19 March 2015

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Pierce,

RE: AEMC Consultation Paper – *National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015* (Reference ERC0177)

The NSW Distribution Network Service Providers, Ausgrid, Endeavour Energy and Essential Energy (the NSW DNSPs) welcome the opportunity to provide feedback on the AEMC's Consultation Paper – *National Electricity Amendment (Demand Management Incentive Scheme) Rule 2015.*

The NSW DNSPs support the nature of the changes proposed by Total Environment Centre (TEC) and the Council of Australian Governments (COAG) Energy Council (the proponents). We share the proponents' view that the current demand management and embedded generation connection incentive scheme (DMEGCIS or 'incentive scheme') has not been effective in encouraging efficient levels of demand management in the National Electricity Market (NEM) and that changes to the National Electricity Rules (Rules) are required to address this issue.

From a distribution network service provider's (DNSP) perspective, the current incentive scheme has provided weak incentives for DNSPs to undertake demand management. This has been largely due to:

- the inability of the scheme to capture market benefits from demand management initiatives;
- the incentive scheme operating as a pass through of costs rather than a "true" incentive scheme which allows for rewards to be earned for delivering defined goals;
- the short term focus of the incentive scheme, which only allows for consideration of benefits that accrue within the regulatory control period;
- the complexity of the current incentive scheme design; and
- the Australian Energy Regulator's (AER's) narrow application of the scheme.

We consider that it is important that these issues are addressed in order to promote efficient investment in the NEM. Encouraging cost effective demand management is consistent with the National Electricity Objective (NEO), as it promotes the efficient operation, use of and investment in, electricity services.

The NSW DNSPs consider that the changes proposed by the proponents are likely to contribute to the achievement of the NEO, as they are aimed at improving the effectiveness of the incentive scheme. In our view, the changes are appropriately targeted at addressing the flaws identified in the current operation of the incentive scheme, and if adopted, would likely promote an economically efficient level of demand management in the NEM.

In addition to the changes proposed by the proponents, the NSW DNSPs have also identified supplementary amendments which should be incorporated into the design and application of the demand management innovation allowance (DMIA) to address factors contributing to the underutilisation of the innovation allowance by DNSPs.

The Power of Choice Review noted that a key factor for why the DMIA had to date been underutilised was due to the perception that the allowance was too modest for demand management projects to be implemented under the scheme. Whilst the AER has opposed increasing the size of the DMIA on the basis that it is customers who ultimately fund the scheme, the NSW DNSPs are concerned that there may be a mismatch between the value placed on demand management by customers and the level allowed by the AER acting on behalf of customers.

The NSW DNSPs consider that the Rules should specify that, in determining the appropriate level of DMIA, the AER is required to demonstrate how it has identified and taken into account customer preferences and their willingness to pay for demand management innovation. In addition, there should also be a requirement for the AER to outline in a supporting guideline its methodology for calculating the DMIA. The transparency gained from these minor amendments will provide more certainty and confidence to DNSPs in how the allowance is determined, thus resulting in the size of the allowance being set at a level which is meaningful and better aligns with customers' preferences. These amendments are consistent with the achievement of the NEO, as they enable DNSPs to explore more ways to innovatively meet changing demand and optimise their existing assets.

Although not specifically identified by the rule change requests but necessary for its successful application, the NSW DNSPs consider that there is value in examining other aspects of the regulatory framework, such as how the AER assesses and approves demand management funding as part of the regulatory determination (reset) process. We are concerned there is a disconnect between the policy intent of amending the demand management incentive scheme (DMIS) so that it is more effective and how funding for demand management projects are assessed and approved by the AER, as part of the regulatory reset process. Further assessment of this issue is required, as the intent of the rule change requests is likely to be frustrated without consideration of the ability of DNSPs to gain approval for funding for demand management projects outside those funded by capital offsets or through the regulatory investment test for distribution (RIT-D).

To reflect the different focuses of our response, the NSW DNSPs have structured our submission into two sections. Section 1 is focused on providing responses to the AEMC's Consultation Paper questions, whereas Section 2 is aimed at highlighting issues raised by the rule change requests which are not addressed by the AEMC's consultation questions.

The NSW DNSPs have worked collaboratively with the Energy Networks Association (ENA) in preparing their response to the AEMC's Consultation Paper. Consequently, we support the views outlined by the ENA's submission and consider that they appropriately reflect industry's key positions on the rule change.

If you have any queries or wish to discuss further please contact Mike Martinson, Group Manager Regulation at Networks NSW on (02) 9249 3120 or via email at michael.martinson@endeavourenergy.com.au.

Yours sincerely,

For Vince Graham
Chief Executive Officer
Ausgrid, Endeavour Energy and Essential Energy

Section 1: NSW DNSPs response to the Consultation Paper questions

Issue 1 Issues this rule change is seeking to address

1. ***Having regard to current and potential future market conditions, and in light of recent changes to the regulatory framework for distribution businesses, is there a gap in the current framework which may be discouraging distribution businesses from pursuing demand management projects as an efficient alternative to network investment?***
2. ***If a gap does exist, where does it lie? Is it a product of the provisions in the NER or a result of the current design of the DMEGCIS applied by the AER?***

NSW DNSPs' response

Issues identified with the current framework

The NSW DNSPs consider that the National Electricity Rules (Rules) framework is sufficiently flexible to accommodate more efficient levels of electricity demand management. However, from a distribution network service provider (DNSP) perspective, this has not occurred to date. This is due to issues arising from the current demand management embedded generation connection and incentive scheme (DMEGCIS) provisions and uncertainty regarding the Australian Energy Regulator's (AER's) assessment and treatment of demand management expenditure during the regulatory determination (reset) process.

The AEMC determined during its Power of Choice review -"giving consumers options in the way they use electricity" (Power of Choice Review), that whilst regulatory arrangements were sufficiently broad enough to accommodate demand management, they tended to create a preference towards investment in capital expenditure (capex) for the following reasons:[1]

- the inability of the scheme to capture market benefits from demand management initiatives;
- the incentive scheme operating as a pass through of costs rather than a "true" incentive scheme which allows for rewards to be earned for delivering defined goals;
- the short term focus of the incentive scheme, which only allows for consideration of within regulatory control period benefits;
- the complexity of the AER's current incentive scheme design;
- the AER's narrow application of the scheme; and
- uncertainty regarding the AER's assessment and treatment of demand management related operating expenditure (opex) during regulatory resets.

Identifying where gaps lie

The NSW DNSPs note that the majority of issues outlined above appear to largely stem from the design and application under the current incentive scheme. Whilst the Rules currently afford the AER with broad discretion with regards to the design and application of the scheme it has refrained from addressing these issues, and has instead elected to apply the scheme in a very limited manner.[2]

Consequently, it was determined during the Power of Choice Review that more guidance in the Rules was required to clarify the incentive schemes application, remove ambiguities and to provide greater regulatory certainty for the AER and DNSPs.

A more concerning issue uncovered by the Power of Choice Review was the lack of clarity under the existing framework for DNSPs to obtain funding for demand management projects during their regulatory determinations. The current framework is ambiguous as to how the AER assesses the efficiency of such projects and their associated expenditure trade-offs. In particular, it is unclear whether in assessing the efficiency of the projects the AER is able to take into account the market benefits that such projects can generate or the benefits that may accrue over multiple regulatory periods.

[1] AEMC, *Power of choice review – giving consumers options in the way that they use electricity,* Final Report, 30 November 2012, Chapter 7.
[2] The NSW DNSPs note that the AEMC also shared this view. Refer to AEMC, *Power of choice review – giving consumers options in the way that they use electricity,* Final Report, 30 November 2012, Chapter 7, p 206.

The lack of certainty under the current framework regarding the treatment of demand management expenditure constrains demand management below an economically efficient level as it limits DNSPs to only undertaking demand management projects which can be funded by capex offsets or allowances under innovation component of the incentive scheme. As the AER chose to allow the D-factor component for NSW DNSPs in DMEGCIS to lapse in 2014 there is no incentive component in the "incentive scheme". Nor will there be an incentive component until the rule change is made, guidelines are produced, a scheme designed and the scheme included as part of a DNSP's final regulatory determination.

Addressing gaps in the current framework

In its Power of Choice Review, the AEMC recommended that principles, criteria and an objective be included in the Rules to address ambiguities and provide further guidance to the AER on interpreting provisions and the intended application of the scheme. The AEMC envisaged that by making these recommendations it would provide more opportunity and certainty for networks to pursue demand management projects which deliver savings to consumers.[3]

The rule changes proposed by Total Environment Centre (TEC) and the Council of Australian Governments (COAG) Energy Council (the proponents) largely seek to reflect the recommendations made by the AEMC in its Power of Choice Review.

The NSW DNSPs note that the AEMC's recommendation to include criteria, principles and an objective in the Rules was supported by all stakeholders, including DNSPs and the AER.[4] Consequently, we consider the nature (as opposed to the substance) of the proposed amendments are non-controversial.

Whilst the NSW DNSPs generally support the proposed amendments, we have identified some concerns regarding the substance of the proposed changes. These concerns are elaborated on further in section 2 of our submission.

The proposed amendments appear to be appropriate and well-targeted at addressing issues with the incentive scheme. However, they do not appear to reflect other recommendations made by the AEMC aimed at clarifying the treatment and assessment of demand management expenditure during the reset process. We note that it was anticipated by the AEMC in its Power of Choice Review that changes to address this issue would also be made as part of the rule change request to amend the provisions governing the design and implementation of the incentive scheme.[5]

The NSW DNSPs find this oversight concerning, as without addressing the existing uncertainty that surrounds the AER's approach for assessing and approving demand management allowances proposed by DNSPs (including the AER's approach to taking into account the operating expenditure and capital expenditure trade-offs) the uptake of demand management projects is likely to be limited to small pilots and trials that can be funded through the demand management innovation allowance (DMIA) and deferring specific augmentation projects that can be justified under the regulatory investment test for distribution (RIT-D).

It has been our recent experience that obtaining an opex allowance to fund demand management projects through the regulatory determination process to be difficult.[6] It is particularly problematic to obtain funding for broad based demand management projects[7] aimed at building the DNSP's capabilities to manage demand and improve their network load factor.

These projects are typically characterised by high initial upfront cost, the benefits of which accrue gradually over time and span over multiple regulatory periods. Under the current regulatory framework

[3] Ibid.

[4] Ibid.

[5] Ibid, p 226.

[6] Refer to Attachment 6.12 – Demand Management operating expenditure plan, of Ausgrid's substantive regulatory proposal, May 2014. See also AER, Draft decision*, Ausgrid distribution determination 2014-19 – Attachment 7: Operating expenditure*, November 2014, pp 7-168 to 7-169.

[7] Broad based demand management are aimed at delivering benefits to consumers in the long run by improving the utilisation of existing network assets. This reduces overall network costs, the benefit of which flow back to consumers in the form of lower energy bills.

it is difficult to obtain funding for such projects as it is uncertain whether the AER can take into account broader market benefits and benefits which may accrue over multiple regulatory periods.

It appears from the AER's recent approach to assessing the NSW DNSPs' proposed demand management allowances, that there is a reluctance to approve an opex allowance for demand management projects, despite these projects being based on successful pilots and learnings from similar projects being carried out in Queensland.[8]

In rejecting the proposed expenditure the AER did not consider the potential for benefits other than the deferral of capital expenditure (i.e. consideration was not given to broader market benefits), and appropriate weight was not given to the long term benefits likely to accrue from the projects. Rather, it seems that the AER largely based its view not to provide an allowance for demand management projects on the basis that they would deliver only marginal benefits in light of reforms to enable cost reflective pricing and the operation of the RIT-D.[9]

Further details on this issue can be found in section 2 of our submission.

Impact of changing market conditions and other reforms

Market conditions

Demand growth across the NEM has slowed in recent years, departing from the previous trend of steady year on year growth. This has led to lower forecasted growth in augmentation expenditure and has also created more uncertainty about the optimal capital investment strategy. In this more uncertain environment, there is a stronger basis for DNSPs to adopt demand management options as the demand reductions required to achieve capital deferrals are lower. This makes it easier and more cost effective to adopt non-network alternatives, provided that appropriate rules and incentives are in place to not discourage this behaviour.

Other reforms

There have been a number of reforms aimed at promoting more efficient levels of demand side participation (DSP) in the National Electricity Market (NEM) and reforms to address the bias towards capex investment. However, we do not consider that these changes address the specific issues identified with the incentive scheme or the expenditure framework which were determined in the Power of Choice Review as discouraging the uptake of economically efficient levels of demand management.

The Power of Choice Review examined a number of different areas across the electricity supply chain to determine whether any market/and or regulatory arrangements acted as a barrier to the efficient uptake of DSP. Having identified a number of issues which discouraged DSP, the AEMC recommended a suite of changes to key areas to address this.

Reforms to pricing, metering and the DMEGCIS are just some of the rule changes which have flowed through from recommendations made in the AEMC's Power of Choice Review. While they are related in the sense that they are aimed at facilitating greater levels of DSP, they are targeted at addressing very different issues with market and regulatory arrangements, and as such should be viewed as complimentary measures. Importantly, reforms to pricing and metering arrangements should not be seen as negating or diminishing the benefits to consumers from demand management activities carried out by DNSPs.

The NSW DNSPs find it concerning that the AER appears to have formed the view that reforms to enable cost reflective pricing obviates the need for DNSPs to undertake demand management projects. In deciding not to approve an opex allowance for demand management projects the AER formed the view that benefits (capital deferral) from the projects were likely to be marginal and unlikely to outweigh their costs due to the implementation of cost reflective pricing.[10] Additionally, in rejecting demand management opex, the requisite deferred capex was not reinstated. This undermines the incentive provided by the RIT-D to defer network options in favour of non-network solutions as funding is provided for neither.

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[8] Refer to Attachment 6.12 – Demand Management operating expenditure plan, of Ausgrid's substantive regulatory proposal, May 2014.

[9] AER, Draft decision, *Ausgrid distribution determination 2014-19 – Attachment 7: Operating expenditure*, November 2014, pp 7-168 to 7-169.

[10] Ibid.

Further, in reaching this decision the AER did not place appropriate weight on the cost benefit analysis provided in support of the projects or the fact that the projects were based on successful trials implemented under the DMIA and similar projects implemented in other jurisdictions. Rather, the AER discounted this evidence based on its view of the significant impact cost reflective network tariffs were likely to have on helping defer network expenditure.

The NSW DNSPs strongly disagree with this view. We have provided further reasoning for why cost reflective pricing does not negate or diminish the need for demand management carried out by DNSPs in Attachment 1.

Conclusion

The NSW DNSPs support the nature of the proposed rule changes, noting that they largely reflect the recommendations made in the Power of Choice Review. However, it appears that the rule changes do not incorporate corresponding changes to the expenditure framework which were also contemplated by the Power of Choice Review.

Unless corresponding changes are made to the application of the expenditure framework the proposed changes to the incentive scheme are unlikely to have a material impact in changing the current status quo. The difficulty faced by DNSPs in obtaining an allowance to fund demand management projects during the regulatory reset process acts as a significant barrier to DNSPs in trying to pursue non-network alternatives in order to improve the utilisation of their existing assets.

The NSW DNSPs urge the AEMC to consider this issue further and have outlined our concerns on this issue in more detail in Section 2.

Issue 2 Proposed DMEGCIS

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

- ***a) Having regard to the level of flexibility and discretion afforded to the AER in designing and applying other incentive schemes under Chapter 6 of the NER, is the level of flexibility and discretion currently afforded to the AER in relation to the DMEGCIS appropriate?***
- ***b) If there is benefit in providing more prescription in the NER, is the level proposed by the COAG Energy Council and TEC in their rule change requests appropriate?***

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

NSW DNSPs' response

Flexibility vs prescription

As noted by the ENA, the balance of flexibility and prescription in the Rules governing the design of the incentive scheme does not appear to be optimum. On the one hand the AER has broad discretion regarding the design of the incentive scheme; however on the other, it is unclear whether the Rules allow the AER sufficient confidence to exercise their discretion to recognise net market benefits attributed to demand management projects

In this circumstance, we consider that greater prescription in the Rules is warranted in order to address the ambiguities and gaps identified by the Power of Choice Review.

Prescribing objectives, principles and criteria in the Rules is appropriate and consistent with other elements of the Rules. Adopting this approach will not inappropriately detract from the discretion afforded to the AER under the Rules. Rather, it is envisaged that these changes will provide the AER with greater clarity and certainty in undertaking its role.

TEC and COAG Energy Council proposed changes

In our view, the proposed changes seek to strike an appropriate balance between providing the AER with sufficient guidance on how the scheme should be applied and allowing the scheme to adapt and evolve over time.

However, whilst we support the need for objectives, principles and criteria to be included in the Rules we have some concerns regarding the detail of some of the proposed amendments. In particular, we are concerned that certain elements of the proposed amendments should be included in the incentive scheme or guideline developed by the AER as opposed to the Rule provisions. Prescribing these elements in the Rules will add unnecessary prescription and complication to the incentive scheme.

Our concerns regarding the level of prescription created by certain amendments proposed by the proponent are outlined in more detail in section 2.

Embedded generation connections

As noted by the ENA, the connecting embedded generation rule changes have enhanced and simplified access terms for new embedded generation facilities. However financial incentives under the incentive scheme still have an important role to play in supporting DNSPs in innovatively using embedded generators for demand management where it is cost effective to do so.

Both the DMIA and the incentive scheme should encompass all forms of demand management, including connecting and exporting of distributed generation units. Demand management can take a number of different forms, consequently it is important that the overarching incentive scheme provisions reflect this and remain technologically neutral. The NSW DNSPs consider that it would be inappropriate to predicate the forms of demand management permitted under the scheme, as this may act to “pick winners” by precluding different forms of demand management and stifle innovation.

The NSW DNSPs consider that there is no need to distinguish embedded generation projects from other demand projects conducted under the DMIA and/or DMIS. The NSW DNSPs have been conducting demand management projects under the DMIA with embedded generation and energy storage as a component for some time. Example projects include:

- Reliability of customers embedded generators for demand management;
- CBD embedded generator pilot, exploring protection and connection design barriers for embedded generation connections in the Sydney CBD;
- Newington grid battery trial;
- Energy storage and statcoms for voltage storage; and
- Trials to mitigate the negative impacts of intermittent generation.

Therefore, while it is recognised that embedded generations can provide an effective form of demand management they should not be treated more favourably than any other form of demand management under the incentive scheme. To do so, could give rise to the risk of cross subsidisation and distort investment decisions.

Issue 3 **Demand management innovation allowance**

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

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

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

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

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

NSW DNSPs' response

Benefits of codifying the DMIA

Overall the NSW DNSPs consider that the DMIA has had a positive impact on DNSPs undertaking greater levels of demand management and therefore support its retention. In NSW, the DMIA has been successfully used to fund a number of small trials and program pilots.

The knowledge gained from implementing demand management projects under the DMIA has placed the NSW DNSPs in a better position to assess the magnitude of the likely impact from demand management projects, thus enabling the NSW DNSPs to better identify opportunities where demand management may be the most cost effective solution for addressing specific or emerging network constraints.[11]

The NSW DNSPs consider that there is benefit in separating and codifying the DMIA in the Rules. Whilst related, the DMIA and demand management incentive scheme (DMIS) have differing purposes and objectives. Having the two schemes combined has caused some confusion and has blurred the delineation between the scope of projects permissible under the different parts of the incentive scheme (i.e. which projects are subject to payments under the incentive scheme and which fall more appropriately within the scope of the DMIA).

Consequently, separating the two schemes would help to clearly delineate the scope and differing focuses of the schemes and also clarify funding arrangements.

Determining the appropriate size of the DMIA

The NSW DNSPs consider that the proposed changes to separate and codify the DMIA are likely to encourage DNSPs to trial more demand management projects. Whilst some DNSPs have actively sought to utilise their DMIA allowances this is not always the case. In its Power of Choice Review the AEMC noted that this may be due to the perception that the current innovation allowance is too modest. However, this may also be in part due to the immaturity of the DNSPs demand management capabilities.

The NSW DNSPs consider that the relative size of the DMIA and how the allowance is calculated are factors which have likely contributed to its lower uptake. In the Consultation Paper the AEMC notes that the AER's practice in setting the DMIA is to cap the total amount recoverable within a regulatory period based on its understanding of typical demand management and/or embedded generation connections costs which are then scaled to the relative size of each businesses average allowance in the previous regulatory control period.[12]

Whilst the NSW DNSPs consider that this approach is reasonable for setting the DMIA we do not consider that this reflects how the AER has in practice set the allowance. Rather, it has been our experience that the AER has determined the allowance consistent with the amount provided in the previous period. The robustness of the calculation underpinning the original allowance remains questionable.

The NSW DNSPs do not consider that the proposed amendments address concerns regarding the size of the innovation allowance under the DMIA. We consider that there would be significant benefit if there was greater transparency and predictability surrounding how the DMIA was calculated. This could be achieved by including a requirement in the Rules for the AER to outline its methodology for calculating the DMIA. This would not add unnecessary prescription, or detract from the AER's discretion to determine the size of the innovation allowance. Rather, the transparency gained from this minor amendment will likely provide DNSPs with more certainty and confidence in how the

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[11] The results from demand management trials and pilots provide DNSPs with the necessary underlying data and analytics to determine whether projects of a similar nature would be suitable for wide scale adoption. The use of trials enables DNSPs to become familiar with the use of non-network alternative and have confidence in the benefits that it delivers. Without such information, DNSPs would not be able to substantiate a positive business case for undertaking certain demand management projects, particularly where such projects involve the use of new or unfamiliar technology.

[12] AEMC 2015, *Demand Management Incentive Scheme,* Consultation Paper, 19 February 2015, Sydney, p 23.

allowance is determined and may result in the size of the allowance being set at a more meaningful level.

Increasing the DMIA so that it is more meaningful to a DNSP's circumstance is likely to lead to more of the allowance being utilised. As identified in the Power of Choice Review, a key factor for why the DMIA has been underutilised to date is due to the perception that the allowance is too modest for demand management projects to be implemented under the scheme.

If the size of the DMIA was more meaningful it would likely promote more efficient levels of demand management in the NEM, as DNSPs would be encouraged and supported under the framework to trial innovative non-network alternatives. If proven successful, these projects could be incorporated into the DNSPs business as usual activities. The NSW DNSPs consider that this outcome is consistent with both the NEO and the intended application of the DMIA as set out in COAG Energy Council's rule change request.

The NSW DNSPs note that the AER has to date opposed increasing the size of the DMIA on the basis that it is customers who ultimately fund the scheme. Whilst this is true, customers only fund actual DMIA costs incurred by the businesses, as approved by the AER, which may or may not equate to the total allowance. The NSW DNSPs are concerned that there may be a mismatch between the value placed on demand management by customers and the level allowed by the AER acting on behalf of customers. The Rules could specify that, in determining the appropriate level of DMIA, the AER is required to demonstrate how it has identified and taken into account customer preferences.

The modest size of the DMIA is made even more apparent when compared to the allowances for innovation under the United Kingdom (UK) framework. In the UK, the Network Innovation Allowance (NIA) provides a mechanism for DNSPs to spend 0.5% of their network revenue by default on innovation projects. [13] This contrasts starkly with the DMIA allowed in the NSW DNSPs determination which represents 0.04% of allowed network revenue.[14] Further, under the UK framework two further funding mechanisms are available to DNSPs for innovation related activities[15]:

1) an annual Network Innovation Competition (NIC) for large scale projects conducted by transmission and distribution companies, set at £90m per year; and
2) an Innovation Rollout Mechanism (IRM) to enable companies to apply for additional funding to roll-out proven innovation which meets the defined criteria.

Consequently, it appears that Australia's regulatory framework is quite conservative in the allowance and support provided to DNSPs to undertake innovative demand management projects. This has likely contributed to the relatively lower levels of expenditure on demand management.

The NSW DNSPs agree that it is appropriate for the AER to determine the size of the allowance and that this allowance may vary between DNSPs. However, as outlined above, a more meaningful level of funding could be achieved if the AER was required to consult on its methodology for determining the size of the allowance. This would provide greater transparency in how the allowance is set.

DMIA reporting

While there may be some overlap with the distribution annual planning report (DAPR) and demand side engagement strategy (DSES), it is recognised that these documents are generated for different purposes and are aimed at catering to different audiences. Consequently, the NSW DNSPs share the ENA's view that it is appropriate to establish tailored reporting requirements for the DMIA. The innovation allowance is funded by network consumers with the goal of producing a 'public good' comprising of access to information and data on innovative projects.

The NSW DNSPs consider that current annual reporting requirements under the DMIA are sufficient. However, if further changes are deemed to be necessary we consider that they should be geared towards industry DMIA knowledge sharing in order to provide the maximum benefit and minimise

[13] Ofgem, March 2013, *Price Controls Explained*, Factsheet 117, https://www.ofgem.gov.uk/ofgem-publications/64003/pricecontrolexplainedmarch13web.pdf

[14] The figure 0.04% is based on Ausgrid's $5million DMIA being expressed as a percentage of Ausgrid's revised smooth network revenue requirement for the 2014-19 period of $11.9 billion (nominal), as per Ausgrid's *Revised Regulatory Proposal and Preliminary Submission, 1 July 2014-30 June 2019* (see Table 1, page 8).

[15] Ofgem, March 2013, *Price Controls Explained*, Factsheet 117, https://www.ofgem.gov.uk/ofgem-publications/64003/pricecontrolexplainedmarch13web.pdf .

duplication of specific projects or scoping of already undertaken projects. Reporting requirements geared towards such knowledge sharing could be in the form of a stakeholder forum or industry working group, to allow for the minimisation of project scope and learning duplication. As per the proposed implementation, there will be some risk of over reporting, particularly if the reporting requirements were to be similar across each of the platforms with little regard for the intended audience.

Time-limited nature of the innovation allowance

Innovation and the requirement for research and business integration should be considered as continuous in order to ensure prudent investment decisions. The NSW DNSPs consider that it would be appropriate for the Rules to specify a period of assessment and review of the scheme. At a minimum we suggest that the scheme should be allowed to operate for a period of 5-7 years before being reviewed. This would provide certainty around the intended application of the scheme.

Issue 4 Demand management incentive scheme

1. **If distribution businesses are able to receive a payment based on a proportion of the market benefits produced by a demand management project, is this likely to increase investment in projects that will deliver broader market benefits that are in the long term interests of consumers?**
2. **Given that the majority of distribution businesses are expected to be regulated under a revenue cap in the near future, is there value in amending the rules to explicitly require the inclusion of a payment for any foregone revenue resulting from implementing a demand management project approved under the innovation allowance? Should the AER retain discretion as to whether this component is appropriate?**
3. **In light of the recent changes to the distribution network pricing arrangements, what are the potential benefits of requiring that the DMEGCIS include tariff based demand management options, in addition to non-tariff based options?**

The impact of capturing market benefits

Introducing an incentive scheme, which allows DNSPs to capture a proportion of the market benefits from demand management projects will increase investment in business as usual demand management (BAU DM) projects. The realisation of market benefits will justify additional DM projects that are not cost effective to an individual network service provider (based on internal cost/benefit only), but cost effective to the NEM. This will deliver broader market benefits in the long term interest of consumers. Additionally, an incentive scheme will also drive greater utilisation of DMIA towards projects which will have tangible outcomes in the near future.

Impact of the revenue cap

As noted by the ENA, the form of regulation is a matter for separate decision by the AER in consultation with DNSPs within each review of the DNSP's framework and approach. Any new demand management scheme would need to provide the AER with a choice between the different forms of control available without consequential changes being required to amend the Rules governing the incentive schemes. The NSW DNSPs consider that it would be inappropriate for the Rules to explicitly or implicitly assume one form of regulation over another.

Consequently, while it is true that under a revenue cap a foregone revenue would not be necessary it should still be codified in the Rules so that the AER has the flexibility to incorporate this into the incentive scheme if in subsequent regulatory determinations it decided to change the form of control back to a WAPC.[16]

[16] The NSW DNSPS note that one of the factors that the AER must have regard to in developing the incentive scheme is the effect of the particular control mechanism applied to the DNSP this should operate to provide the AER with the ability to incorporate the foregone revenue requirement when relevant.

Why tariff based demand management options should be included under the incentive scheme and innovation allowance

The NSW DNSPs consider that it is in the long-term interests of electricity users for DNSPs to have incentives under the regulatory arrangements to undertake trials of innovative tariff structures. The insights gained from these trials will ensure that DNSPs make informed decisions about the future direction of tariffs. This in turn will provide customers, retailers, and other key stakeholders with an empirical basis upon which to better understand the potential short-term and long-term impacts of different network tariff structures.

Excluding tariff based demand management would unnecessarily limit the scope of the incentive scheme and place limitations on the demand management activities pursued by DNSPs. Each NSW DNSP has conducted a number of trials under the incentive scheme involving tariff based demand management. Further trials such as the ones outlined below would no longer be possible if the incentive scheme was limited to non-tariff based demand management only.

Examples of trials involving tariff-based or tariff-related demand management include:

- Ausgrid and Endeavour have conducted DMIA projects which involve investigating options for better utilising existing controlled load tariffs.
  - Ausgrid explored an approach of offering subsidised off peak tariff connections to our existing Controlled Load 1 and 2 tariffs for eligible electric hot water systems. The project included offering a modest subsidy for the electrical works associated with connecting a hot water system to our existing controlled load tariffs and explored marketing approaches and targeting the offer to localised parts of our network as well as targeting lower socio-economic households. The project was aimed at addressing existing market barriers, such as customer knowledge of the tariffs, associated savings and eligibility criteria for hot water systems (electric storage, solar-electric boost and heat pump);
  - Endeavour Energy is conducting a trial in selected parts of their network where pool owners have been allowed to connect their pool pump to the existing controlled load 2 tariff via a standard general purpose outlet (GPO) (previously hard-wiring was only allowed). The program allows participants to switch their pool pump energy supply from Domestic supply to Controlled Load 2 supply, saving them over 40% on their pool energy costs. This approach has been used successfully in Queensland but has not yet been proven in New South Wales.
- Ausgrid and Endeavour Energy have conducted air conditioner load control trials (CoolSaver) in selected parts of their networks (Rooty Hill, Glenmore Park, Lake Macquarie, Central Coast, Maitland) that have involved direct customer payments/incentives for allowing the DNSPs to activate the demand response mode in AS4755 compliant air conditioners on summer peak days. Although, these trials would not currently be categorised as “tariff” projects, there may be views that they are closely related. Furthermore if tariff options were excluded from the DMIS, it would be difficult to explore the potential of introducing a new controlled load tariff (or demand response tariff) option more applicable to air conditioner load control as an alternative to making direct customer incentives.
- Ausgrid and Endeavour Energy have both conducted dynamic peak rebate trials under DMIA funding. Endeavour Energy’s PeakSaver program was targeted at residential customers and involved payments to customers for reducing their peak energy usage under calculated baselines. Ausgrid conducted a similar trial targeting non-residential customers where demand response aggregators were used to contact customers in selected areas. Although, these trials would not currently be categorised as “tariff” projects, there may be views that they are closely related.
- Another category of tariff-based DM activities are new cost-reflective network tariffs that provide a better response from customers in reducing electricity use at times of peak demand. For example, as part of the Smart Grid Smart City program, Ausgrid partnered with the energy retailer, EnergyAustralia to trial the customer uptake and response to a range of new tariff options. These included cost-reflective tariffs such as critical peak pricing, seasonal time of use and dynamic peak rebates. Excluding tariff projects from the DMIS scope would make

it difficult to explore/ investigate the effectiveness of cost-reflective tariff options and market barriers associated with their implementation.

Precluding tariff based options from funding under the scheme limits the potential benefits to consumers from networks being able to better utilise existing network assets. Consequently, we consider it is in the long term interests of consumers and also consistent with the NEO for tariff based options to be included within the scope of the incentive scheme.

Section 2: Other issues

The rule change requests made by the proponents raise a number of issues which are not explicitly addressed by the AEMC's Consultation Paper questions. This section seeks to draw out these issues for further discussion. In particular, it is aimed at:

1) highlighting broader issues regarding the funding arrangements for demand management activities;
2) outlining aspects of the rule change request which are not appropriate or problematic; and
3) drawing attention to aspects of the rule change request which require further clarification or consideration.

The NSW DNSPs believe that further exploration of these issues will enable the AEMC to develop a Draft Rule which better achieves the NEO and the overarching policy intent for the rule change.

2.1 Clarifying funding arrangements for demand management projects

The NSW DNSPs consider that the uncertainty regarding the treatment of demand management projects under the regulatory determination process has discouraged DNSPs from pursuing cost effective demand management projects.

It is intended that the amended incentive scheme will remove disincentives on DNSPs utilising demand management. However, unless corresponding amendments are made to clarify DNSPs ability to obtain an allowance for demand management projects, as part of their regulatory determinations, the level of demand management activities undertaken by DNSPs will not increase materially and will be limited to those funded through capex deferrals or the DMIA or RIT-D.

The NSW DNSPs consider that this outcome contradicts the policy intent of both the rule change request and Power of Choice Review.

The proposed amendments by the proponents are primarily aimed at further encouraging DNSPs to undertake demand management projects. The amendments do not address the lack of certainty under the existing expenditure framework regarding:

- whether the AER can consider market benefits when assessing the efficiency of network expenditure allowances;
- the appropriate approach for accounting for capex/opex trade-offs for demand management expenditure; and
- how to treat/ assess projects which have a long term focus and straddle multiple regulatory periods.

The AEMC should make a more preferable rule to ensure that regulatory arrangements support DNSPs undertaking demand management projects. This is particularly relevant given COAG Energy Council's clarification that funding of projects under the DMIA is to be limited to new innovative projects and that business as usual (BAU) demand management is to be funded through the normal expenditure allowances provided by the AER under clause 6.5.6 and 6.5.7 of the Rules.[17]

The NSW DNSPs do not consider that this rule change is likely to result in a material increase in the level of demand management undertaken by DNSPs if the application of the current expenditure framework by the AER acts to preclude allowances for demand management. The NSW DNSPs consider that it appears to be contradictory to the long term interests of consumers for the AER to provide an allowance under the DMIA for DNSPs to trial the effectiveness of demand management

[17] COAG Energy Council (formerly SCER), *Reform of the demand management and embedded generation connection incentive scheme – rule change request*, December 2013, pp 6-7.

options and then preclude the DNSPs from obtaining an allowance under its regulatory determination to roll out projects which proved to be successful and cost effective.

Subsequently, we consider that there is a strong need for the AEMC to address this issue as part of this rule change request given the potential for perverse outcomes to occur and the overlapping nature of these related issues.

2.1.1 Consideration of market benefits

The NSW DNSPs note that while the COAG Energy Council rule change request touches on the issue of the regulatory treatment of demand management it does so solely in the context of the incentive scheme. Specifically, COAG Energy Council's proposed amendments are aimed at: [18]

- clarifying that BAU demand management projects should not be funded under the DMIA and should instead be funded from the normal expenditure allowances approved by the AER under clause 6.5.6 and 6.5.7 of the Rules; and
- clarifying that the AER is required to assess the prudency of demand management related expenditure in the same way as all other capital and operating expenditure at each regulatory reset.

These amendments do not remove the uncertainty regarding whether the AER can approve an expenditure allowance for projects that deliver wider market benefits, in addition to the distribution cost savings.[19] Whilst the COAG Energy Council rule change request clarifies that obtaining funding under the DMIA is to be subject to the same level of prudency as all other capital and operating expenditure, this clarification does not provide any further guidance or certainty on how the efficiency of demand management expenditure is to be assessed.

Consequently, the NSW DNSPs consider that the recommendation outlined in the AEMC's Power of Choice Review to amend the Rules to clarify that the AER is able to consider potential non-network benefits when assessing the efficiency of the proposed demand management project included in the business' revenue proposal, is progressed as part of this rule change request.

This approach is consistent with the approach outlined in the AEMC's Power of Choice Review, where it noted that this recommendation should be implemented through the rule change aimed at amending the incentive scheme given the overlap between the issues.[20] The NSW DNSPs do not consider the proposed amendment to clarify the AER's ability to consider potential non-network benefits to be controversial given that it was requested both by DNSPs and the AER. In addition, the amendment was considered to be minor by the AEMC.

As noted by the AEMC, the proposed amendment would work by clarifying that the AER can have regard to the potential for the network business's expenditure to deliver market benefits, with the term 'market benefit' being defined with reference to the RIT-D, when considering how a business' proposed expenditure meets the operational and capital expenditure criteria. [21]

Clarifying the AER's ability to take into account market benefits when assessing demand management expenditure is likely to have a positive impact on the level of demand management undertaken by DNSPs as:

- DNSPs will be encouraged under the amended incentive scheme to pursue more demand management opportunities due to the incentive to capture a portion of the broader market benefits delivered by the project; and
- the ability to take into account market benefits will better enable DNSPs to build positive business cases and substantiate the efficiency of the demand management projects to the AER in order to obtain an expenditure allowance under its regulatory determination.

Consequently, this proposed amendment is consistent with both policy intent for the current rule change and the NEO, as it promotes the efficient operation, use of and investment in electricity

[18] COAG Energy Council (formerly SCER), *Reform of the demand management and embedded generation connection incentive scheme – rule change request*, December 2013, pp 6-7.
[19] This arises as the expenditure criteria only refer to the need for projects which relate to network performance, network reliability and meeting local network demand.
[20] AEMC, *Power of choice review – giving consumers options in the way that they use electricity,* Final Report, 30 November 2012, Chapter 7, pp 226-227.
[21] Ibid, p 226.

services. We consider that it would be appropriate for this amendment to be implemented as a more preferable rule (as opposed to a separate rule change) given the overlapping and related issues and complementary nature of the proposed amendment.

2.1.2 Clarifying opex/capex trade-offs under the regulatory framework

The NSW DNSPs consider that further examination of the treatment of opex/capex trade-offs under the regulatory framework is required. In particular, we are concerned that the AER's current approach to accounting for the capex/opex trade-off acts as a barrier to greater uptake of demand management projects.

As noted by ENERNOC in its submission in response to the AER draft determinations for the NSW DNSPs, there are broadly two ways to consider the capex/opex trade-off from demand management expenditure[22]:

- **Option A:** Make an explicit allowance for the opex required for demand management, and reduce the capex allowance reflect the resulting savings; and
- **Option B**: Ignore the possibility of demand management when setting the opex and capex allowances, such that the DNSP will then fund demand management initiatives out of the money that the incentive framework allows it to keep for reducing capex.

Under the current Rules it is unclear which approach is appropriate. The NSW DNSPs are concerned that the AER's approach for accounting for capex/opex trade-offs reflects Option B, whereas the more appropriate approach which should be reflected in the Rules is Option A.

The AER's proposed approach towards accounting for capex/opex trade-offs is evident by its recent decision on demand management in the NSW DNSPs draft determination.

In proposing an opex allowance for demand management expenditure, the NSW DNSPs adjusted their capex forecasts to cater for the expected capex deferrals from undertaking the proposed demand management projects. In assessing the opex allowance for demand management expenditure the AER did not appear to take the capex deferrals into account and instead imposed additional reductions to network investment and non-network investment without separately or clearly assessing the demand management activities proposed by each DNSP.[23]

The AER did not include in the NSW DNSPs draft determination an explicit reference in the capex or opex forecasts for demand management. Rather, the AER formed the view that it is most appropriate to rely on the incentive framework, together with the new requirements around the RIT-D and the DAPR, to drive the efficient use of demand management and share the benefits with consumers through the capital efficiency sharing scheme (CESS). [24]

It is important that the Rules clarify the appropriate approach towards accounting for capex/opex trade-offs from demand management as it appears that the AER's preferred approach under the framework is Option B. This approach limits the DNSP's ability to undertake demand management projects to those undertaken in accordance with the RIT-D or incentive scheme. This outcome contradicts the overarching objective of the rule change and is contrary to the NEO, as it constrains DNSPs' ability to pursue cost effective demand management projects as an alternative to network investment.

Where the AER did consider the capex/opex trade-off from demand management expenditure, it did so in an inappropriate manner, whereby it contemplated imposing capex offsets for demand management without taking into account the efficiency of projects proposed by DNSPs as part of their demand management proposal.

For example the AER stated that it[25]:

> *..considered whether it is appropriate for us to determine an explicit amount of capex that could be deferred through demand management, based on the scale and positive outcomes achieved by Ausgrid during 2009–14 and the Productivity Commission report. Using this*

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[22] ENERNOC, Submission on 2015-19 draft decisions and revised proposals for NSW DNSPs, 13 February 2015, p 5.

[23] AER, Draft decision*, Endeavour Energy distribution determination 2014-19 – Attachment 6: Capital Expenditure*, November 2014.

[24] Ibid, p 6-75.

[25] Ibid, p 6-76.

> *approach we could apply an explicit systems capex forecast offset for Endeavour of 9.2%, or approximately $93 million ($2013–14). However, we would also need to assess the efficient opex required to support this capex offset.*

It is evident from the above statement that the AER intends to consider the capex/opex trade-offs associated with demand management for the purpose of mandating demand management outcomes as opposed to assessing the efficiency of the expenditure proposed by DNSPs. Whilst the AER has not utilised such an approach to date, we consider its application would provide further disincentives for DNSPs conducting demand management activities.

Proposed demand management expenditure should be assessed for its efficiency and prudency. It is not appropriate to prescribe a level of demand management based on an expectation that previous non-network investment in different areas and under different circumstances can be replicated in future periods. Such an arbitrary approach would result in inefficient allowances which over/under compensate DNSPs and establish unrealistic targets.

The NSW DNSPs strongly urge the AEMC to examine this issue further. We consider that the Rules need to be amended to provide further guidance to the AER on how it is to assess demand management expenditure and takes into account the capex/opex trade-off from approving an allowance for demand management expenditure. It is important to address this issue to ensure that the amendments to the incentive scheme have their desired effect and that the regulatory framework supports the efficient uptake of demand management consistent with the NEO.

2.1.3 Assessing demand management projects which straddle multiple regulatory periods

It was previously identified as part of the Power of Choice Review that it was unclear under existing arrangements how expenditure for projects which straddle multiple regulatory periods should be assessed. The AEMC decided against recommending amendments to the Rules to address this issue based on feedback from the AER.[26]

However, the AEMC considered that it might be useful, as a means of reducing uncertainty for businesses, for the AER to consider issuing some principles or guidelines regarding the factors that it would take into account when considering the efficiency of a DSP project expenditure at the time of a reset. [27]

The NSW DNSPs strongly support this approach and urge the AEMC to amend the Rules to reflect this. It is important that the Rules provide the DNSPs with greater certainty with regards to how the efficiency of demand management expenditure (particularly projects which have a long term focus) will be assessed. This is particularly relevant given that the amended incentive scheme is aimed at encouraging DNSPs to undertake projects which are focused on delivering long term benefits to consumers and the AER's recent approach towards assessing demand management expenditure.

2.1.4 Summary

The NSW DNSPs consider that in order for the proposed amendments under the incentive scheme aimed at encouraging DNSPs to undertake demand management to be effective, corresponding amendments to the Rules aimed at better supporting DNSPs' ability to obtain funding for demand management activities need to also be implemented.

We suggest that these issues could be addressed by adopting previous recommendations made by the AEMC in its Power of Choice Review, namely:

- clarifying the ability of the AER to have regard to the potential for the network businesses expenditure to deliver market benefits when considering how a business' proposed expenditure meets the operational and capital expenditure criteria; and
- including a requirement for the AER to issue principles or guidelines regarding the factors that it would take into account when considering the efficiency of a DSP project expenditure at the time of a reset.

In addition, we consider that additional amendments to the Rules are also required to clarify the appropriate approach for accounting for capex/opex trade-offs from approving demand management

[26] AEMC, *Power of choice review – giving consumers options in the way that they use electricity,* Final Report, 30 November 2012, Chapter 7, p 229.
[27] Ibid.

expenditure. Further, we note that it was previously anticipated by the AEMC in its Power of Choice Review that these amendments would be made as part of the rule change to amend the incentive scheme given the overlapping nature of issues raised by the proposed amendments.

The NSW DNSPs consider that making these amendments is consistent with the NEO and assists in achieving the overarching policy for the rule change request which is to ensure that regulatory arrangements adequately encourage and support DNSPs undertaking demand management.

2.2 Other issues raised by the rule change requests

The NSW DNSPs have identified a number of aspects of the rule change request which we consider are either inappropriate or problematic. These include:

- codifying a maximum share of non-distribution benefits available for reward for pursuing demand management projects is not appropriate and adds unnecessary prescription to the design of the incentive scheme. We consider a more appropriate approach would be for this to be examined as part of the AER's development of the DMIS;
- references to "material change" is problematic and may unnecessarily limit the scope of the scheme by making access to the incentives under the scheme too difficult for DNSPs if this threshold is set to high;
- TEC's proposal to amend the capex and opex objectives to maximise the prudent and efficient use of non-network alternatives is inappropriate. Demand management is one possible solution available for DNSPs to meet and manage expected demand. It is not appropriate to mandate the use or adoption of non-network alternatives, as this would have the effect of elevating or codifying one possible solution (and one that may be higher cost) for meeting or managing expected demand which in itself is contradictory and undermines the NEO.

2.3 Issues requiring further clarification

The NSW DNSPs seek further clarification from the AEMC on how the terms "business as usual" and "uniqueness/novelty of a proposed project" are to be interpreted under the amended incentive scheme.

The NSW DNSPs are concerned that a subjective interpretation of "uniqueness" for the DMIA scope and criteria could potentially limit the scope of the DMIA projects depending on how it is applied by the AER. We have listed some examples of projects which may or may not be considered unique depending on interpretation approach adopted:

- air conditioner load control programs have been undertaken worldwide and by other Australian DNSPs successfully (including Energex's PeakSmart program). It could be considered that the NSW DNSPs air conditioner load control programs would not be considered unique in this context. However, this option has not yet been proven in our network as being a cost-effective demand reduction option and the main aim of these programs is to test the cost-effectiveness of this option as it relates specifically to the NSW DNSPs; and
- grid battery projects have also been undertaken globally and by other Australian DNSPs and there would be similar concerns regarding the AER's interpretation of "uniqueness" in regards to these types of projects.

In addition, there are a number of DMIA projects that could be considered as "business as usual" depending on how the term is interpreted which may make them ineligible for funding under the DMIA. In these cases, project objectives may be more targeted at investigating new and innovative ways of addressing existing market or technology barriers that prevent the efficient uptake of these "business as usual" DM options. Some examples include:

- testing incentive levels and different engagement approaches to customers for encouraging the installation of Power Factor Correction equipment;
- testing customer incentives, education and different engagement approaches to customers for encouraging the uptake of existing controlled load tariffs or new cost-reflective tariffs; and
- making improvements to the control of customers load on existing tariffs to optimise demand reductions in summer.

Attachment 1 – The complimentary nature of cost reflective pricing and enabling technologies upon DNSP demand management

Cost reflective pricing impacts

DNSP demand management, particularly broad based demand management, is not only cost effective on its own but is also complementary with any cost reflective pricing introduced by distribution networks and electricity retailers. DNSP demand management programs support two key gaps in the ability of cost reflective pricing to effectively defer network investment. These gaps are:

1) n the near to medium-term, tariff changes are unlikely to have a sufficient impact to be effective in deferring localised constraints.
2) Without enabling technologies, cost reflective tariffs are unlikely to be sufficiently effective on their own.

Medium term effectiveness of cost reflective pricing

The impact on customer peak demand from the introduction of cost reflective pricing will be highly dependent upon the:

- roll-out of any required metering;
- structure of future tariffs;
- period of time required to fully introduce effective tariffs;
- level that any price signal is passed though in retail pricing;
- capacity of the network and whether underlying peak demand is increasing, remaining flat or decreasing;
- customer response; and
- effectiveness of cost reflective pricing in deferring network augmentation.

Before customers can select cost reflective tariffs, these tariffs must be offered to customers, customers or their agents will need to invest in the necessary metering and networks and retailers will need to upgrade the necessary IT infrastructure. From our experience, this takes considerable time even under a mandatory rollout. By way of example, Ausgrid introduced interval meters as their default meter in 2003[28] and have 442,407 customers on time of use pricing, out of its customer base of 1.6 million customers.[29] To achieve this, both the interval meters and time of use pricing were mandatory for customers using more than 15,000 kWh pa and for new and replacement meters. Ausgrid now has the largest application of cost reflective tariffs of any distributor in Australia. But, this took ten years of focused effort.

Ausgrid's experience over the past ten years is that most customers perceive cost reflective tariffs as punitive, often regardless of whether they benefit financially. Building a level of trust in the community will not be straightforward. Innovative tariffs will only be accepted by customers when they perceive an advantage to being on those tariffs and customers will need some confidence that they will benefit. Smart meters offers the capability to allow customers to discover which tariffs offer the most benefit, but without a mandatory rollout, this will take some time. Until such meter offers are made to customers, it is unclear how quickly or slowly smart meters will be selected by consumers.

It also does not immediately follow that cost reflective tariffs will be applied as a consequence of smart meters being installed. In Victoria where smart meters have now been installed to the vast majority of customers under a DNSP led roll out, there has been minimal take up of time of use pricing. For example out of AGL's customer base of 454,500 domestic customers, only 831 customers voluntarily selected flexible pricing in the first 7 months that it was offered to customers from the Victorian launch date of 1 Sep 2013 (Sep 2013- April 2014). This is a take up rate of 0.3% per annum. We note that nearly all customers were able to voluntarily take up flexible pricing due to almost full coverage of smart meters across Victoria.

[28] Type 6 (accumulation) meters are now the default meter for residential customers. Ausgrid has 480,000 customers with interval meters.
[29] Ausgrid's default tariff for residential customers is the inclining block tariff.

With a market led roll out of cost reflective pricing and smart meters, we would anticipate an even lower penetration than AGL's numbers due to customers needing to have their meter replaced and possibly pay for the costs as well as take up a new pricing offer they may not be familiar with.

A further impact on the effectiveness of cost reflective pricing is that any price signal perceived by the customer is often diluted and can moderate any customer response. The Productivity Commission noted when examining rates in NSW that "*a ten-fold price differential at the network side was more than halved when expressed in retail prices. This dilution of network charging variations is important in modelling demand responses.*"[30]

The combination of a:

- market led smart meter roll-out
- the likely gradual introduction of cost reflective tariffs
- the level that any price signal is passed though in retail pricing, and
- the ineffectiveness of broad market tariffs to influence customers in areas with emerging constraints

will dilute and delay a customer response sufficient to effectively defer network investment in the near to mid-term.

Enabling technologies

The absence of appropriate enabling technologies restricts the customer's ability to respond to cost reflective tariffs. DNSP demand management programs introduce enabling technologies to allow customers to effectively respond to price signals and reliably reduce their electricity use at peak time.

That is, even if consumers faced perfectly cost reflective tariffs today, they would still need support to respond to those tariffs through technology enablement. Customers using up to 100 MWh p.a. have limited capacity to change their behaviour to cost reflective tariffs. The use of broad based demand management using enabling technology maximises the customer's capacity to respond to these tariffs. Broad based demand management can be rolled out in the absence of cost reflective tariffs as well.

Enabling technologies introduced as part of a DNSP's demand management program is a key plank in maximising the benefits of cost reflective prices. For example, a program to control customer's air conditioners will extract far more demand management benefit than simply a tariff because the technology provides the needed demand response to the tariff that the consumer may have difficulty in responding to. Electricity consumers are more likely to participate by reducing demand when, not only are they given the problem of a cost reflective price, but also a solution to that problem in the form of a technology solution that is managed on their behalf and does not require them to have concentrated ongoing engagement.

Furthermore, demand management programs are designed to be effective with or without new cost reflective tariffs, smart meters or updated back-end infrastructure. In the event that these elements are delayed, the demand management programs can still reliably deliver the demand reductions so as to defer network investment. Delaying the complementary benefits of demand management by assuming a theoretical outcome from cost reflective pricing and meter competition would not be in the long term interests of consumers.

[30] Productivity Commission, 2013, The costs and benefits of demand management for households, p 7