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Dear Hayden,

RE: ERC0191 - Local Generation Network Credit Rule Change

United Energy (UE) welcomes the opportunity to make this submission to the Australian Energy Market Commission's (AEMC) Consultation paper on the Local Generation Network Credits (LGNC) rule change. We also draw your attention to the submission from the Energy Networks Association (ENA) which we support.

UE does not support the proposed rule change to amend the existing NER to enable the implementation of a Local Generation Network Credit. We believe that introduction of the rule change as proposed would increase the costs of providing services to customers without providing benefits, given that

- The mechanism does not provide firm capacity that could be relied on as an alternative to network augmentation
- The proposed payment level at the Long Run Marginal Cost (LRMC) of future capacity would not deliver benefits to all customers
- There are currently multiple mechanisms, both formal and embedded in the incentive mechanisms that address the concerns raised by the rule change proponents and do not impose additional costs on all network users.

Relevance of a LGNC

The proponents of the rule change argue that the LGNC is based on a benefit derived by the DNSP from the operation of independently owned embedded generators (EGs). The benefit, characterised as a "Network Benefit", is defined as significant long-term benefits that EG's provide in terms of deferring or down-sizing network investment or reducing operating costs. That is, predicated on the amount of energy injected into the network by the EGs, this will result in:

- Limited use of network infrastructure and contribute to mitigating peak demand
- Long-run avoided capacity and operational costs of the distribution business in the areas where this peak demand is mitigated

Certainly injection into the network during periods of peak load may have the potential to alleviate the stress networks face as that load approaches capacity. However this contribution to alleviate stress is predicated on the following factors:

- Time of injection: Injection from small scale EG occurs at time when energy is harnessed. This coincides at time when the network is not operating at its peak. Hence the investment on existing infrastructure has already been factored into catering for the network requirements without the need for additional investment to offset the energy transported through the grid.

- Firmness of supply: to meet a DNSP's reliability standards for the effective operation of a network, the EGs will be required to provide the injection into the grid at a time specified by the DNSP.
- Location and amount of energy injected: a location that faces no network constraints due to the adequacy of the existing infrastructure does not benefit from EG.

The concerns in meeting the requirements of the factors stated above are a particular issue for all small scale EGs. However these EGs are already compensated through the following mechanisms:

- Feed in Tariffs: where the EG is rewarded for its injection into the network with regulated rates dependent on the date of uptake of Solar PV system.
- Small Generation Aggregator framework: which allows for a portfolio of EG to be compensated at the market rate. Where a customer has excess consumption that they are able to commit, they may use the small aggregator generator framework to gain the market benefits from selling the excess capacity at the market generation price – we note that very few parties have elected to participate in this framework. Clean Technology partners is an example of one of the providers of this service.

Large EGs also have existing mechanisms in place that cater to and compensate their supply into the network. Additionally this supply meets the criteria for the factors stated above. The mechanisms in place:

- Avoided TUOS charges: Payments can be made to EGs that reflect the cost component that would have been payable to a Transmission Network Service Provider if that (eligible) had not been connected.
- Network support payments: Primarily used as an alternative method to manage network constraint, these payments are negotiated between the EG and DNSP to reflect the economic value the EGs provide.

Large EGs are excluded from UE's forecast demand unless a formalised Network Support Agreement (NSA) is in place to enable a generator to alleviate a network constraint and defer a planned network augmentation. In the absence of a network support agreement, large generators are not considered in the planning process and have no impact on UE's network development plans because they cannot be relied upon to be operating at critical network loading periods. UE does not presently have any NSAs in place with any generators.

Despite the absence of any existing NSAs, there are currently a number of large embedded generating units connected to the UE distribution network. A summary of these generators is provided in UE's Demand Strategy and Plan document, submitted as part of our Regulatory Proposal

The Demand management Incentive Scheme (DMIS) has allowed UE to roll-out demand response solutions in the form of a "Summer Saver Trial" over the past few years in selected areas that compensate the eligible customer for reduced electricity use during times of peak demand. The Summer Saver Trial is a pilot to test the feasibility of UE directly controlling customer load blocks at high demand with this pilot focused on pool pump and air-conditioning control and supply capacity limiting. The customer is then compensated $25 for their reduced use once their usage has been reviewed from the data collected from their installed smart meters.

DMIS has also been effectively used in:

- Doncaster Hill District Energy Services Scheme (DESS): a continuation and expansion of the current project to facilitate implementation phase with non-network solutions to defer augmentations planned for the Doncaster area
- Virtual Power Plant (VPP) Pilot: "behind the meter" solution that focused on 7 constrained distribution substations identified for economic deployment of storage at lower cost than network augmentation – we are now transitioning the VPP Trial from DMIS to BAU

As part of the move to cost reflective network tariffs, UE has submitted a TSS that proposes the transition from energy based tariff to demand tariffs. The introduction of demand tariffs provides incentives for customers to reduce their consumption from the grid at peak times and reduce the cost of network services. While the Victorian Government has proposed restrictions on the transition to cost reflective network tariffs any customer on our network has the opportunity to opt into a demand tariff.

All the mechanisms mentioned above encourage the relevant investment, usage and pricing signals that contribute to the achievement of NEO. This manifests itself in fostering efficient investment in, and use of, embedded generation. On the other hand a payment direct to an EG customer can only result in the customer getting a benefit greater than the benefit they generate at the expense of the rest of the customers of the network.

A LGNC would be relevant if it actually provides the benefit that it proposes. From the points made above the existing framework sufficiently provides for a net benefit that an EG customer is looking to attain.

Feasibility of a LGNC

The LGNC shows itself as a substitution of long-term forecast spend, i.e. deferred or reduced LRMC that would have been incurred to augment and maintain the network. The LGNC is proposed to take the form of a negative network tariff paid to small scale EGs by the DNSP. This "network benefit/value", as defined at the start of the previous section, is complex in its development and application. The three main issues that arise are based on location, type/quality of embedded generator level and the administrative burden of creating such a credit.

In the first instance, a location based formula is quite complex. UE's analysis shows load approaching capacity only in a small number of areas in the network. The areas where investment is required is clearly set out in our DAPR and we invite all stakeholders to make proposals through this and the RiT-D processes. The long-run network cost savings from embedded generation where there is sufficient capacity is zero.

There is only value in an LGNC at the time when the load is approaching capacity. The inaccurate calculation of that forecast avoided cost will lead to inefficient price signals. This goes against the argument that the deferred LRMC for a specific location can be calculated and then translated into a benefit shared across the network.

Proponents argue that a regulator mandated distribution credit will send efficient price signals to EGs. However a shared benefit in the form of a network wide average would lead to inefficient signals as the areas where there is no constraint will be overcompensated for their injection into the network whilst the areas of constraint will be under-compensated.

Voltage levels of the systems also play a part in the overall benefit to the network in that systems with varying capacities and quality may be unduly compensated. If the generation capacity of the EG is either too small or unreliable to have a material effect on projected network cost savings, then there may be no network cost savings at all. That is even if there is a sufficient portfolio of EGs in the location to defer or delay network investment in that area, the pool of generators maybe too small or the source of generation may not be sufficiently reliable when taken as whole.

From an administrative perspective the introduction of a regulated credit mechanism is quite complex. The cost of designing such a mechanism involves the AER's guidelines or multiple guidelines, stakeholders cost of the consultation process and the cost to the DNSP of designing the methodology. The cost of implementation would involve the new systems & process, payment relationships, collection & management of data and the implementation of the regulatory process. Technological advances and the review of input assumptions will affect the calculation and methodologies that this credit will be based on.

Ultimately the net benefits from an LGNC could end being too immaterial or even negative, once the investment costs of managing the flow of the feed in energy and the costs of administrating the credit are taken into account. As the proponents of the rule change argue, the LGNC cannot be negative and therefore a charge to the EG. Hence there is a real possibility that its value will be zero.

Reliability standards required of a DNSP

DNSPs are subject to reliability standards with regard to customer's power supply and the duration of outages. Without a guarantee that the generator will inject a certain amount of electricity at the time of peak demand, the DNSP will still need the capability to transport electricity through the centralised network. As such even when taken as a portfolio, on a location basis, there is no guarantee that the energy fed into the network will cover the load requirement of the area it is being fed into. This requirement of providing electricity as and when required is called firm capacity.

Where there are specific constraints on the network that require investment we contract either directly or through demand aggregators to provide network support services. Additionally we have contracts in place with non-network solution providers who provide demand response solutions through a platform that allows the control of load catered to UE's needs.

A portfolio of local small scale solar EGs cannot therefore provide the network stability required to justify remunerating it for a service. Hence not only will there be no improvement to reliability of areas where local EGs, on their own or as a portfolio exist, there is a real concern that it will lead to decreased reliability.

Perceived benefits

Not all consumers are beneficiaries with the introduction of a LGNC. As the AEMC has pointed out, the LGNC is an effective transfer of wealth from the consultants and engineers to the small scale embedded generators. That is, instead of the DNSP incurring the long run marginal network investment costs, it is now calculated as a network credit to those EG's exporting energy into the network. As the proponents of the rule change argue, the credit is calculated every five years during the regulatory reset and then applied in the tariffs to be recovered from the all the customers on the network.

Hence, the proposal for the rule change as drafted will actually increase cost to the customers by:

- Paying the full value of the future investment, i.e. all customers would pay the same averaged amount and;

- Increase the costs of running and managing the scheme

Ultimately this breaches the key principles of the NEO as there is clearly no net benefit to the customer.

Conclusion

Aside from the points made above, there are additional factors that counter the introduction of a LGNC which include but are not limited to:

- Lack of understanding of full range of costs and benefits from embedded generation across the NEM
- Likely lack of Advanced Interval Metering across the NEM
- Effect of changes in technology relating to network infrastructure, electric appliances and embedded generation itself

These additional factors counter the machinations of a LGNC thereby rendering it administratively burdensome, complicated and archaic in its development and application. Ultimately the introduction of a LGNC can be viewed as a series of payments brought forward and borne by the consumer now - for yet to be determined costs it would incur in the future.

UE looks forward to working with the AEMC and the other stakeholders on this complex rule change process. The consultation timelines and forthcoming workshops present an opportunity to assess the feasibility and risks associated with the introduction of inefficient mechanisms that as stated earlier, do not meet the objectives of the NEO.

If you have any questions on our submission please contact me by email mathew.abraham@ue.com.au or on (03) 8846 9758.

Kind Regards,

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