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Australian Energy Market Commission
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Dear Sir/Madam

REVIEW OF DEMAND-SIDE PARTICIPATION IN THE NATIONAL ELECTRICITY MARKET

Thank you for the opportunity to comment on the Australian Energy Market Commission's (**AEMC**) *Stage 2: Issues Paper Review of Demand-Side Participation in the National Electricity Market* (**Issues Paper**).

CitiPower and Powercor Australia (**the businesses**) are distributors operating in the Victorian electricity market that may potentially be impacted by the outcomes arising from the Issues Paper through changes to Chapters 5 or 6 of the *National Electricity Rules*. As a consequence, the businesses consider it important to include its views as part of this current consultation.

This submission addresses the Issues Paper by reference to the aspect of the National Electricity Market (**NEM**) that potentially impact on a distributor (Economic Regulation of Networks, Network Planning and Network Access and Connection Arrangements). The businesses make no comment on matters relating to Wholesale Markets and Financial Contracting or Reliability.

1 General overview

The businesses agree current regulatory arrangements do not sufficiently incentivise the uptake of demand side management alternatives. The present regulatory arrangements, as set in the *National Electricity Rules* and proposed AER guidelines, allow a distributor:

- only a limited period (on average 2.5 years) to retain the benefits of any deferred capital;
- deter research activities and payments to demand side proponents through efficiency carry over penalties; and
- finally, provide no compensation for foregone revenues.

The most efficient and effective way for correcting these incentives should be through an incentive based demand management incentive scheme (**DMIS**). IPART, and now the AER, has attempted to institute an incentive based arrangement in New South Wales through a D factor. Whilst a step in the right direction, the D factor model is complex in nature, creates a lag between expenditure that is incurred and when it is received and is subject to considerable uncertainty with respect to how foregone revenue will be estimated. It also includes onerous reporting requirements and is subject to an ex post evaluation processes which may result in stranding of costs. As a consequence, the D factor is a high cost and extremely discretionary (from a distributor perspective) solution.

What the businesses would like to see developed is an incentive based arrangement, similar to the Victorian Service Incentive Scheme that rewards distributors based on the benefits likely to result from undertaking demand side initiatives. That is, a DMIS should be self funding so that where the costs of undertaking a demand side management initiative are less than the rewards available under the scheme, the distributor will undertake those works. Under such an approach, there would be:

- no need for lodgement of cost/benefit analyses with the AER;
- requirement for negotiation of approvals through the AER; or
- a requirement for ex post assessments of projects.

The benefits of such an approach are increased certainty for all stakeholders, reduced administrative burden on both the AER and distributors and a transparent mechanism for encouraging demand side management initiatives.

2 Economic regulation of networks

1.1.1 The balance of incentives may not encourage the efficient inclusion of demand-side options

Current regulatory arrangements are characterised by two major incentive mechanisms, the efficiency benefit sharing scheme (**EBSS**) and the service incentive scheme (**SIS**).

The current Victorian SIS is relatively high powered. Consequently the penalties associated with unplanned outages are very significant and potentially retained for an extended period of time. Naturally in considering demand side participation (**DSP**) as an alternative to network augmentation, the businesses have sought to ensure any potential liability incurred through the SIS is reflected in its agreements with DSP proponents. Experience to date has been DSP proponents are unwilling to accept liability associated with SIS placing the businesses in the position whereby network augmentation is the only viable alternative.

The EBSS may also act as an impediment to the take up of DSP through the substitution of capital expenditure with operating expenditure. This is particularly so under an EBSS that excludes capital as the incentives to substitute operating costs with capital are relatively strong. The Australian Energy Regulator's *Proposed EBSS Guideline* exempts any payments made to demand side initiatives proponents from the EBSS. The businesses support this decision.

1.1.2 The building blocks control setting method may limit the incentives for innovation on DSP

The businesses agree with the proposition the building blocks control setting method discourages research and development and innovation of any kind, not just DSP.

An unfortunate by product of incentive based regulation is it discourages projects which involve long pay back periods or whose outcome is not guaranteed. Research and development, by its nature, is risky. A ring fenced allowance should be provided for research and development that sits outside the EBSS that is subject to a 'use it or lose it' provision. Additionally the allowance should be subject to an annual reporting allowance describing the activities being undertaken through the allowance.

The benefits of such an approach impose a minimal regulatory burden on the AER and the businesses and secondly, by virtue of the funds being made available upfront, will encourage distributors to undertake the development works rather than be deterred through the administration costs associated with accessing the funds. The reporting arrangement and 'use it or lose it' provisions will provide comfort to customers the funds are not being wasted or being inappropriately retained by the distributor.

1.1.3 The form of price control may not facilitate efficient DSP

In Australia most electricity distributors are subject to a price cap form of price control (revenue yield or tariff basket). The reasoning price caps are preferred can be summarised as follows:

- price caps provide distributors with a strong incentive to develop cost-reflective tariff structures that align prices to their underlying costs;
- the distributor's costs have a greater alignment with output therefore a price cap lowers the risk associated with variations in demand; and
- price caps provide incentives to maximise utilisation of the network, subject to not exceeding capacity constraints.

Cost-reflective tariff structures and maximising network utilisation are entirely consistent with delivering outcomes that are economically efficient and compliant with the *National Electricity Law* objective.

Where DSP delivers a more cost effective solution to a network alternative, it will be equally attractive to a distributor under a price cap form of control as any other alternative form of control. Consequently the businesses do not believe price caps act as a deterrent to the uptake of DSP, particularly when it is coupled with some form of demand management incentive scheme.

1.1.4 The structure and components of tariffs may not provide customers with efficient signals about electricity use

Only under price capping arrangements does the distributor have an incentive to develop cost-reflective tariff structures. Under a revenue cap, a distributor's revenues will be the same irrespective of the tariff structure it adopts; therefore, it does not have an incentive to adopt cost-reflective prices that reflect either the location or capacity based signals discussed by the Issues Paper.

Further, the businesses note the NER provides a number of requirements for distributors to meet when setting tariff structures. Clause 6.18.5(a) of the NER requires tariffs to be set between the stand alone cost of servicing the customer and the avoidable cost of not serving that customer. In addition clause 6.18.5(b)(1) requires consideration of the long run marginal cost for the service.

With respect to location based tariffs, the businesses note that tariffs, at least in Victoria, have predominantly been set on a postage stamp basis. Postage stamp pricing involves a uniform price per unit of capacity used irrespective of location. Postage stamp pricing does provide customers with efficient signals about electricity use. A pure cost reflective pricing approach, which as defined by the NER would reflect the value of assets used to provide the distribution service, would oversignal locational costs. The oversignalling of locational costs would arise because the concept of cost reflective pricing is based on average costs rather than short run marginal cost. Given that the short run marginal cost in providing electricity is typically lower than the average cost, a pure cost reflective pricing methodology would clearly over inflate location based costs.

Postage stamp pricing is also intricately related to Victorian Government social policy objectives regarding regional and rural development. Finally, for the majority of customers postage stamp pricing is administratively simple to implement, low cost to deliver and is consistent with Victorian Government policy with respect to the Grid Equalisation Fund and the write down and write ups of Victorian distributor asset bases.

In terms of capacity charges, demand remains the single greatest driver of network capital expenditure. A decline in energy consumption does not correlate to a reduction in network costs as the distributor is compelled through the SIS and *Victorian Electricity Distribution Code* to have available capacity to meet a customer's demand in the event the DSP is not operating in times of system peak. Such an occurrence is particularly likely under the solar panel example used in the Issues Paper where cloud cover during winter in Southern Victoria often precludes the generation of any energy by solar panels. As a consequence, were the DSP to receive reduced capacity charges, other customers would need to cross subsidise the provision of services to DSP customers.

3 Network planning

As a general point on the matters considered under Network Planning, the businesses believe the AEMC should be cautious that any proposed Rule change does not compromise network reliability and/or security through undue delays as a consequence of extending or increasing the complexity of the processes needed to address network constraints. The businesses would also urge caution with respect to increasing the costs of network planning processes for the sake of DSP proponents, for no consequential benefit to customers.

1.1.5 The Regulatory Test threshold may be limiting the ability for alternatives to smaller network augmentations to be considered

The businesses experience with Regulatory Tests, particularly those under the market benefits limb, has been they create significant delays and expense. The complexities of complying and meeting the processes outlined for Regulatory Tests have typically delayed projects by up to six months and have required the businesses to engage economic and legal consultants to ensure they meet the necessary compliance requirements. Further, once issued, the businesses have not received any proposals from DSP proponents capable of meeting the necessary load or security requirements.

Projects in excess of $10m are uncommon in a distribution context. Consequently to date the Regulatory Test has not created a major burden for the businesses. To extend its application to smaller distribution assets would create the necessity for hundreds of regulatory tests each year and generate significant additional costs for, in many cases, no benefit.

Victorian distributors have a requirement under clause 3.1 of the *Victorian Electricity Distribution Code* (**Code**) to be good asset managers. This includes '*minimising the risks associated with the failure of reduced performance of assets*'. They also have a requirement under clause 3.5 of the Code to produce publicly available annual reports that amongst other things:

- provide an assessment of the magnitude, probability and impact of loss of load for each sub transmission line and zone sub station;
- a description of feasible options for meeting forecast demand including opportunities for embedded generation and demand management;
- where a preferred option for meeting forecast demand has been identified, a reasonably detailed description of that option including estimated costs; and
- the availability of contributions from the distributor to embedded generators or customers to reduce forecast demand and defer or avoid augmentation of the network.

The annual reports must cover both small and large network assets.

The businesses are of the belief the existing Planning Report requirement under the Code provide all the information that is required by a DSP. Further, the information contained in the Planning Report covers a 5 year planning horizon providing more than adequate notice of any network augmentation. In addition, there is nothing preventing a DSP proponent from approaching a distributor at anytime to discuss future plans and request additional information. Consequently the businesses are opposed to an extension of the Regulatory Test to small distribution assets as currently defined.

1.1.6 The planning arrangements may not allow sufficient time for demand-side options to integrate in the planning process

The planning arrangements do provide sufficient time for demand side options to be integrated into the planning process. The businesses point out again that the *Distribution System Planning Report* provides a five year planning horizon, identifies options for alleviating network constraints, provides details and costing of preferred options and is a publicly available document. In the businesses' opinion, five years should be more than sufficient time for any DSP option to be developed.

As discussed previously, Victorian distributors have an obligation under the Code to identify feasible options for meeting forecast demand and provide details and the estimated cost of any preferred option. Given such an obligation, it is incumbent (and prudent) for the businesses to develop network options as soon as they are identified.

A proposal that seeks to constrain the development of network alternatives to the processes of a DSP proponent, who may or may not be able to address the relevant network constraint, will serve to delay the alleviation of constraints and is arguable in conflict with the distributor's obligation to be a good asset manager.

1.1.7 Consultation on augmentation options rather than on the needs of the network may create a bias against demand-side options

Section 3.3.1 infers that identifying network options at the same time as identifying a network constraint creates a bias towards adoption of a network option. It then goes on to contrast how resolution of a similar constraint may occur in a competitive market.

The businesses do not consider the current processes create a bias against DSP. Provision of infrastructure is unlike other commodities in that planning is required well in advance of any constraint arising as a consequence of the long lead times required to implement solutions and the essential nature of the service being provided. Further, regulator's have typically expected distributors, as part of their role as good asset managers, to have asset management plans in place for up to 20 years in advance. The businesses would also argue having a viable network augmentation option serves to provide a counterfactual by which other options can be evaluated.

To prohibiting development of a network alternative until such time as a DSP option materialises (or does not materialise) could again severely compromise network reliability/security and could not be seen as advancing the NEM market objective.

4 Network access and connection arrangements

1.1.8 Arrangements for avoid TUOS and DUOS may under/over value demand management options

Where a demand management option may actually defer spend on the distribution network; there already exist provisions under the Electricity *Industry Guideline No. 15 Connection of Embedded Generation* that define how avoided DUOS should be calculated. The businesses consider these provisions to be fair to both distributor and the demand management proponent and hence should form the basis of any national arrangements.

A more common scenario however in relation to embedded generation is a requirement to spend additional capital. Distribution networks in general are not configured in a manner conducive to the connection of embedded generation and hence require reinforcement of the network. For example, circuit breakers are rarely rated to manage embedded generation resulting in additional risks in terms of health and safety and reliability. It is noted that Ofgem, as part of the fourth United Kingdom Electricity Distribution Price Review, provided funds to distributors to upgrade the network to better manage the connection of demand side initiatives.

1.1.9 Minimum technical standards for connection to the network may provide a barrier to potential embedded generation options

Although unable to comment on arrangements in other jurisdictions, Victorian distributor connection arrangements with DSPs are subject to oversight through the Essential Services Commission. *Electricity Industry Guideline 15 Connection of Embedded Generation* governs the negotiation of connection agreements, charging under connection agreements, calculation of avoided distribution use of system charges and avoided transmission use of system charges. Further, should a DSP feel aggrieved, it has the opportunity to seek a fair and reasonable determination from the Essential Services Commission.

Clause 7 of the *Victorian Electricity Distribution Code* also stipulates the minimum technical requirements for embedded generators connecting to the distribution network. These requirements have been developed by the Essential Services Commission in consultation with DSPs and distributors and represent a compromise in terms of the needs of DSPs and the technical requirements from a distributor's perspective in operating the network in a safe and efficient manner.

The technical requirements of networks and relevant safety legislation are not uniform across Australia. As a consequence, the businesses believe the AEMC must be cautious in any attempt to align requirements across jurisdictions to avoid compromising network security or health and safety. The businesses consider the most prudent approach to any alignment would be to commence with each existing jurisdictional arrangement and transition over time to the extent safety legislation and network security allow.

1.1.10 Deep connection costs to the network may be a barrier to potential embedded generation options

The Issues Paper states that embedded generators should only be required to contribute towards the shallow costs of their connection. The businesses consider such an approach to be inequitable.

Increasingly the businesses are being approached by proponents of relatively large embedded generators seeking connections to the distribution network. Typically such projects trigger deep connection augmentation. Connection of a 100MW wind farm will inevitably involve augmentation of the sub-transmission network and potentially zone sub stations, the costs of which the Issues Paper infers should be paid for by other customers.

The businesses believe in such circumstances where deep augmentation is required, a markets benefits test be applied to determine whether in fact there is benefit to all customers. If it is shown that the benefits do not exceed the costs, the costs of any deep augmentation works should be collected from the embedded generator.

1.1.11 Contracting arrangements for embedded generation may not reflect the network support benefits that can be provided

The businesses believe that in Victoria at least, embedded generators are provided sufficient time and information to negotiate in good faith with distributors. As noted previously, there are numerous codes and guidelines that govern the form of negotiation, technical requirements and the calculation of connection costs. Further, should the embedded generator be dissatisfied with the negotiation, it has the right to seek review through the Essential Services Commission.

Should you have any further questions in relation to this submission, please do not hesitate to contact me on (03) 9683 4465.
Yours sincerely

[signed]

Brent Cleeve
MANAGER PRICE REVIEWS