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Mr Warwick Anderson
General Manager, Network Regulation
Australian Energy Regulator

Submitted by email: DM@aer.gov.au

Dear Mr Anderson,

RE: Submission in response to Draft Demand Management Incentive Scheme and proposed DMIS Early Implementation Rule Change

The Institute for Sustainable Futures (ISF) is pleased to offer this submission on the Draft Demand Management Incentive Scheme (DMIS), Innovation Allowance Mechanism and proposed DMIS Early Implementation Rule Change.

ISF warmly congratulates the AER on designing a Draft Scheme that is moderate, but also innovative, broadly credible and potentially a significant milestone in delivering least cost electricity to Australian consumers.

However, as would be expected in the first draft of any major regulatory reform, there remain a number of significant issues that need to be addressed if the reform is to fulfil its potential.

The following comments are focussed on these issues. The majority of these comments relate specifically to the text of the Draft Demand Management Incentive Scheme. There are also a small number of comments addressing the Draft Demand Management Innovation Allowance Mechanism and the Demand Management Incentive Scheme Early Implementation Rule Change.

I would be very happy to elaborate on the following comments if this would be helpful.

Yours sincerely,

Chris Dunstan
Research Director
Institute for Sustainable Futures

1. General comments

Eligibility limits

The Draft DMIS sets three eligibility limits on DM projects:

1. It must be the most cost effective option (excluding environment costs). That is:
    - The net cost of the final preferred option to customers must be less than the expected cost to customers of doing nothing, and
    - The final preferred option must have lower net costs to customers than other credible options;
2. The incentive is capped at 50% of the cost of the DM project (excluding net market benefits);
3. The total incentive payment is capped at 1% of distributors' Maximum Allowable Revenue.

The AER probably has little room to move on the first criterion over the exclusion of environmental costs, given the current state of the NEO and the NER. However, the latter two criteria err on the side of conservatism and therefore unnecessarily limit the scope for cost effective network DM. On the other hand, these limits also afford major scope for expanding network DM compared to the status quo. It is recommended that AER monitor the performance of the DMIS over the first few years, with a view to relaxing the latter two criteria over time.

Administrative burden and need for an accompanying guideline

It is appropriate that the AER proposes adequate processes and compliance reporting, both to ensure efficient and cost effective outcomes for consumers and to substantiate that this has occurred. However, there is a major risk in the case of the Draft DMIS that the process and compliance burden may become so costly and onerous, that it erodes the net value of savings to customers and obstructs the delivery of cost effective projects. This is particularly so in relation to the calculation of net benefits. In our view it would be a major mistake to bind the processes of the DMIS to the onerous and complex assessment processes of the RIT-D (see item 10 below).

Many of the following specific comments are directed to this issue of complexity and streamlining of administrative burden, but it is also recommended that the AER review the draft scheme with this issue in mind.

It is strongly recommended that the AER accompany the scheme with a guideline to provide greater clarity of how the DNSPs should comply with the Scheme. This guideline would not carry the same regulatory weight of the Scheme itself, but could ensure greater ease and consistency of process, analysis and compliance by distributors and simpler administration by the AER. It would also allow the AER to update minor administrative processes around the DMIS more easily without the complexity of revisiting the whole Scheme.

As a minimum, the proposed DMIS guideline should include guidance on:

- How to calculate net benefits, including worked examples;
- Standardised values for key factors, such as the value of customer reliability, avoided cost of generation and transmission capacity;
- A standard reporting template document, and compliance metrics.

2. Streamline calculation of net economic benefits

Section 1.3 c) states:

> "the scheme should balance the incentives between expenditure on network options and non-network options relating to demand management. In doing so, ***the AER 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"

This gives the AER discretion over whether and how to account for net economic benefits for various stakeholders. Accordingly, in the Draft Scheme, the AER proposes:

s.2.2:

(3) To be an **eligible project**, the **NPV** of the project's net economic benefit to all those who produce, consume and transport electricity in the **relevant market** must be positive when assessed against a base case of:

(a) The network option with the highest net economic benefit to all those who produce, consume and transport electricity in the **relevant market**, where the project is for reliability corrective action.

(b) Doing nothing, where the project is not for reliability corrective action.

However, to assess the "net economic benefit to all those who produce, consume and transport electricity" would be onerous, arbitrary and unnecessary. It would be onerous, as there are many actors who produce, consume and transport electricity, for each of whom it would in principle be necessary to estimate the benefits and costs of the project. It would be arbitrary as, unless the AER provides extensive specific guidance, each DNSP is likely to apply different assumptions and methods so that these assessments would be complex, inconsistent and, in practice, often unverifiable. It would be unnecessary because most of these stakeholders' benefits and costs tend to cancel each other out. For example, a decrease in wholesale prices is generally a *benefit* to electricity suppliers, but a *cost* to consumers. Similarly, a reduction in electricity sales volume means a reduction in *revenue* for electricity generators and retailers, but assuming competitive markets, would also involve an equivalent reduction in their short run and long run *costs*.

It is understood that the purpose of including reference to "produce … and transport" in the net benefits analysis is to ensure that relevant "net market benefits" are taken into account. However, there are much simpler ways to do this than to seek to calculate "net economic benefit to all those who produce, consume and transport electricity in the **relevant market"**

Consequently, it would be much more efficient, more consistent, and probably no less accurate, to limit the net benefit analysis to those network DM benefits and costs that impact directly on customers; that is, the net impact on distribution network service costs, plus transmission and generation capacity costs[1]. Other factors such as: changes in generation fuel costs, changes in retail margins, changes in customer energy charges, changes in unserved energy, changes in wholesale and retail price levels and changes in productivity and comfort for consumers are best excluded from the analysis of net economic benefits.

It would also be economically efficient to include the environmental cost of carbon emissions in the calculation of net economic benefits. However, it is recognised that the AER may consider that the current formulation of the National Electricity Objective and the National Electricity Rules preclude the AER from taking account of this factor. Such an exclusion of environmental costs would be unfortunate, particularly in the current absence of other effective policy to account for the environmental cost of carbon emissions, but would also be consistent with recent regulatory practice in Australia.

Suggested new wording:

s.2.2:

(3) To be an **eligible project**, the **NPV** of the project's net economic benefit to all those who ~~produce~~, consume ~~and transport~~ electricity in the **relevant market** must be positive when assessed against ~~a base case of~~:

(c) ~~The~~Any initial preferred option or other network or non-network credible options; ***and*** ~~with the highest net economic benefit to all those who produce, consume and transport electricity in the **relevant market**, where the project is for reliability corrective action.~~

(d) Doing nothing~~, where the project is not for reliability corrective action~~.

It is recommended that this simpler, more streamlined approach to calculating NPV of project net benefits (i.e. deleting "produce" and "and transport") should be adopted throughout the Scheme, including in the following sections:

Sections 2.2(3) (as above), 2.3(2b), 2.3(3) (incl. Equation 1), 2.3(5), 2.4(5b) and in the Glossary.

[1] It is appropriate to include peak transmission and generation capacity costs because these costs are generally not reflected in prices to customers. If such costs were passed directly through customers, such as via real time dynamic peak pricing for generation, transmission and retail prices, then customers could factor these costs into their energy use decisions and it could be considered legitimate to exclude these from the analysis for distribution network costs too.

Once these references are removed, it is possible to refer to capturing the value of relevant net market benefits associated with "produce and transport" through the current reference in section 2.2 (5) and a reference in the explanation of Equation 1, as follows:

Equation 1: Project incentive calculation

$$PV\ incentive_i \cancel{=} \leq d_v \times E[PV\ DMcost_i]$$ [2]

Subject to the constraint:

$$\cancel{d_v \times} E[PV\ DMcost_i] \leq E[NPV_i]$$ [3]

Where:

Subscript *i* means the parameter concerns ~~**eligible**~~ **committed project** *i*. [4]

PV is the present value at time t . A parameter following PV is in real dollars at time t.

$incentive_i$ is the **project incentive** for each project *i*

$E[.]$ denotes an expected value.

$DMcost_i$ is project *i*'s **demand management** costs

NPV_i is the net present value of the benefit of option *i* to all those who ~~produce~~ consume ~~and transport~~ electricity in the **relevant market** relative to the expected cost of doing nothing. This calculation should exclude the project's DM costs and include the expected avoided costs to consumers of the "Do Nothing" option, plus any expected savings in the net costs of generation and transmission networks.

3. Clarify DM costs recoverable from other sources.

1.3 (d) the level of the incentive:

i. should be reasonable, considering the long term benefit to retail customers;
ii. should not include costs that are otherwise recoverable from any ~~an~~other source, including under a relevant distribution determination; and
iii. may vary by distributor and over time;

For the avoidance of doubt, it would be helpful for the AER to clarify that, while the DM incentive "should not ***include*** costs that are otherwise recoverable from any other source, including under a relevant distribution determination", the DM Incentive is intended as a cost uplift ***in addition to*** DM costs recoverable through a relevant distribution

[2] See item 7 below.
[3] The "d factor" should presumably be removed from this constraint so that the expected cost is simply less than or equal the expected value of the project.
[4] See item 8 below.

determination. To do otherwise would introduce a new bias in favour of proposed Network Capex and against proposed DM Opex.

Therefore, if a distributor chooses to include in its distribution determination proposal an allocation for DM Opex, instead of Network Capex, then it should be permitted to receive a DM incentive for such DM Opex. While this is logical and it appears that this is the intent of the AER, it would be helpful for the AER to make its intent explicit. This could be achieved by altering s. 2.1.1 (b) as set out below.

Suggested changes:

2.1 Application of the scheme

- The **AER** will determine how, if at all, this **scheme** will apply to a **distributor** for a **regulatory control period** through the following process:

…

(b) The **distributor's regulatory proposal** must include a description, including relevant explanatory material, of how it proposes this **scheme** should apply for the relevant **regulatory control period**. The **distributor's regulatory proposal** must also detail how its proposed approach would satisfy the requirements of the **National Electricity Law** and **NER**. The **distributor's regulatory proposal** may include proposed **demand management** expenditure that may be eligible for **incentives** under this **scheme** and proposed network expenditure that may be deferred or avoided by **demand management** projects under this **scheme.**

4. Initial preferred option vs final preferred option.

The rule makes several references to “preferred option”. However, this term is used in two distinct senses. These senses can be characterised as:

“Initial preferred option”- an initial point of comparison in the **minimum project evaluation requirements**

“Final preferred option”- the final option that is selected as the most cost effective.

“Initial preferred option” is the sense applied in sections: 2.2 (2), 2.2.1 (d), 2.3 (5b),

(Note that in the last of these cases, the draft scheme refers to “preferred ***network*** option”. However, as there is no apparent reason why the “initial preferred option” should be presumed to be a network option rather than DM option, this reference to “network” should be removed.)

"Final preferred option" is the sense applied in sections: 2 Figure 1, 2.2 (5b), 2.2.2(1a), 2.2.2(1b), 2.4 (5),

These two separate senses should be made clear and also included separately in the Glossary.

5. Initial preferred option not necessary, but NPV of network need should be

The Draft Scheme requires that the distributor issue a "description of the project it has identified as its **preferred option**" (s. 2.2.1 (4d)). This provision reflects an inefficient and outdated approach of treating demand management as subordinate to a previously identified network solution, rather than as an equally legitimate potential solution to a network constraint.

While it would of course be helpful for the distributor to publish such a description where a preferred option already exists, it would be wasteful, inefficient and potentially counterproductive to require the distributor to develop a preferred option purely for the purpose of issuing a request for demand management solutions. For example, the distributor may wish to use the request for demand management solutions in order to identify its preferred, most cost effective option to address a network constraint.

On the other hand, it would be very helpful to complement the technical information provided in the request for demand management solutions by requiring the inclusion of the expected cost to consumers of not addressing the identified network need, or "Doing Nothing". This should be relatively straightforward to calculate based on forecast energy at risk, probability of energy shortfall and value of customer reliability.

Suggested changes:

5.2.1 Minimum project evaluation requirements

…

(2) Where an **identified need** on its **distribution network** could be fully or partly addressed by a **demand management** solution, a **distributor** must issue a **request for demand management solutions**

…

(3) As part of the **request for demand management solutions**, the **distributor** must provide the following information:

(a) A description of the **identified need** that the **distributor** is seeking to address.

(b) Technical information about the **identified need**, including the load at risk, energy at risk, duration and load curves, ~~and~~ the annual probability and frequency of relevant events and expected value of energy at risk (based on energy at risk, probability of energy at risk and value of customer reliability).

(c) The location of the **identified need** and a description of the affected classes of customers and network area.

(d) ~~A description of the project it has~~ If the distributor has identified ~~as its~~ an **initial preferred option** to meet the **identified need** on the **distribution network,** a description of this initial preferred option.

6. Characterisation of Demand Management is too narrow

The Draft Scheme includes several references to the demand management being subject to the Distributor's "request or control". (see sections 2.2.1 (5c), 2.2.2 (2) and 2.2.2 (3). While this is an appropriate term for demand response, it is not appropriate for other, more permanent or indirect, forms of demand management such as energy efficiency, fuel switching and some embedded generation and price reform. It is therefore proposed that this phrase be extended to "influence, request or control".

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

Section 2.3 (2) implies that the actual project incentive claimed by the distributor may be at a level lower than the incentive "cap". While it is expected that the distributor will normally seek to claim the maximum available incentive, the AER may wish to make explicit this implication about downward flexibility.

8. "Committed" not "eligible" projects

Section 2 (1), Figure 1 and Equation 1 refer to "eligible projects". However, given the definitions of "eligible project" and "committed project", these should presumably be references to "committed projects"

9. Defining committed projects

The Draft Scheme does not prescribe a **maximum lead time** for the commencement of a committed project. This means that the commencement of the DM project may occur after the cost of the DM incentive has been recovered from customers. This would create unnecessary risks for customers and the distributor. Therefore, it is recommended that a maximum lead time for the commencement of committed project be stipulated.

The Draft Scheme also does not prescribe a **maximum project expenditure period**. Consistent with the AER's general practice for operating expenditure, it is proposed that a maximum period for expenditure on DM projects be set at the same length as to a distributor's regulatory period, that is, five years. Distributors should be permitted to recommit to a DM project and seek a further DM incentive at the end of this period, subject to the rules of the DMIS prevailing at that time.

These two provisions could be accommodated as follows:

2.3 Determining project incentives

> **…**
>
> (6) Project incentives are only payable for committed projects which have already undertaken expenditure and are delivering DM outcomes, or are committed to undertake expenditure and deliver DM outcomes, in years prior to the year in which the incentives are paid. That is, incentive payments made in year t will only be payable for projects committed in year t-2, ***and*** for which expenditure and outcomes have commenced or are committed to commence in years t-2 or t-1.
>
> (7) Project incentives will only be payable for DM project costs up a maximum period of five years.

10.Do not bind the DMIS to the RIT-D

Section 2.3(5) requires distributors to *"calculate the expected present value of project* i's *net benefit to all those who produce, consume and transport electricity in the* ***relevant market*** *referred to in clause 2.3(2)(b) and equation 1 in accordance with the requirements for carrying out cost–benefit analysis that are set out in the* ***RIT–D****."*

In ISF's view, this provision which links the Draft Scheme to the processes of the RIT-D, would be a serious error and a grave threat to the effectiveness and efficiency of the DMIS. The RIT-D is very complex, onerous and therefore costly. In many cases, the cost of undertaking RIT-D processes is likely to exceed the costs of undertaking the DM project and the benefits to customers of the project. It is very plausible that in many cases, the distributor will prefer to forego the potential customer and distributor benefits of DM, including the DM incentive, in order to avoid the costs of undertaking a RIT-D process. Practice to date has shown that different distributors adopt different approaches to calculating benefits under the RIT-D. Consequently, relying on the RIT-D is likely to be inconsistent and probably administratively burdensome for the AER, as well as the distributors.

Section 6.6.3 of the National Electricity Rules which governs the DMIS makes no reference to the RIT-D and there is no requirement for the AER to draw such a link. Moreover, the RIT-D only applies to proposed network investments with an expected value of greater than $5 million. The vast majority of DM projects are likely to be much less costly than this.

Finally, linking the **minimum project evaluation requirements to the "***cost–benefit analysis that are set out in the* ***RIT–D"*** manifestly undermines the whole point of adopting minimum project evaluation requirements, which are intended to be simpler than the RIT-D.

The AER can and should apply much simpler net benefit test than that prescribed in the RIT-D. A simpler process could be as set out below:

1. Distributor assesses the expected customer cost of the “Do nothing case”. This can be summarised by:
    a. Assess current and expected network capacity and compare this to forecast load.
    b. Apply the expected probability of energy shortfall to estimate the expected customer energy at risk.
    c. Multiply the expected customer energy at risk by the value of customer reliability to derive an expected (NPV) value of customer energy at risk. This is a simple proxy value for the expected customer cost of the “Do nothing case”.
2. *(Optional step)* If it wishes to, the distributor develops and costs an initial preferred option. This could be a network option, a DM option or a combination of both. If the (NPV) cost of this initial preferred option is less than the (NPV) expected cost of the “Do nothing” case, then this is a potentially cost effective option.
3. Test the Market. This could take the form of a RIT-D process for larger (>$5million), or a simpler **request for demand management solutions.** If the (NPV) cost of credible responses to the **request for demand management solutions** are less than the (NPV) expected cost of the “Do nothing” case, then these are potentially cost effective options.
4. Subtract from the (NPV) cost of any credible DM option, any relevant distributor option value and any expected associated customer savings in the (NPV) net costs of generation and transmission networks (including option value if relevant).
5. Compare the (NPV) cost of the credible options from steps 2 and 4 and choose the least net cost option as the final preferred option.
6. Subtract the (NPV) net cost of the final preferred option from the (NPV) customer cost of the “Do Nothing” option. **This is the final (NPV) net benefit value of the final preferred option**. If this value is greater than zero, then the final preferred option is the most cost effective option.

It is strongly recommended that the AER does not require a link between the DMIS and the RIT-D processes. Instead, it is proposed that much simpler cost benefit processes be adopted, such as that described above. Furthermore, it is recommended that the AER provide more detail, templates and worked examples of how to undertake cost benefit analysis via an AER guideline to accompany the Final DMIS[5]. The suggested changes to Section 2.3 (5) are set our below.

Suggested changes:

Section. 2.3(5)

A **distributor** must calculate the expected present value of project *i*'s net benefit to all those who ~~produce~~, consume ~~and transport~~ electricity in the **relevant market** referred to in clause 2.3(2)(b) and equation 1. ~~in accordance with the requirements for carrying out cost benefit analysis that are set out in the **RIT–D**. This includes the requirement that the **distributor** estimate project *i*'s net benefit relative to 'the base case', being:~~

(a) ~~where **distributor** does not implement a **credible option** to address the **identified need**; or~~

(b) ~~if the **identified need** is for reliability corrective action, where the **distributor** implements its preferred **network option**.~~ This calculation of net benefit should exclude the project's DM costs and include the expected avoided costs to consumers of the "Do Nothing" option, plus any expected savings in the net costs of generation and transmission networks, plus any relevant option value.

11. Improved compliance reporting

Section 2.4 requires the distributor to include in its compliance reporting for committed projects the following metrics:

- Estimates of the *actual* demand reduction delivered in that year associated with previously committed projects (measured in kVA per year) - s.2.4((4b)
- Estimates of the *actual* benefits realised in that year associated with previously committed projects (measured in kVA per year) - s.2.4((4b)
- Estimates of the total financial incentive that the distributor is claiming for newly committed projects.

This is insufficient information to demonstrate clearly to stakeholders the value for money of the DM projects undertaken under the DMIS. It is recommended that this reporting be expanded to include the following, to be reported on an annual basis.

For all committed DM projects subject to the DMIS:

(1) Year of commitment
(2) Value of DM incentive provided to the distributor under the DMIS
(3) Annual and cumulative cost of DM project to the distributor
(4) Annual and cumulative value of savings to the distributor
(5) Annual and cumulative reduction in demand (kVA per year)

[5] It is noted that the worked examples in the Explanatory Statement for the Draft DMIS do not work through the detailed benefit cost analysis from the RIT-D examples they cite.

(6) Annual and cumulative reduction in energy consumption (MWh)
(7) Annual and cumulative reduction in associated carbon emissions (t CO_2e)
(8) Annual and cumulative other benefits to the distributor
(9) Annual and cumulative value of bill savings to customers
(10) Annual and cumulative value of incentives provided to customers
(11) Annual and cumulative reduction in value of customer energy at risk
(12) Annual and cumulative value of total benefits to customers

Similar data should be reported for eligible projects where appropriate.

It is recommended that the AER provide more detail, templates and examples of how to report compliance by means of an AER guideline to accompany the Final DMIS. Ideally, this compliance reporting would be harmonised with a standardised reporting framework for reporting of all demand management including that outside the purview of the DMIS.

12. Recovery of DM incentives for committed projects that do not proceed as planned

The Draft Scheme has very limited provisions to ensure that committed projects are undertaken and deliver outcomes consistent with their committed objectives. Section 2.4 (6) and Section 2.4 (7) require the distributor to disclose if a committed project does not proceed as previously planned. However, the Draft Scheme does not include provision to recover any DM incentives for committed projects that do not proceed. Nor does the Draft Scheme provide for recovering DM incentives for projects which fall short of planned expenditure or customer benefits. This creates potential for moral hazard, chronic underperformance of projects and inequitable treatment between distributors.

It is recommended that the AER take steps to remedy this deficiency.

13. Timing for determining total financial incentive

Figure 2 outlines the timeline for determining the total financial incentive. It states that at “t-3 months”, the AER determines the total financial incentive for the distributor and that at the same time, that is, “t-3 months”, the distributor must submit its pricing proposal for year t to AER, including the approved DM incentive. This timeline seems impractical and it is recommended that a gap of at least one month be established between the AER determining the total financial incentive and the distributor submitting its annual pricing proposal.

14. Comment on Draft Demand Management Innovation Allowance Mechanism

Section 2.2.1 of the Draft Demand Management Innovation Allowance Mechanism states:

2.2.1 Project criteria

…

(2) A project or program is not an **eligible project** *if any part* of the costs of the project or program are:

i) recoverable under any other jurisdictional incentive scheme;

ii) recoverable under any state or Australian Government scheme; or

iii) otherwise included in forecast capital expenditure or operating expenditure approved in the **distributor's** distribution determination.

This appears to be excessively restrictive. Many innovative research projects are jointly funded. This not only spreads the risk and cost of the research project, but also involves a wider range of stakeholders, expertise and insights in the research. While the AER should not allow the distributors to recover from customers, any part of project costs that are funded by other programs or schemes, it is not clear why the AER would wish to preclude collaborative funding of worthwhile research.

15. Comment on Consultation Paper: Demand management incentive scheme early implementation rule change

ISF strongly supports the AER's proposed Rule Change to allow new DMIS to be brought forward to start during the current regulatory period.

In the best case, the effect of this proposed rule will be to give consumers early access to net electricity bill savings due to cost effective network demand management. The worst case would be a neutral outcome where distributors fail to take advantage of the potential earlier benefits to them and to their consumers of cost effective network demand management.

The proposed rule can be expected to contribute to meeting the national electricity objective by supporting the reliability of electricity supply and by putting downward pressure on spot and retail electricity prices as a result of the implementation of cost effective network demand management.

In summary, there is little if anything to lose from adopting the proposed rule change and potentially much for consumers to gain.