19 March 2015

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

By electronic lodgement

Dear Mr Pierce,

ERC0177: CONSULTATION PAPER—NATIONAL ELECTRICITY AMENDMENT (DEMAND MANAGEMENT INCENTIVE SCHEME) RULE 2015

CitiPower and Powercor Australia (**the Businesses**) welcome the opportunity to respond to the Australian Energy Market Commission's (**AEMC**) consultation paper on the Demand Management Incentive Scheme (**DMIS**). In particular, the role of non-network alternatives in the supply of electricity to consumers at low costs is becoming increasing important.

Our submission responds to the questions raised in the AEMC's consultation paper. For example, we support broadening the scope of costs and benefits which can be recovered under the DMIS framework (as it may encourage greater use of demand management solutions). We also support a further review of the approach to innovation adopted by Ofgem in the UK.

To provide greater context, our submission sets out our experience with regard to two demand management solutions we have recently considered implementing. These solutions are discussed in appendix A, and demonstrate the following:

- our experience is that network solutions have typically been less expensive than alternative non-network solutions; and
- non-network alternatives may be less reliable and therefore increase our exposure to STPIS penalties (should the non-network alternative fail to address the network constraint).

In our submission, we have made suggestions on how to address these issues. If you have any queries regarding this submission please do not hesitate to contact Jeff Anderson on (03) 9683 4809, or janderson@powercor.com.au.

Yours sincerely,

Renate Tirpcou

Renate Tirpcou

Manager Regulation, CitiPower and Powercor Australia

Response to questions set out in the AEMC's consultation paper

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?

In our experience, the following factors have limited our ability to implement demand management alternatives:

Scope of the DMIS

As set out in the COAG Energy Council's rule change request, the only benefits distributors are currently able to derive from implementing demand management projects are the cost savings related to deferred or avoided distribution network expenditure.[1] Demand management projects, however, typically also create benefits at other points of the supply chain (such as avoided generation costs and avoided investment in the transmission network). In this context, we support expanding the scope of the DMIS to allow distributors to capture the market benefits.

For example, consider a situation where an investment of $75 million is being contemplated in a particular area of the network, and this proposed investment is a combination of distributed generation (such as rooftop solar generation), battery storage and/or demand replacement. Let this investment be expected to deliver savings of:

- $50 million in the present value of traditional distribution network costs; and
- $50 million in the present value of wholesale market generation.

Clearly, these savings exceed the expected costs of the investment and, consequently, the investment should proceed. However, the investment will not proceed if the investor receives only part (or even all) of just one source of the benefits (i.e. just the wholesale market benefits, or just the network benefits). The $25 million in net benefits from the project will only be realised if the investor can capture some portion of both sources of benefits.

Interaction with other incentive schemes

The costs associated with demand management projects can be broader than just the implementation investment. For example, where a demand management solution fails to address a network constraint, we may incur penalties under the Service Target Performance Incentive Scheme (**STPIS**). In our experience, the parties proposing non-network solutions have not been willing to accept any liability for our exposure to STPIS penalties should their solution fail to address the network constraint. This issue is particularly relevant, as the reliability of non-network solutions are typically lower than network alternatives (e.g. the risk of an embedded generator failing when called upon is greater than the risk of a transformer failing).

[1] COAG Energy Council, *Reform of the Demand Management and Embedded Generation Connection Incentive Scheme, Rule change request*, December 2013, p. 5.

Capped innovation allowance

The AER's current DMIS has two components—a capped demand management innovation allowance (**DMIA**), plus a foregone revenue component. Consistent with our battery storage example in appendix A, we consider the capped DMIA constrains the ability of distributors to invest in innovation. Given the rapid rate of technological change, a well-functioning DMIS should facilitate our ability to respond and realise greater benefits for consumers.

Relative costs of demand management and network solutions

Our experience is that network solutions have typically been less expensive than alternative non-network solutions. For example, as outlined in appendix A, we previously proposed for consideration an investment in a 10MVA gas fired embedded generation unit to relieve network constraints affecting the Geelong East zone substation (**GLE**). This project would likely have delayed the need for a second upgrade to transformer capacity from 2017 to 2025, and depending on the investment, possibly also the first transformer upgrade from 2016 to 2020.

The costs of the GLE generation unit, however, were $3.7 million higher than the network solution.[2] This differential reflects payments for the embedded generator, as well as the additional connection works required to our network to implement this alternative. In many circumstances, including the GLE example, the costs of such connection works are material.

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?**

The limitations of the existing demand management incentive framework are a product of both the Rules and the current design of the AER's scheme. In reviewing these limitations, the AEMC should consider further the approach to innovation adopted by Ofgem in the UK. This approach may provide stronger incentives for innovative non-network alternatives, particularly as businesses approach the efficiency frontier.

Scope of the DMIS

As set out in response to question one, we consider the DMIS should provide greater scope for businesses to recover the benefits from implementing demand management solutions. The rule change proposals by the COAG Energy Council and the Total Environment Centre (**TEC**) acknowledge that this represents a limitation of the Rules framework.

The criteria set out in the AER's existing DMIS may also need to be amended to facilitate the recovery of broader market benefits. For example, the criteria do not appear to contemplate benefits associated with savings in the wholesale generation market.

Interactions with other incentives

In regard to greater consideration of other incentive schemes, particularly the STPIS, the 'gap' appears to be the design of the corresponding incentive schemes. That is, the Rules already require the AER have regard to other incentive schemes in developing and implementing both the DMIS and STPIS.[3] It appears open, therefore, for the AER to consider solutions such as excluding any STPIS penalties that

2 See Table 6 in CitiPower and Powercor Geelong East (GLE) Zone Substation Transformer Upgrades Regulatory Test Report, 12 June 2014, p. 15.

3 See, for example: NER, cl. 6.6.2(b)(3)(iv), (v) and (vii); and NER, cl. 6.6.3(b)(4).

arise where a non-network alternative is being trialled (but eventually proves unsuccessful in addressing the network constraint).

Capped innovation allowance

A limitation of the AER's current DMIS is that the DMIA is capped. We consider the DMIS should enable further funding (beyond the DMIA cap) following pre-approval by the AER. This would facilitate exploration of demand management innovations in a timely manner, and ensure potential efficiency enhancing innovations are not unduly constrained or deferred due to an arbitrary cap.

Relative costs of demand management and network solutions

The competitiveness of non-network solutions reflects the state of the market for such services. For example, the market for services reflects extrinsic factors such as recent increases in gas prices (which have increased costs for gas fired embedded generators), plus declining demand in specific areas of our network (which may reduce the need for demand management solutions).

The regulatory framework—notably, the Regulatory Investment Test for Distribution (**RIT-D**)—may also limit the competitiveness of non-network solutions. For example, as set out in appendix A, it is difficult under the RIT-D to place a value on the options created by the deferral of large investments in traditional 'poles and wires'. The application of the RIT-D, therefore, may lead to investments in innovative solutions being undervalued.

Proposed DMEGCIS

3. In making its decision on the network regulation rule change request, the AEMC considered how much prescription 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 the TEC in their rule change requests appropriate?

In general, we are supportive of a Rules framework that sets out high level objectives, followed by detailed principles that the AER must have regard to in making a regulatory decision (such as determining the construction of a particular incentive scheme). This approach provides the industry with certainty as to the intent of any incentives, as well as flexibility for the AER to amend its approach as the industry evolves.

4. 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?

Notwithstanding the recent changes made by the AEMC, we consider the issues highlighted in response to questions one and two will be important in providing adequate incentives to distributors when considering non-network alternatives.

Demand management innovation allowance

5. 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?

As outlined previously, we are supportive of a Rules framework that sets out high level objectives, followed by detailed principles that the AER must have regard to in making a regulatory decision. This approach provides the industry with certainty as to the intent of any incentives, as well as flexibility for the AER to amend its approach as the industry evolves.

6. 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?

We consider the issues highlighted in response to questions one and two—including increasing the scope of costs and benefits able to be covered by the DMEGCIS—will be important in providing adequate incentives to distributors when considering non-network alternatives. In our experience, (un)certainty in the Rules or DMIS has not been a material factor driving DMIS utilisation.

7. 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)?

We propose the ex-ante capped allowance—Part A of the AER's DMIS—continues to be provided as additional fixed revenue for each year of the regulatory control period. We propose, however, an amendment to the scheme whereby we can seek further funding above the capped amount, on the proviso the AER pre-approves all such DMIS initiatives.

We consider a capped DMIA constrains the ability of distributors to invest in innovation. Given the rapid rate of technological change, a well-functioning DMIS should facilitate our ability to respond and realise greater benefits for consumers.

8. 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?

For the following reasons, we consider the current reporting requirements are sufficient to share the learnings from DMIS projects within the broader industry:

- as acknowledged in the AEMC's consultation paper, distributors are already required to publish details of approved DMIS projects in their Distribution Annual Planning Reports (**DAPR**). The AER has also published its assessment of distributors DMIA expenditure.[4]
- distributors are likely to undertake their own research and/or trials of non-network alternatives, even where published information regarding similar projects exists. This reflects a prudent approach to infrastructure investment, having regard to the variable characteristics of different networks. For example, we expect to roll-out two Rapid Earth Fault Current Limiters (**RECFL**) in our network during the 2016–2020 regulatory control period. The limited roll-out is driven by the need

[4] See, for example: AER, *Decision, 2011–12 and 2012 DMIA assessment*, July 2013.

to develop internal knowledge regarding the functionality and benefits of RECFLs (notwithstanding support for the benefits of RECFLs from other sources, such as research published by the Victorian Government). In this context, it is not clear how additional reporting requirements would outweigh the increased burden.

9. **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?**

Although specific technologies may evolve to a point where they become embedded in business-as-usual practice, new technologies are expected to continually arise. It is not clear, therefore, why the concept of an innovation allowance should be limited to a specific time period.

Demand management incentive scheme

10. **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?**

For the reasons outlined in response to questions one and two, increasing the scope of the DMIS is expected to increase investment by distributors in projects that deliver broader market benefits. A critical issue for further consultation will be how these broader market benefits are calculated.

11. **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?**

The Rules framework should be balanced to provide certainty as to the intent of any incentives, as well as flexibility for the AER to amend its approach as the industry and/or technology evolves (in consultation with industry). In this context, the Rules should be framed to facilitate multiple forms of regulation.

12. **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 purpose of the DMIS, as set out by the COAG Energy Council, is to encourage least cost network investment and operation by allowing access to a proportion of the full benefits delivered by demand management options. Alternatively, the COAG Energy Council stated that the DMIA component is focused on providing a source of funding for the experiment and trial of innovative approaches to demand management and the connection of embedded generators. To the extent that tariff based demand management options can achieve these objectives, it is not clear why they should be explicitly excluded from the DMIS.

For example, tariff based solutions may be used to provide greater signals to customers regarding their electricity usage or investment decisions. However, irrespective of the willingness of customers to respond to these solutions, distributors would be expected to incur costs associated with any trials. These costs may include amending relevant systems, as well as staffing costs associated with engaging with customers in targeted areas. The nature of innovative solutions—notably, that the outcome of any proposed solution may not be clear—provides additional reputational risk to the distributor that is also unfunded.

Appendix A Demand management case studies

This appendix sets out our experience with regard to two key demand management solutions we have recently considered implementing:

- embedded generation in Geelong; and
- battery storage in Ballarat.

Embedded generation in Geelong

In 2014, Powercor proposed for consideration an investment in a 10MVA gas fired embedded generation unit to relieve network constraints affecting the Geelong East zone substation (**GLE**). This project would have likely delayed the need for a second upgrade to transformer capacity from 2017 to 2025, and depending on the investment, possibly also the first transformer upgrade from 2016 to 2020.

This and other investments were assessed in the RIT-D. Of all the investments considered, an investment in embedded generation was estimated to deliver a total present value of market benefits $2.5 million higher than the pure reliance on transformer upgrades ($255.8 million versus $253.3 million). However, because the costs of the embedded generator were $3.7 million higher, total net benefits were $1.2 million lower ($242.6 million versus $243.8 million).[5]

Our experience with GLE is typical of many of the non-network options we have considered. Further, there are reasons to believe that the standard application of the RIT-D may not always lead to the most efficient investment. An important reason is that under the RIT-D it is difficult to place a value on the options created by the deferral of large investments in traditional 'poles and wires'.

As already noted, in the specific context of the GLE, investing in embedded generation was estimated to delay costly upgrades from 2017 to 2025. The benefits of this delay were estimated on the basis that technology would more or less 'stand still' between now and 2025 so that, ultimately, the costly upgrade to the transformers would happen. However, the pace of technological change, including in solar generation and battery storage, is such that there is a non-zero probability that the upgrade of transformers would have been delayed further—or conceivably avoided completely—by new investments in technology available in 2025 but not known at the time of the RIT-D.

That is, investing in embedded generation, by deferring expensive network solutions, creates 'option value' in that it creates the potential to benefit from further technological innovation and change that is likely to occur in the meantime. This might allow the expensive network solution to be:

- further delayed by new investments in (currently) innovative services;
- resized; or
- avoided entirely.

This option value is not generally given any weight in application of the RIT-D and, therefore, investments in innovative solutions to defer investment tend to be undervalued.

---

5 See Table 6 in CitiPower and Powercor Geelong East (GLE) Zone Substation Transformer Upgrades Regulatory Test Report, 12 June 2014, p. 15.

Battery storage in Ballarat

Powercor is currently developing a proposal to invest in a 2MW battery storage (embedded grid scale energy storage system) in the Ballarat area. Powercor has identified grid scale energy storage systems as one of the key technologies that enable the creation of a network for the future. This project would provide grid support services including targeted demand management (capital deferral), two way power flows (improving renewable integration capability and delivering wholesale market benefits), reactive power support and voltage stability support.

This proposed investment is targeted at shifting peak demand on overloaded areas of the network in line with the AER's DMIS funding. The justification for this investment, consistent with the DMIS, is in part to generate actual data and experience from such projects as a stepping stone to considering more widespread use of this technology.

This is in the context of forecasts for storage technologies to significantly reduce in cost over the next 5–10 years, with significantly increased storage penetration into the grid. We want to ensure that we are well placed to respond to such technological change as quickly as possible—the benefits of which would be passed on to users in the form of lower network and/or wholesale energy prices. The proposed trial would allow us to:

- create and optimise safe operational procedures for the control and dispatch of grid energy storage systems on our network;
- trial and assess viability of grid energy storage services including peak demand management and compare the theoretical benefits with the actual benefits realised in the field;
- determine opportunities to streamline costs of deployment and operation of network energy storage for future opportunities and applications;
- capture technical learnings for future opportunities and applications;
- prepare traditional network for mass adoption of energy storage technologies in the near future; and
- utilise energy storage system for network support and peak management at constrained locations within our network.

The battery storage project is being developed in the context of the DMIS. However, the DMIS funding scale is too small to enable us to more widely make use of new services. The project described above would, once completed, account for a significant portion of the funding available to Powercor under the scheme.[6]

[6] Powercor and CitiPower expect to receive $3 million and $1 million respectively for the 2011–2015 regulatory control period. The AER is likely to determine the same approach for the 2016–2020 regulatory control period.