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23 February 2017

Mr Warwick Anderson
General Manager
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

Dear Mr Anderson

***Consultation Paper: Demand Management Incentive Scheme and Innovation Allowance Mechanism.***

Ausgrid welcomes the opportunity to provide this submission in response to the Australian Energy Regulator's (AER) *Consultation Paper: Demand Management Incentive Scheme and Innovation Allowance Mechanism.*

The AER has published a comprehensive *Consultation Paper* reflecting the breadth of options available to develop a new demand management scheme (Scheme) and innovation allowance mechanism (Allowance Mechanism). We look forward to working with the AER and other stakeholders in identifying improved incentives and funding models for the deployment of efficient demand management.

***Our preferences***

Of the options presented in the AER's *Consultation Paper*, Ausgrid's strong preference is for the implementation of a net–market benefit sharing scheme. We have previously designed and sought approval for a scheme of this type. In our experience, the measurement of net–market benefits can be accurately performed, and should not be considered a barrier to implementation. With respect to the Allowance Mechanism, we have proposed a hybrid arrangement that combines a low and a high cap funding model. We consider the combination of these options would best achieve the Allowance Mechanism objective by encouraging both small and large scale research and development.

Ausgrid is apprehensive about some of the options in the AER's *Consultation Paper*. In terms of the Scheme, Ausgrid would not support the introduction of targets. Our view is that a scheme of this type would not be workable. This is because any targets would be based on a distributor's requirements at a particular point in time, which are subject to change as a result of modifications in customer demand or new information. In relation to the Allowance Mechanism, we are concerned about the complexity associated with options that include complicated bidding arrangements. Our preference is for a simple, easy to administer funding model.

***Demand management opportunities***

We acknowledge that in recent years the volume of demand management projects in the NEM may have been below the expectations of some stakeholders. As outlined in our submission, the key driver of this on our network has not been the incentives available under the existing regulatory framework, but the limited opportunities for demand management in the current environment of depressed load growth.

Over the next 5 to 10 years, Ausgrid expects the moderation in peak demand to continue. In these circumstances the dominant driver of our capital investment will be how we respond to aging assets and the associated risks of equipment failure. We encourage the AER to take this into account in the development of the Scheme and Allowance Mechanism.

Our view is that investments which are made to defer the retirement or replacement of aging assets can offer opportunities for 'non–network options relating to demand management'. When assets approach the end of their serviceable life, distributors may have an option to defer retirement or replacement by investing in non–network solutions which address risks associated with equipment failure. In our view, a well–designed Scheme and Allowance Mechanism would take these challenges into account.

Ausgrid's submission on each of the questions in the AER's *Consultation Paper* is set out in Appendix A and B. In support of our position, and to demonstrate the challenges distributors face when considering non–network options relating to aging assets, we have included a case study in Attachment C. This case study is illustrative of the significant potential the Scheme and Allowance Mechanism has with respect to non–network solutions which manage demand at aging assets.

If you have any queries or wish to discuss this matter in further detail please contact Joe Pizzinga on (02) 9269 2121 or via email jpizzinga@ausgrid.com.au.

Yours sincerely

**RICHARD GROSS**
Chief Executive Officer

## Attachment A – Summary of our submission

| | Question | Response |
|---|---|---|
| 1 | Do stakeholders support our interpretation and proposed implementation of the new rules? If you have alternative view, please share these and provide supporting evidence. | We have some concerns with the AER's interpretation and proposed implementation of the new rules.<br><br>In its *Consultation Paper*, the AER sets out additional criteria which are not included in the new rules. We are concerned about the application of the first of these additional criteria, which the AER terms "enhancing competition". In developing the Scheme and Allowance Mechanism, our view is that it is incumbent on the AER to apply the principles in clauses 6.6.3(c) and 6.6.3A(c). These principles make no mention, either expressly or implicitly, to enhancing competition. |
| 2 | Do you agree with our view on the main demand management incentives (or disincentives) provided under the regulatory framework and the potential issues associated with these incentives? Please provide reasons to support any alternative views you may have. | We acknowledge that in recent years the volume of demand management projects in the NEM may have been below the expectations of some stakeholders. In our view, the key driver of this has not been the incentives available under the existing regulatory framework, but the limited opportunities for demand management in the current environment of depressed load growth. |
| 3 | Do you see value in exploring the net–market benefit sharing mechanism further, despite the difficulties associated with measuring net–market benefits? If yes, what detail of guidance should we provide on calculating market–wide costs and benefits? Should we (and if so, how should we) establish a method for valuing smaller demand management projects in a way that reduces the administrative burden of applying the Scheme to these projects? | Our preference is for the development of a net–market benefit sharing scheme. In our experience, the measurement of net–market benefits can be accurately performed, and is not a barrier to implementation.<br><br>We sought approval of a net–benefit sharing scheme in our 2014–19 regulatory proposal. |
| 4 | Since the RIT–D already requires distributors to select the option with the highest total market benefit, should we (and if so, how should we) treat RIT–D projects differently under this type of Scheme? | Any treatment of RIT–D projects differently under the Scheme would place substantial limitations on the non–network options distributors are able to undertake. This would not be in the long term interests of consumers or in accordance with the objective/principles set out in the new rules. |
| 5 | How might we best combine the mechanisms discussed in section 6 above into an option that achieves the Scheme's objective? If you prefer a mechanism that we did not discuss in section 6, please provide details of this mechanism. | We have a strong preference for a net–market benefit sharing scheme. This preference is supported by 6.6.3(c)(3) of the new rules which provides that in the development of the Scheme the AER is to 'take into account the net economic benefits delivered to all those who produce, consume and transport electricity in the market'. In our view, |

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| | | this places a net–market benefit sharing scheme in a superior position compared to the other options under consideration, which are not based on a sharing of market benefits. This approach provides a clear and administratively simple incentive scheme for all parties. |
| **6** | If you have views against applying any of the particular mechanisms discussed in section 6, please provide reasons to support this view. | We would not support the introduction of a scheme based on targets. Our concern with the setting of such targets is that they would be based on a distributor's requirements at a particular point in time. This ignores the fact that network planning is a continuous process. Though network investment may be forecast several years into the future, often there can be deviations in such forecasts as a result of changes in customer demand. |
| **7** | How might we best give effect to or enhance the information and reporting requirements discussed in section 6.5 above? | Our general view is that any onerous reporting requirements should be avoided while any steps that can be taken to streamline reporting, such as pro–forma reports or spreadsheets, should be explored. |
| **8** | Which of the options discussed above in section 7 would best achieve the Allowance Mechanism's objective? Please provide reasons supporting your view. If you prefer an Allowance Mechanism design that we did not discuss as an option in section 7, please provide details of this option. | In our view, the AER should design an Allowance Mechanism which combines, with some refinements, options 1 and 2. We consider the combination of these options would best achieve the Allowance Mechanism objective by maximising the efficient research and development of both small and large cap demand management projects. |
| **9** | If you have views against applying any of the particular mechanisms in section 7, please provide reasons to support this view. | We are concerned about the complexity associated with options that include complicated bidding arrangements. Our preference is for a simple, easy to administer funding model. |
| **10** | How might we best give effect to or enhance the information and reporting requirements discussed in section 7.5? | We broadly support the approach to information and reporting requirements outlined in section 7.5 of the AER's *Consultation Paper*.<br><br>We encourage the AER to adapt its reporting requirements according to the expenditure that is recovered. While high cap projects may require a certain level of additional oversight, Ausgrid considers the information and reporting requirements for low cap projects should be relatively streamlined. |

# Attachment B – Our response to the consultation questions

## Question 1

## Do stakeholders support our interpretation and proposed implementation of the new rules? If you have alternative views, please share these and provide supporting evidence.

Ausgrid welcomes the opportunity to comment on the AER's interpretation and implementation of the new rules. In our view, the AEMC's final rule sets out a clear set of principles the AER must take into account. The AER should apply those principles in developing the Scheme and Allowance Mechanism, without introducing any further criteria.

***Proposed additional criteria***

In its *Consultation Paper*, the AER sets out additional criteria which are not included in the new rules. We are concerned about the application of the first of these additional criteria, which the AER terms "enhancing competition". In developing the Scheme and Allowance Mechanism, our view is that it is incumbent on the AER to apply the principles in clauses 6.6.3(c) and 6.6.3A(c). These principles make no mention, either expressly or implicitly, to enhancing competition.

We are concerned that the introduction of an "enhancing competition" criterion may lead to a Scheme and Allowance Mechanism that does not reflect the intentions of the AEMC. In the course of the AEMC's consultation, Ausgrid notes that the AER made a submission advocating for the new rules to address the 'potential for demand management to be provided on a competitive basis by other service providers'.[1] The AEMC took this submission into account, but declined to include a competition based criterion in the new rules. It reasoned: 'The Commission considers that distribution business will always need to be the decision makers with regard to whether a network or non–network option provides the most efficient solution to address a constraint on their networks'.[2] We agree with this statement and support the AEMC's reasoning.

Ausgrid is wary of the potential consequences of the AER introducing a competition based criterion to the development of the Scheme and Allowance Mechanism. We are particularly concerned about that criterion reducing the existing level of flexibility in the type and scope of arrangements electricity distributors can consider in the delivery of efficient services. Our view is that a reduction in such flexibility in an attempt to enhance competition would undermine the current regulatory framework, add additional costs, and would not be in the long term interests of customers.

We also question whether it is necessary to introduce an "enhancing competition" criterion. In our experience, contracting with demand management service providers in the contestable market has always been the primary method for delivering non–network solutions that have deferred, avoided or managed the risk associated with a network investment. Under the previous Demand Management Incentive Scheme in NSW, known as the "D-factor scheme", Ausgrid delivered more than 30 demand management projects during a 10 year period between the years of 2004–05 to 2013–14. Over 80 percent of Ausgrid's demand management implementation costs for these projects were sourced from external service providers. These included providers of customer power factor correction equipment, embedded generator services, and customer energy efficiency equipment and services.

In our view, a competition based criterion should not be applied in the development of the Scheme and Allowance Mechanism. We note that the AER's *Consultation Paper* included two further additional criteria. These were that the Scheme and Allowance should be transparent to apply and simple and administratively straightforward. We consider these factors are not directed at the actual

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1 AER, *Submission on demand management incentive scheme rule changes*, 9 July 2015, p. 2.

2 AEMC, *Rule determination: National electricity amendment (Demand management incentive scheme) Rule 2015*, 20 August 2015, p. 102.

substance of the Scheme and Allowance Mechanism, but the quality of their design and implementation. In terms of quality, we agree that the regulatory mechanisms the AER develops should be transparent, simple and administratively straightforward.

***Areas of clarification***

We seek greater clarity from the AER about its interpretation of two aspects of the new rules. These relate to power factor correction (PFC) projects and the scope of non–network options covered by the Scheme. At the next stage of consultation, we request that the AER clarifies whether:

1. the AER considers all PFC projects are excluded from the scope of clause 6.6.3
2. the scope of the Scheme and Allowance Mechanism will include non–network options which, by managing demand risks associated with equipment failure, defer the retirement or replacement of aging assets.

In our view, the scope of clause 6.6.3 is not so narrow that it excludes all PFC projects, as the AER's *Consultation Paper* suggests.[3] We consider non grid–side, customer PFC programs fall within the scope of the Scheme because they reduce the load on an electricity distributor's assets through a lowering of demand for amperage. To maximise the options available to electricity distributors under the Scheme and Allowance Mechanism, Ausgrid's view is that the challenges associated with aging assets should be included in the AER's reforms. Further details about these types of non–network solutions are outlined in Appendix C of our submission.

## Question 2

### Do you agree with our view on the main demand management incentives (or disincentives) provided under the regulatory framework and the potential issues associated with these incentives? Please provide reasons to support any alternative views you may have.

We understand that the AER and other stakeholders may have concerns that the current regulatory framework creates a bias towards expenditure on network investment over non–network options.

The traditional view of demand management involves reducing the peak demand a network reaches over a handful of days in the course of a year. Generally speaking, this involves electricity distributors investing in solutions that defer or avoid the requirement to augment or otherwise increase the capacity of their networks. It follows that where growth in peak demand has declined or flattened, there will be little or no requirement for electricity distributors to augment the network or pursue alternative demand management options. This has been the case in recent years.

As noted in the AER's *Consultation Paper*, only nine RIT–Ds have been finalised by electricity distributors since January 2014. This demonstrates that non–network options equivalent to augmenting the distribution network at a cost of at least $5 million has been very limited. We encourage the AER to take this into account and find that the apparent lack of demand management activity is primarily driven by the moderation in peak demand, rather than any material deficiencies in the incentives offered under the current regulatory framework.

To the extent that improvements can be made, Ausgrid supports regulatory mechanisms that provide a financial incentive to factor in the broader market benefits which arise from distributors making non–network investments and to trial innovative non–network solutions. We, however, caution against attributing too much responsibility for the lack of demand management to the current regulatory framework. In our view, the regulatory mechanisms the AER develops must be proportional to the issues at hand. We are concerned that if any deficiencies associated with the current regulatory framework are overstated, then the regulatory mechanisms the AER develops will be disproportional to the issues they are attempting to address.

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3 AER, *Consultation paper: Demand management incentive scheme and innovation allowance*, January 2017, p. 4–21.

## Question 3

### Do you see value in exploring the net–market benefit sharing mechanism further, despite the difficulties associated with measuring net–market benefits? If yes, what detail of guidance should we provide on calculating market–wide costs and benefits? Should we (and if so, how should we) establish a method for valuing smaller demand management projects in a way that reduces the administrative burden of applying the Scheme to these projects?

Our preference is for the development of a net–market benefit sharing scheme. We have previously designed and sought approval for a scheme of this type. In our experience, the measurement of net–market benefits can be performed, and is not a barrier to implementation.

We sought approval of a Demand Management Benefit Sharing Scheme (DMBSS) as part of our 2014–19 regulatory proposal. The DMBSS was designed to give both Ausgrid and consumers a share in the upstream benefits of demand management projects. In measuring such benefits, we applied a $100 per kVA incentive ($2013–14). Via this incentive rate Ausgrid would have received 50 percent of the net–market benefits associated with demand management projects, whilst consumers would have received the remaining 50 percent through lower transmission and generation charges reflected in their retail energy bills. Even though the DMBSS received strong support from stakeholders such as the University of Technology Sydney and EnerNOC, the AER did not approve our proposal. This was on the basis that the AEMC's demand management rule change had not been finalised by the time the AER made its decision. Now that the AEMC has made its final rule, we are of the view the AER can implement an incentive scheme similar to the DMBSS.

We understand that the AER may have concerns about potential difficulties associated with measuring net–market benefit. In our view, net–market benefits are capable of robust calculation. The incentive rate included in our DMBSS proposal was based on analysis performed by an engineering consultant, AECOM.[4] The methodology it applied involved estimating the long run marginal cost of each element of the downstream market to a distribution system. Using this approach, AECOM found that the average cost of increasing the capacity of the transmission network and a peaking generation plant were $90 per kVA and $95 per kVA, respectively. In our 2014–19 regulatory proposal, we rounded up the average of these costs to derive the $100 per kVA incentive rate applied in the DMBSS. In that way, the reward under the scheme reflected the avoided capital costs to generation and transmission from undertaking demand management investments on our section of the electricity supply chain.

## Question 4

### Since the RIT–D already requires distributors to select the option with the highest total market benefit, should we (and if so, how should we) treat RIT–D projects differently under this type of Scheme?

We would not support the AER treating RIT–D projects differently under the Scheme. Any exclusion, restriction or otherwise different treatment of projects which exceed the $5 million RIT–D threshold would substantially limit the opportunities of electricity distributors to employ non–network options relating to demand management. In our view, such limitations would not be consistent with the objectives of the new rules or in the long term interests of consumers. We consider that the introduction of a new demand management scheme will complement and further encourage the existing obligations on distributors to examine non–network options as part of the RIT–D process.

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[4] AECOM, *Impact of electric vehicles and natural gas vehicles on the energy markets*, 6 December 2011.

## Question 5

### How might we best combine the mechanisms discussed in section 6 above into an option that achieves the Scheme's objective? If you prefer a mechanism that we did not discuss in section 6, please provide details of this mechanism.

We have a strong preference for a net–market benefit sharing scheme. Out of all the scheme types in the AER's *Consultation Paper*, it would best meet both the objective and the set of principles in clause 6.6.3 of the new rules. In terms of the design features of the net–market benefit sharing scheme, we encourage the AER to implement a scheme similar to the DMBSS discussed in our response to question 4 above.

Ausgrid's preference for a net–market benefit sharing scheme is supported by clause 6.6.3(c)(3) of the new rules. It specifically provides that in the development of the Scheme, the AER is to 'take into account the net economic benefits delivered to all those who produce, consume and transport electricity in the market'. The DMBSS design clearly gives effect to this principle by offering a share in the transmission and generation costs that are avoided when an electricity distributor undertakes a demand management project. In terms of giving effect to the new rules, the DMBSS or a similar net–market benefit sharing scheme is a superior option compared to the other schemes under consideration, which are not based on a sharing of downstream benefits.

Our preference is for the DMBSS or a similar net–market benefit sharing scheme. We nonetheless offer in principle support for an alternative scheme based on a revenue "uplift" added to the amount actually spent on demand management projects. The NSW "D-Factor" demand management incentive scheme, which Ausgrid applied to deliver 30 demand management projects over a 10 year period, used this approach to incentivise demand management. As the AER outlined in its *Consultation Paper* regarding Type 1 options, we consider an "Uplift Scheme" could be based on providing incentives reflecting the return on capital a distributor foregoes over one or two regulatory periods. Alternatively, an Uplift Scheme could be based on the actual operating expenditure associated with the implementation of demand management projects with a revenue uplift which has been determined by the AER to offer efficient incentives. This may operate similar to the Network Capability Improvement Incentive Scheme, which offers transmission business $1.5 dollars for every $1 spent on "low cost–high value" options.

## Question 6

### If you have views against applying any of the particular mechanisms discussed in section 6, please provide reasons to support this view.

As outlined in our response to question 5 above, our preference is for the AER to implement a scheme similar in structure to the DMBSS. If it or a similar net–market benefit sharing scheme was not put into effect, then of the alternatives in the AER's *Consultation Paper* we would be particularly concerned about the "Type 4: Targets for demand management deployment".

As a prerequisite to the Type 4 Scheme, the AER would have to set targets for each electricity distributor. Our concern with the setting of such targets is that they would be based on a distributor's requirements at a particular point in time. This ignores the fact that network planning is a continuous process. Though network investment may be forecast a number of years into the future, there can be deviations in such forecasts as a result of changes in customer demand or other new information. This can lead to a material variation or even the entire removal of a previously identified investment need.

We conclude that a Type 4 Scheme based on targets for demand management deployment would face substantial implementation challenges. With the energy sector experiencing considerable change, a demand management scheme based on demand reduction targets would risk introducing significant regulatory uncertainty and, in our view, is unlikely to be workable. We are also concerned that the setting of targets may lead to inefficient outcomes. To identify and implement the least cost solutions, distributors must operate in an environment where they can be flexible in the planning and investment decisions they make. Our concern is that the introduction of rigid targets may disrupt that flexibility and lead to less efficient planning and investment outcomes.

## Question 7

### How might we best give effect to or enhance the information and reporting requirements discussed in section 6.5 above?

Regardless of the type of scheme the AER implements there will be an element of pre and post project reporting. In developing the information and reporting requirements of the Scheme, we encourage the AER to consider the cost to electricity distributors of investing in new processes and systems. Our general view is that any onerous information requirements should be avoided while any steps that can be taken to streamline reporting, such as pro–forma reports or spreadsheets, should be explored. To facilitate regulatory certainty, we consider there to be value in the development of a guideline specifically setting out the information that the AER requires.

## Question 8

### Which of the options discussed above in section 7 would best achieve the Allowance Mechanism's objective? Please provide reasons supporting your view. If you prefer an Allowance Mechanism design that we did not discuss as an option in section 7, please provide details of this option.

In our view, the AER should design an Allowance Mechanism which combines, with some refinements, options 1 and 2. We consider the combination of these options would best achieve the Allowance Mechanism objective by maximising the efficient research and development of both small and large cap demand management projects.

To combine options 1 and 2, the structure of the Allowance Mechanism could be divided into a "Part A" and "Part B". Under Part A, the AER could give effect to arrangements similar to those described in option 1. This would entail a 'minor extension of the status quo' where electricity distributors are given an ex–ante allowance for each year of a regulatory control period. To supplement this, Part B would then give effect to arrangements similar to option 2 in the AER's *Consultation Paper*. This would allow distributors to apply to the AER for an ex–ante allowance for individual demand management projects. Whereas Part A would be a low cap allowance, Part B would be a high cap.

We consider there to be substantial advantages to combining options 1 and 2. Based on our experiences of the current demand management innovation allowance (DMIA), option 1 provides a flexible and adaptable funding model for research and development. We have been able to use this funding model to deliver a range of projects from small scale market research through to the testing of more substantial non–network options. The size of the allowance, however, is not sufficient to run large scale trials or explore the commercialisation of demand management opportunities. For these reasons, we consider the Allowance Mechanism the AER designs should include a separate high cap allowance similar to option 2 in the AER's *Consultation Paper*.

The funding of Part A of our preferred Allowance Mechanism should be set at the current DMIA levels, with annual indexation for inflation. For Ausgrid, this would be equal to $1 million per year. By comparison, the annual funding of the high cap, or Part B, component could be set at 0.5 percent of maximum allowed revenue (MAR). This is the same scale of funding that Ofgem allows under its Network Innovation Allowance. In our view, this amount would unlock the potential for electricity distributors to run large scale trials and pursue the commercialisation of demand management projects. While an annual cap of 0.5 percent of MAR is not an insignificant allowance, we consider the requirement for ex–ante approval for each project provides sufficient regulatory oversight given the costs involved.

We consider that refinements could be made to option 1 and 2 before combining them into a single Allowance Mechanism. In our view, the AER should expand the scope of activities that can be funded under option 1 so that electricity distributors are able to pursue a broader range of demand management opportunities. For example, our preference is for option 1 to be broadened to allow for electricity distributors to stage competitive tenders for demand management funding and the recovery of costs associated with stakeholder forums. Such activities would lead to greater co–operation between experts and facilitate knowledge sharing and capacity building.

With respect to option 2, we consider the approval process administered by the AER must be flexible. In its *Consultation Paper* the AER describes a high cap allowance in which distributors put forward projects in their regulatory proposals. We agree that a distributor's regulatory proposal is an appropriate vehicle for the AER and stakeholders to assess the merits of high cap demand management projects. However, due to the dynamic nature of demand management we consider option 2 should be able to respond to project developments and opportunities as and when they arise. Our preference would be for the AER to design an Allowance Mechanism where projects can be proposed in a distributor's regulatory proposal, but with the flexibility for further projects to be approved within a regulatory control period.

## Question 9

## If you have views against applying any of the particular mechanisms in section 7, please provide reasons to support this view.

We have concerns about options 3 and 4 in the AER's *Consultation Paper.* At this stage, we would not support the AER implementing either of them, at least in their current form.

Our concern with option 3 is that it is complex and would be onerous on the AER to administer. We consider there to be merit to having a market mechanism deliver 'ground breaking' research and development (R&D). But agree with the AER's comments in its *Consultation Paper* that a key problem with option 3 is that the 'awarding of R&D will likely require a difficult exercise of discretion as it it difficult to apply objective criteria to R&D proposals'. We also question whether option 3 would fall within the scope of the new rules. Clause 6.6.3(5) provides that 'penalties should not be imposed on distribution network service providers under the scheme'. In our view, a failed bid to recover funding under option 3 is in effect a penalty. This is because every failed bid would be a financial loss taken out of the 0.1 percent of MAR each distributor is required to contribute to the pool of funds allocated to the Allowance Mechanism.

The chief concern we have with option 4 relates to its complexity. Ausgrid accepts that by outsourcing the decision as to who receives funding to electricity distributors the Allowance Mechanism would be relatively simple and administratively straightforward for the AER. Such outsourcing, however, simply shifts the issues associated with option 3 from the AER to distributors. This would lead to a substantial regulatory burden and large transaction costs in the assessment of funding proposals. In addition to this, distributors would also have to deal with the legal and commercial risks associated with cross–funding projects, entering into joint ventures and protecting intellectual property rights. In our view, this makes option 4 overly complex and risky.

We consider a better approach would be to incorporate the intent behind options 3 and 4 in the development of "Part B" of our preferred Allowance Mechanism comprising of a high cap allowance with ex–ante approval. Without being prescriptive, the AER could achieve this outcome by providing increased incentives under a high cap allowance for collaboration or the commercialisation of ground–breaking R&D. For more information about Part B of our preferred Allowance Mechanism refer to question 8 above.

## Question 10

## How might we best give effect to or enhance the information and reporting requirements discussed in section 7.5?

We broadly support the approach to information and reporting requirements outlined in section 7.5 of the AER's *Consultation Paper*.

Ausgrid notes that the AER has suggested a more prescriptive approach. We would support this in so far as it increases clarity regarding our information and reporting requirements, and the level of information that is prescribed is not onerous on distributors.

We encourage the AER to adapt its reporting requirements according to the expenditure that is recovered. While high cap projects may require a certain level of additional oversight, Ausgrid considers the information and reporting requirements for low cap projects should be relatively streamlined.

# Attachment C – Aging asset case study

Over the next five to ten years, most of Ausgrid's forecast network investment will be associated with the retirement of aged assets. This presents limited opportunities for demand management targeted at addressing capacity constraints associated with peak demand.

In this context, we consider that the AER's reforms should consider non–network solutions which, by managing risks associated with equipment failure, defer the retirement or replacement of aged assets. In support of our position, and to demonstrate the challenges distributors face when considering non–network options relating to aging assets, we have included a case study below. This study is illustrative of real challenges Ausgrid is currently facing at aging suburban substations.

## Case study

Our case study involves a zone substation commissioned in the 1960s. It has a peak demand of about 20 MV and both 33kV (circuit breakers and switches) and 11kV equipment (switchgear). As the substation, which supplies around 12,000 predominantly residential customers, is reaching the end of its serviceable life, it has been scheduled for retirement in December 2022.

The advanced age of the substations gives rise to a high risk of equipment failure. In the event of a network element failure, there would be the loss of a significant amount of network capacity which could lead to customer demand outstripping supply.

There are a number of additional factors which increase the challenges associated with managing demand at the substation. In this example, there is not sufficient emergency transfer or system redundancy to restore power to all customers in the event of an equipment failure. This has triggered an investment "need date" based on our analysis of the estimated unserved energy to customers if an element of the asset failed. Repair times for the equipment in question are long (typically in 1 to 3 months).

To address the risk of equipment failure and the associated loss of capacity to meet customer demand, an available network option is to transfer the substation's load to adjacent zones with spare capacity. The total cost of this network solution is $15 million.

Notwithstanding, non–network options may be viable. Such options may include an embedded generator or strategies to reduce customer demand on the affected feeders. In combination with network transfer capacity and other network re-configuration measures, such non–network options might be capable of maintaining supply to customers in the event of an equipment failure.

In this case study, it is notable that we would rely on a non–network solution to a greater extent than when a non–network solution is deployed to address load growth. To support the aging substation, an alternative power supply or demand reduction strategy may be required for a significant number of hours while network repairs are completed. We estimate that the level of network support would be 200–400 hours over the 8–12 week repair period, which greatly exceeds the 40–60 hours per year often associated with load growth. This shows that non–network options employed to defer the retirement or replacement of an asset have a higher potential utilisation than non–network options targeted at avoiding or deferring augmentation. Correspondingly, the unit costs may be higher as well.

## Conclusion

We encourage the AER to incorporate the network investment drivers described in this case study in the design of the Scheme and Allowance Mechanism. This will mean that non–network options that address these important types of network investment are not inadvertently overlooked.

In terms of design elements, we have specific views regarding schemes based on the sharing of net–market benefits. We consider that any metric used to provide incentives under a net–market benefit sharing scheme should include network investments driven by both load growth and the retirement/replacement of aging assets.