option in their submissions to our Consultation Paper, including Jemena, AGL (to some extent), Endeavour Energy, Energex and the Energy Efficiency Council.

[70] AER, *Consultation paper: Demand management incentive scheme and innovation allowance mechanism*, January 2017, pp. 44–45.

Moreover, we have recently published a Distribution Annual Planning Report (DAPR) template.[71] The DAPR template should encourage distributors to provide information in a more accessible and timely format, independent of the Scheme as it aims to improve:

- Consistency and useability of DAPRs across the NEM.

- The ability for non-network providers to identify and propose solutions to addressed identified network needs.

It is a living document, which will evolve in response to stakeholders' needs in a timely manner. It includes, among other information:

- The name and location of network assets where a limitation has been identified;

- The timing of the limitation;

- The proposed solution;

- The estimated cost; and

- The amount by which peak demand would need to be reduced to defer the proposed solution and the dollar value of each year of deferral.

9.3 Setting demand management targets

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.[72] We recognised that demand management targets would be difficult to implement as these would require setting baseline peak demand targets. We would also have to make 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.

We have not based the draft Scheme on demand management targets. We are satisfied that a target-based Scheme would be difficult to implement in a way that would achieve the Scheme Objective to incentivise distributors to undertake efficient non-network options relating to demand management. Specifically, it would require us to set a target level of demand management that was 'efficient', which would be difficult for us to set. Rather, we consider it preferable for the distributor to assess efficiency at the project-level when network planning.

Stakeholder submissions to the Consultation Paper generally emphasised the difficulties with implementing a target-based Scheme that would encourage efficient expenditure. We generally accept the following submissions:

---

[71] AER, *Final decision: DAPR template version 1.0,* June 2017.

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

- 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, SA Power Networks and the 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 the 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 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.

While some stakeholders supported demand management targets in their submissions to our Consultation Paper,[73] this position appeared to fall away in the Options Day and the following consultation steps.

---

[73] 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 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.

A Calculating net benefits and approximating option value

The net benefit calculation has the same purpose as the RIT–D, as set out at cl. 5.17.1(b) of the NER. This 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.

As such, distributors should refer to the RIT–D and its application guidelines for guidance in performing the net benefit calculation.[74] In particular, Attachment A of the RIT–D application guidelines provides specific guidance and worked examples on valuing classes of market benefits.[75] This guidance includes a worked example of quantifying changes in costs to other parties as a market benefit.[76]

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.[77] When determining the net benefits for non-RIT-D projects, there may be value in distributors applying simplified approaches to quantifying particular costs or benefits where appropriate and reasonable.

In particular, 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.[78] For example, SA Power Networks only supported internalising option value if the calculation could be simple.[79] Also, Endeavour Energy requested we provide guidance if we were to internalise option value in the Scheme.[80]

---

[74] 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.

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

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

[77] 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.

[78] 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.

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

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

While option value can be complex to calculate, Oakley Greenwood recommended a method that it considered would be reasonable for approximating option value. In section A.1, we set out Oakley Greenwood's suggested method as a potential means to approximate option value.[81]

We are interested in stakeholder views on this approximation method, and whether stakeholders would find it useful for us to include this approximation method in the explanatory statement for our final Scheme.

We have put Oakley Greenwood's approximation method forward because option value is a key benefit that can be provided by demand management options. The option value benefit arises because demand management projects have relatively low sunk costs. Various stakeholders have recognised that demand management has high option value, which is often undervalued.[82]

Demand management can provide particularly high option value to distributors when load forecasts are uncertain, by allowing them to see how load develops. Distributors can then make more informed decisions regarding whether to invest in a supply-side option (or to what scale it should invest). That is, by building capacity to manage demand (for instance, by having demand response on standby or by building the capability to directly control load), distributors can generate the option to support the network if needed. This option is essentially akin to an insurance policy. AEMO recognised this point in submitting that:[83]

> The decision to invest in network infrastructure is relatively straightforward if demand for electricity network services consistently grows. Historically, network planners have been confident that network infrastructure will ultimately be used, even if their demand forecasts are not quite right. Over the decade, this assumption has ceased to hold true.
>
> There is now more scope to consider alternatives to expensive, lumpy network upgrades. Demand management options have the potential to be more cost effective and flexible in circumstances where it is unclear whether an identified constraint is likely to persist. Having a scheme that appropriately incentivises businesses to invest in projects that are more flexible to declining (or uncertain) demand conditions will mean there is a less likelihood of future stranded assets.

---

[81] This approximation method is also explained and illustrated in Oakley Greenwood, *Advice on the DMIS incentive prepared for AER*, 23 June 2017.

[82] 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.

[83] AEMO, *Demand management incentive scheme and innovation allowance mechanism*, 24 February 2017, p. 3.

A.1 Method for approximating option value

We sought advice from Oakley Greenwood, which suggested a distributor should calculate option value to reflect:

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

- 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.

While option value can be complex to calculate, Oakley Greenwood recommended a method by which it can be approximated. This approach entails calculating option value as the difference between the cost of the asset the distributor is proposing based on its 50 probability of exceedance (POE) planning criterion and the cost of the assets it would need to build if the forecast were to develop very differently.[84]

A.2 Worked example: Approximating option value

Oakley Greenwood developed a worked example using data from United Energy's RIT–D report on the Lower Mornington Peninsula.[85] Oakley Greenwood's worked example entailed:[86]

- Relying on data from the RIT–D wherever possible.

- Modelling a business-as-usual scenario (in terms of the NPV of costs), reflecting the RIT-D capex, opex and demand management assumptions.

- Assuming the least-cost means of balancing supply and demand, under a POE 50 scenario.

- Estimating a POE 90 scenario, based on the impact that a large-scale take-up of battery storage could have on the underlying POE 50 demand forecast. This assumes a 10 per cent chance that there will be a 15 per cent penetration of batteries within 10 years, and that each battery would contribute 2.5kW of peak demand reduction (5kW of continuous cycle, over 2 hours).

- Estimating the impact the POE90 demand forecast could have on the timing of the original expenditure program as described in the RIT-D, based broadly on when the new POE 90 demand forecast would reach the original threshold level that triggered the expenditure under the POE 50 scenario.

---

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

85   United Energy, *Lower Mornington Peninsula Supply Area: Project Assessment Report Lower Mornington Peninsula Supply Area Project № UE-DOA-S-17-001*.

86   Also see Oakley Greenwood, *Advice on the DMIS incentive prepared for AER*, 23 June 2017, p. 16.

- Assuming the distributor would have to utilise demand management for three years before it can see whether the high demand scenario under the POE90 forecast scenario comes to fruition.

Table 7: Assumptions for Lower Mornington Peninsula Project

General Assumptions		DM parameters		Capital and Operating Cost Parameters		Demand Parameters	
Annual inflation	2.5%	DM total cost in RIT-D	917,500 ($2016)	Total capital cost in RIT-D	29.5 ($mil 2016)	Current POE50 peak demand	110.00 MVA
Starting Year	2016	DM required in RIT-D to defer capex	12 MVA per annum	Original capex construction year in RIT-D	2022	Estimated number of customers served*	60,000
Discount rate[87]	6.37%	Raw cost per MVA in RIT-D	$76,458	New construction year (assume POE90 deferral) – Capex*	2028	Customers with a battery in 10 years under POE90 scenario*	15%
Assumed impact of each battery[88]	2.5kW	Original - Start year DM in RIT-D	2018	Annual opexcosts	147,500 ($2016)	Impact of battery*	22.5 MVA
		Original - End year DM in RIT-D*	2021	Original year – Opex commences	2023		
		Final year when DM is required to generate option value*	NA	New start year of opex (assume POE90 deferral)*	2029		
		Start year when DM is required to generate option value*	NA				

Source: United Energy, *Project Assessment Report Lower Mornington Peninsula Supply Area Project*.

*   Oakley Greenwood's assumption in *Advice on the DMIS incentive: Prepared for AER*, June 2017, p. 16.

Table 8 summarises the results of Oakley Greenwood's worked example on approximating option value under United Energy's Lower Mornington Peninsula project.[89]

---

[87] Based on Jemena, Diggers Rest RIT–D modelling.

[88] Based on Tesla Powerwall, continuous discharge of 5KW over 2 hours.

[89] United Energy, *Lower Mornington Peninsula Supply Area: Project Assessment Report Lower Mornington Peninsula Supply Area Project № UE-DOA-S-17-001.*

This entailed estimating the uplift percentage applicable demand management as:

$$\frac{NPV(raw\ option\ value \times 10\%)}{NPV(DM\ cost\ for\ 3\ years)}$$

Table 8: Results for Lower Mornington Peninsula Project

Parameter	Results
NPV of original servicing approach	$26,969,373
NPV of alternative approach assuming POE 90 forecast (excluding option cost)	$18,923,062
NPV (option cost)[90]	$0.00
Option value (raw)	$8,046,312
Option value (probability weighted)	$804,631
Uplift percentage on DM expenditure[91]	26.53%

This worked example includes several caveats. For instance, the analysis:

- Did not seek to determine whether demand management had the highest net benefit.

- Relied on several assumptions. This included assuming a 10 per cent probability of a 15 per cent penetration of battery storage occurring within 10 years, which would reduce peak demand by 2.5kW per battery. However, option value will depend on numerous factors in practice.

- Assumed that everything else was equal when assessing the options.

---

[90] There is no incremental option cost in this scenario, as it is assumed that the demand management project that underpinned the preferred option in the RIT-D creates the option value.

[91] Probability weighted option value divided by cost of demand management option in RIT-D.

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 they assess a project, but the numbers used are not based on a real identified need. This worked example 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 to address the identified need.

table 9 and table 10, 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 to address the identified need.

table 9 and table 10 are calculated with reference to a base case of doing nothing to address the identified need.

Table 9: 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 10.

Table 10: 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 contracted, then this project is eligible to receive the uplift of 50 per cent. This uplift 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.[92]

This example illustrates a project that is currently net benefit neutral, but has the capacity to delay capital expenditure. 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 SA Power Network's (SAPN's) RIT–D for the Kangaroo Island submarine cable. This worked example is for illustrative purposes only. As noted later, the preferred option for the identified need in this RIT–D entailed installing a new 33kV submarine cable.[93] 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-

---

[92]   If the distributor had a MAR of $800 million, the maximum incentive they could receive in one regulatory year would be $8 million (being 1.0 per cent of MAR). 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.

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

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 11 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 11: 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 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	$7.8 million: Kingscote, 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	$2.7 Million per annum, escalating at CPI : Capacity 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

| submarine cable across Backstairs Passage in the event of a failure of the existing submarine cable. | provide adequate line thermal capacity; plus $1.76 million: Installing a Voltage Regulator at Penneshaw Substation to provide voltage support. | the evaluation period. |

Given the information available in SAPN's final project assessment report, we would form the view that the opex items in table 11 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 13 applies the information from SAPN's final project assessment report to the project incentive calculation in equation 1 under the draft Scheme. The figures in table 12 are based on SAPN's assumption of 'standard growth'.

Table 12: 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	$\begin{aligned} & Substation\ upgrades \\ & + underground\ cable\ connection \\ & = 6.7 + 1.3 = 8.0 \end{aligned}$	33.558	$33.558 - 8.0 = 25.558$
2: Wind, solar, diesel	$\begin{aligned} & Substation\ upgrades \\ & + overhead\ line\ connection \\ & = 8.3 + 1.7 = 10.0 \end{aligned}$	100.612	$100.612 - 10.0 = 90.612$
3: Diesel, solar + future cable	$\begin{aligned} & Substation\ upgrades \\ & + raising\ line\ design\ temperature \\ & + install\ voltage\ regulator \\ & = 7.8 + 0.4 + 1.76 = 9.96 \end{aligned}$	42.531	$42.531 - 9.96 = 32.571$

Applying the project incentive calculation

Table 13 applies the information from SAPN's final project assessment report to the project incentive calculation in equation 1 under the draft Scheme. The figures in table 13 are based on SAPN's assumption of 'standard growth'.

Table 13: 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	$\min \begin{Bmatrix} 16.285; \\ 7.133 \end{Bmatrix}$ = 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 13 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.[94] As such, none of these projects would have been eligible for incentives under the Scheme. However, if the non-network options in table 13 were the credible options, and before we calculated the total financial incentive capped at 1.0 per cent AR:

- SAPN would select the first option, based on biomass, solar and diesel generation. Out of the three non-network options, this option had the highest expected net benefit relative to the base case ($14.407 million). The net benefit constraint would not bind in this case, and the project incentive would equate to the full 50 per cent of its expected demand management costs (that is, $12.779 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). Since 50 per cent of its expected demand management costs would have exceeded its expected net benefit, the net benefit constraint would bind. The binding constraint would result in an effective cost uplift of $\frac{7.133}{32.571} = 21.9\%$ as opposed to the full 50 per cent.

- 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

---

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

Kangaroo Island, not for reliability corrective action.[95] As such, any proposed solution would need to provide a positive net market benefit to satisfy the requirements of the RIT–D 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 13 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 only committed this eligible project in 2015–16.

Assume SAPN's AR in 2015–16 was $682.03 million, and therefore 1.0 per cent of AR would be 6.82 million.[96] In this case, since project incentive would have been $12.770, 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.

---

[95] SAPN, *Final project assessment report: Kangaroo Island submarine cable*, 23 December 2016, p.18.
[96] This equates to SAPN's annual smoothed revenue requirement (AR) for year 2015–16, ignoring any potential outcomes of ongoing appeal processes.