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Australian Energy Market Commission
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National Electricity Amendment (Local Generation Network Credit) Rule 2015, consultation Paper, 10 December 2015

Jemena Electricity Networks Vic Ltd (**JEN**) welcomes the opportunity to respond to the consultation paper on a rule change request to introduce local generation network credits from distribution networks to embedded generators, which reflects any benefits the generators may provide to the network.

Energy Networks Association (**ENA**) has consulted JEN on the issues presented in the consultation paper and we support ENA's submission on this rule change request.

The AEMC recently considered network pricing under the 2014 'distribution network pricing' rule change and (amongst other things) made rules to ensure network prices better reflect the efficient costs of providing network services to each consumer[1].

The intention of this 'local generation network credit' rule change proposal is to continue this cost reflectivity theme by seeking to ensure that embedded generators receive payment commensurate with the benefit they provide to distribution networks via the deferral of network augmentation.

JEN supports arrangements that promote cost reflective pricing as this ensures that networks face price signals to invest efficiently and that consumers only pay for the level of service they consume.

JEN considers that the rule change proposal raises a number of issues that need to be addressed to achieve true cost reflectivity and long term benefits for consumers, including:

- Identifying the level of firm capacity provided by each embedded generator;
- Establishing where network augmentation has and has not been deferred and for how long—especially given the lumpiness of network investment and the

[1] AEMC, *Rule Determination, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014*, 27 November 2014.

relatively small size of most embedded generators where the average sized solar PV installation is 2.5kW;

- Identifying and excluding the benefit already received by those customers with embedded generation via the existing pricing arrangements in NER 6.18.5 to avoid double counting;

- Determining the administrative costs of calculating the level of credit that best reflects the network benefit of the generation and ensures that there is no perverse outcomes from providing an inaccurate signal (such as over investment in embedded generator).

JEN has supported the AEMC's move toward better reflection of network costs into network tariffs via the 2014 'distribution network pricing' rule change. JEN notes a related issue which the AEMC has recognised in the consultation paper—that is, bi-directional flows and increases in fault levels stemming from embedded generation may result in increased network costs.[2] Any potential rule changes arising from this rule change proposal should consider clause 6.18.4(a)(3) of the NER—which relates to retail customers with micro-generation facilities—and set out AEMC's policy position on reflecting costs and remove any barriers in the NER to achieving that position.

Our detailed responses to the questions posed in the consultation paper are set out in Attachment 1.

If you have questions in relation to the submission, please contact Siva Moorthy on (03) 9173 8774 or at siva.moorthy@jemena.com.au.

Yours sincerely

Eli Grace-Webb
General Manager Regulation (acting)

[2] AEMC, *Consultation Paper, National Electricity Amendment (Local Generation Network Credits) Rule 2015, 10 December 2015*, p 22.

Attachment 1

Questions	JEN responses
Question 1 – Assessment framework 1. Would the proposed framework allow the Commission to appropriately assess whether the rule change request can meet the NEO? 2. What is the relevance, if any, of reliability and security for the purposes of assessing the proposed rule (or a more preferable rule)? 3. What changes, if any, to the proposed assessment framework do you consider appropriate?	1. Yes 2. Embedded generators would be expected to demonstrate that the capacity they provide is "firm" i.e. generation is available when and where it is needed to avoid unplanned outages. This will be an issue for intermittent generation sources (e.g. solar PV) unless they are used in combination with energy storage. 3. No changes required.
Question 2 – Perceived issue with current NER 1. Are the current NER provisions (including changes that have been made but not yet come into effect) likely to provide appropriate price signals for efficient embedded generation? That is, do the NER provide incentives to individually or collectively (including through small generation aggregators) invest in and operate embedded generation assets in a way that will reduce total long-run costs of the electricity system? 2. Do the current NER provisions (including changes that have been made but not yet come into effect) appropriately incentivise network businesses to adopt both network and non-network solutions to achieve efficient investment in, and operation of, the electricity system that minimises long-term costs?	1. Yes, there are a number of mechanisms in the NER which incentivise non-network solutions (e.g. avoided TUOS, network support payments). However the nature of distribution network constraints is such that they are very localised i.e. the embedded generation (**EG**) needs to be located at the point of constraint (or close by) and provide sufficient firm capacity at the time of the constraint (typically late afternoon on JEN's network) in order to defer network augmentations. This means that there are few instances where a clear benefit to the network can be identified. In addition, network businesses are required under the rules (and incentivised by regulatory arrangements) to price cost

Questions	JEN responses
3. If your answer to questions 1 or 2 is 'no', what is the specific area in which the current NER provisions do not achieve these outcomes – for example, is the issue with the current provisions only related to embedded generators of a certain type or below a certain size, or is there an issue for all embedded generators?	reflectively (or transition to such arrangements). This enables pricing arrangements to evolve where small customers can save on their electricity bills when they provide benefits to the network. For example, a maximum demand charge would enable those customers with EG who can reduce their maximum kW level when it matters to the network to save on their network charge. Receiving a credit on top of these savings would over-compensate those customers at the expense of other customers without EG. Such cross-subsidies between customers should be avoided. 2. Yes. As a requirement of NER clause 5.13.1, assessment of non-network solutions is already integrated into JEN's planning processes where: • EG (including solar PV) is incorporated into JEN's top-down forecasting; • Cost benefit-analysis is undertaken of all network and non-network options against value of expected unserved energy; • Non-network options are reported and consulted on publicly for significant network augmentations under RIT-D requirements; and • Demand side engagement strategy and a register of non-network solution providers published on our registers. However, due to the nature of our network (i.e. predominantly an urban network), the nature of the constraints (i.e. localised thermal constraints), and the

Questions	JEN responses
	operating environment (i.e. flat demand growth), no opportunities have yet been identified where EG can cost effectively defer network augmentation. 3. N/A
Question 3 – Determining avoided costs 1. What are the factors that influence the long-run network costs that can be avoided through embedded generation? For example, do these cost savings depend on the location, voltage and type of generation? 2. Can embedded generation materially reduce DNSPs' ongoing operating and maintenance expenditure? If so, to what extent do these cost savings depend on the location, voltage and type of generation?	1. Cost savings for the network would be influenced by: • Location (i.e. Supply impedance, thermal capacity and voltage at connection point); • Nature of existing constraints (e.g. summer peaking, winter peaking, time of day etc.); • Intermittent nature of generation (e.g. solar PV) and whether it can be relied upon to be there at network peak (i.e. firmness); • Size of generation; Energy storage capability; and • Demand forecasts (e.g. flat, decreasing, increasing). 2. EG is unlikely to materially reduced operating / maintenance cost. It is more likely to increase operating expenditure due to: • Generator payments being made; • Voltage regulation / power quality impacts.
Question 4 – Specificity of calculations If LGNCs of some form were to be introduced: 1. What is the appropriate degree of specificity in the calculation of	1. In order to be fair and accurately represent network benefits, calculations would need to consider: • Supply impedance at connection point;

<table>
<tr><th>Questions</th><th>JEN responses</th></tr>
<tr><td>avoided network costs and, if relevant, operating and maintenance costs? For example, should different calculations be made for different voltage levels and/or geographic locations and, if so, what would be the criteria for distinguishing between levels/locations?

2. How often should this calculation be updated, recognising that the potential network cost savings can increase and decrease significantly over time as demand patterns change and network investments are made?</td><td>Thermal capacity of the network assets at the connection point;
Capability of the generator to provide active network support (e.g. voltage control, reactive support etc.)
Existing and forecast constraints;
Demand forecasts; and
Nature of generation (i.e. the level of firmness e.g. intermittent generation is likely to have a lower level of firmness than the nameplate capacity).
2. The calculation would need to be updated at least annually to reflect changes in demand forecasts and plans for network augmentation. Failure to do so may result in poor signals to invest and potentially perverse outcomes.</td></tr>
<tr><td>Question 5 – Potential benefits of the proposal

1. Compared with the current NER provisions, would the proposal:

(a) Provide superior or inferior price signals to embedded generators (including small-scale embedded generators) to incentivise them to invest in and operate those assets efficiently, thereby reducing long-term total system costs?

(b) Provide superior or inferior incentives to DNSPs to adopt efficient network and non-network solutions (including small-scale embedded generation) so as to reduce long-run total system costs?

(c) Have any potential beneficial or detrimental effects on any</td><td>1. JEN does not consider the proposal would better meet the NEO for the reasons set out below:

a. Unless the LGNC accurately reflected the factors detailed above (and does not represent double counting from the cost reflective network prices), then the price signal would be inferior. e.g. it might end up paying generators when there is no augmentation deferral benefit, or increased operational expenditure due to power quality impacts—leading to potentially perverse outcomes .

b. JEN already integrates EG / non-network solutions (of all scales) into planning processes so no benefit would be</td></tr>
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Questions	JEN responses
non-price attributes of the service, such as network reliability and/or security of supply? (d) Reduce or increase the prices consumers pay for electricity? 2. To what extent do your answers to 1(a) to (d) depend on: (a) To whom LGNCs are applied (eg whether it is applied to all embedded generators or whether there are criteria based on a generator's capacity, availability and/or location)? (b) The degree of specificity in the calculation of avoided network costs (ie whether separate calculations are made for different voltage levels and/or locations) and how often it is updated? (c) The proportion of the estimated avoided network costs that are reflected in the LGNCs paid to embedded generators? 3. If you do not consider that the proposed rule would enhance the NEO, are there potential alternative approaches that may do so?	gained in terms of reducing system costs. c. EGs connected to the network via an inverter manufactured to AS4777 standard (e.g. solar PV) has the capability to provide power quality benefits (e.g. voltage regulation) which at present are not factored into price of service. However, providing this capability is not currently a requirement. Therefore, in our experience, it is rarely, if ever, incorporated into the design of small to medium scale EG due to associated increased inverter costs. d. The proposal is unlikely to reduce prices for electricity because LGNC costs will be passed on to consumers. It is more likely to increase costs due to costs associated with administering the LGNC calculation, eligibility and payment systems. Because network investment is lumpy, it is also possible that under the proposal, network businesses would need to make generator payments but still require network augmentation because the full constraint has not been addressed (e.g. can't do half an augmentation or augmentation also required because of age / condition of assets). Where customers with EG already receive a benefit via cost reflective network prices, then the LGNC would result in customers without EG paying for this benefit twice. EG (including solar PV) have been incorporated in our demand forecast as part of the distribution price reset process. Consequently, any costs net of benefits would be passed on to consumers.

Questions	JEN responses
	2. To some degree the answer to question 1 will depend on how accurately the LGNCs reflect the true benefit to the network. To accurately calculate the avoided costs, JEN considers all of the matters 2(a) to (c) as this would require complex analysis and administration. 3. JEN believes that the proposed rule would not enhance the National Electricity Objective (**NEO**) because of the high administrative costs of calculating the value of LGNC attributed to small-to-medium scale EG and the lack of firmness. The current rules require distributors to consider non-network options when dealing with emerging network constraints.[3] Moreover, distributors are required to publish their annual distribution network planning report showing emerging network constraints, which provides ample opportunities for small EGs (whether alone or through small scale EG aggregators) and large EGs to offer network support solutions and be paid for it.
Question 6 – Potential costs of design, implementation and administration 1. What changes would DNSPs and other parties need to make to their existing systems and processes to enable the design, implementation and administration of LGNCs? To what extent does this depend on:	1. JEN considers complex analysis would be required to design a LGNC that accurately reflects network benefit and significant resources would be required for implementation and administration.

[3] NER, clause 5.13.1 (e-j) and Schedule 5.9.

Questions	JEN responses
(a) To whom LGNCs are applied (ie whether it is applied to all embedded generators or whether there are criteria based on a generator's capacity, availability and/or location)? (b) The degree of specificity in the calculation of avoided network costs (and, in turn, LGNCs) – ie whether separate calculations are made for different voltage levels and/or locations? (c) How often the calculation is updated? (d) How often the LGNCs need to be paid? 2. What are the likely costs associated with undertaking the changes described above and how are these likely to vary depending on the factors set out in 1(a) to (d)? 3. How do these costs compare to the expected benefits of the proposed rule change?	(a) The design would have to consider the generator's capacity, availability and location. Otherwise it would not accurately reflect network benefits and may lead to inefficient investment. (b) The calculations of avoided network costs would have to be considered at network level—i.e. low voltage and high voltage network components of the distribution network having regard location as it is a key consideration. (c) We believe the calculations would have to be done on an annual basis. (d) Should the AEMC make a LGNC payment Rule, we strongly suggest the payment must be made via the retailers. Accordingly, payments should be aligned to the network billing frequency – either monthly or quarterly. 2. Network businesses do not currently have billing/payment systems to support direct payments to customers and these would need to be developed (potentially duplicating systems already held by retailers). Additionally, as we have noted our response to Question 1, to design and administer the LGNC would be significant. 3. JEN believes the costs are likely to outweigh any benefits. Of the proposed rule change.