Attention: Chairperson Australian Energy Market Commission
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Rule Change request from: St Vincent de Paul Society, Victoria - removal clause 6.1.4 in National Energy Rules

The Proposal

The St Vincent de Paul society Victoria is seeking to initiate a rule change to remove impediments in the National Electricity Rules (NER) to Distribution Network Service Providers (DNSPs) recovering costs incurred by the DNSP in supporting the export of electricity from the Distribution Network Users who export energy.

Currently NER 6.1.4 (a) (b) prohibits distribution networks from charging for exports or injections into the grid.

6.1.4 Prohibition of DUOS charges for the export of energy

1. (a) A Distribution Network Service Provider must not charge a Distribution Network User distribution use of system charges for the export of electricity generated by the user into the distribution network.
2. (b) This does not, however, preclude charges for the provision of connection services.

We submit that NER 6.1.4 is in conflict with the network pricing objective in NER 6.18.5(a)

6.18.5 Pricing Principles
Network pricing objective

(a) The network pricing objective is that the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer.

In making this submission we think that for network pricing in the presence of high levels of Distributed Energy Resources to contribute to the promotion of the long-term interests of consumers it is necessary but not sufficient that NER 6.1.4 be deleted.

Back ground

The St Vincent de Paul Society Victoria is of the view that the circumstances in distribution networks are significantly different today than they were when NER 6.1.4 was included in the Rules. When there was very little use of rooftop photovoltaic generation (PV) and government policy was to stimulate the uptake of PV with subsidised feed-in-tariffs there was both no cost to be recovered by DNSPs and DNSP charges would conflict with policy objectives.

This is no longer the case and DNSPs are facing the prospect of additional investment to support the export of electricity by Distribution Network Users. The prohibition on any charge for export also precludes the network for rewarding customers who choose to store energy and export it at a later time.

The National Energy Objective seeks to promote efficient investment in, and operation and use of, energy services for the long-term interests of consumers. Economic efficiency is generally promoted when individuals who incur a cost that is borne by society bear that cost themselves – that is what 'cost reflective pricing' is about.

This paper focuses on what the rules and the network pricing framework should deliver in order to promote consumer outcomes consistent with their long-term interests. SVDP views have been informed by the Distributed Energy Integrated Program access and pricing consultation process and outcome report.[1]

1. Challenges arising from DER

Enabling high DER penetration presents technical challenges as well as additional costs to the energy system. The proliferation of DER is not only an issue for the distribution networks as it also creates challenges for the transmission system and the ability of the market operator to maintain system security.

1.1 Transmission issues

A number of market bodies have been involved in addressing DER challenges for the transmission system, this is a current issue in South Australia and in part a direct result of the increased penetration domestic rood top solar and associated generation.

The Energy Security Board (EBS) has been tasked with working on future market design.[2] The AEMO has developed the Integrated System Plan (ISP) which has

[1] https://arena.gov.au/knowledge-innovation/distributed-energy-integration-program/

[2] See http://www.coagenergycouncil.gov.au/publications/post-2025-market-design-national-electricity-market-nem

"modelled and outlined targeted investment portfolios that can minimise total resource costs, support consumer value, and provide system access to the least-cost supply resources over the next 20 years to facilitate the smooth transition of Australia's evolving power system".[3] The ISP also identifies a number of highly valuable renewable energy zones (REZ) across the NEM, while the AEMC is currently working on the coordination of generation and transmission investment (the COGATI review).[4]

All these workstreams contend with the issue of who pays for what service. A benefit test is being used to model who benefits (e.g. consumers, generators or government) from allowing generators firm access to the transmission system.

As these workstreams address the transitioning of the energy system, similar conversations are needed for the sub-transmission level. In our view, the sub-transmission level is based on a similar framework and the same benefit tests used for firm access to the transmission system may be suitably applied to DER participants and firm access to the distribution network.

1.2 Distribution issues

A high uptake of DER technologies can create voltage issues as well as network congestion. Regulation stipulates that distribution networks must maintain network voltages within a set range as spikes on low voltage lines can damage the network as well as consumers' appliances/equipment.

We have sought information from the network businesses about the magnitude of the problem DER currently presents for network stability and while all those who responded to our request have detected issues, they did not have high quality data that they could share at this point. Furthermore, they all stressed that while DER already are presenting issues for network stability, the focus is on solutions to integrate a greater uptake of DER in the future. As such, the challenge is to ensure that there are efficient network wide solutions to deal with a high uptake of DER.

While there are various ways the network businesses could seek to improve management of voltage issues as well as network congestion, the key issue, from our point of view, is that all remedies will come at an additional cost.

As the cost of DER technologies such as rooftop solar are likely to decrease we can expect to see an increase in uptake, both in terms of the number of installations and the size of the systems installed. We therefore need a to create a framework that can address these issues in the long run.

An increased uptake in DER technologies should be a positive development, however as some consumers will be unable to participate a sustainable framework must ensure that not everyone pays the same when the greatest benefits are returned to some.

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[3] See AEMO, Integrated System Plan, For the National electricity Market (NEM), July 2018, 3 at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf

[4] See https://www.aemc.gov.au/market-reviews-advice/coordination-generation-and-transmission-investment-implementation-access-and

2. Status quo: Inverters tripping and constraining injections

Currently, solar system inverters trip if there are voltage issues. This means that the amount of electricity generated is reduced and that the solar system is delivering below its capacity. Many solar system owners may not register that the inverter has been tripping while others will notice that their electricity generation is reduced as they forego earnings from the feed-in-tariff (FIT) that the exported energy otherwise would have attracted.

Energy networks can also constrain export from solar generation if there is congestion or voltage issues. Most networks do only allow automatic connection of solar systems up to a maximum size (e.g. 10 kW) while systems larger than the maximum threshold will be assessed on a case by case basis to ensure that the local network conditions can incorporate the system. This process is obviously lengthier than an automatic connection and can involve additional costs.

Households in rural areas also typically face more constraints than urban households. In the Essential Network in NSW, for example, there is an automatic connection for rooftop solar systems of up to 5 kW in urban areas while the threshold in rural areas is 3 kW.

The AEMC views export limits as a blunt approach to network issues arising from DER. The AEMC has stated: “Restricting export is unlikely to be efficient or meet consumers’ expectations. Where this restriction applies only to consumers who are connecting to the network at a later time, this raises issues of equity and is likely to be inconsistent with the ‘open access’ nature of the regulatory regime”.[5]

It is clear that the current arrangements are sub-optimal for both DER participants and society more broadly as renewable energy can fail to be harvested despite the investments that have been made. If the level of inverters tripping was to increase, we are also likely to see an increase in complaints to networks and retailers, which again increases the cost of supply to all consumers. Furthermore, there are inequities between urban and rural DER participants.

It has been broadly recognised that there is no “silver bullet” to efficiently integrate a high penetration of DER into the networks and there are likely to be a suite of measures required.[6] A key issue is therefore to ensure that DER participants (and thus direct beneficiaries of DER integration) pay their fair share for the measures implemented.

We realise that there are many low-income consumers that have been, and will continue to be, direct DER participants, and that some will struggle to afford additional

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[5] AEMC, Economic Regulatory Framework Review, Promoting Efficient Investment in the Grid of the Future, July 2018, xi

[6] See, for example, AEMO, Technical integration of Distributed Energy Resources, A report and consultation paper, April 2019, Distributed Energy Integration Program (DEIP), Overview/DEIP at a glance, February 2019, Energy Networks Australia, Embedded Generation Project, Final Report, Marchment Hill Consulting November 2015 and the AEMC’s forward looking work program at https://www.aemc.gov.au/our-work/our-forward-looking-work-program/system-security/lower-emissions

costs. Conversely, there are many low-income consumers that are unable to be direct DER participants, and who are therefore unable to reduce their energy costs or afford additional costs. Just because the additional cost is lower, per household, when smeared across all consumers does not mean it is more equitable, or affordable, than allocating additional costs to those directly participating in, and benefiting from, DER.

3. Current Approaches to network and DER

3.1 Network upgrades

Traditionally Network improvements such as pole and line replacements, network augmentation, including new substations, and 'flexible grid' technology to monitor and control networks in real time have focused on capital expenditure projects.[7] Historically we have seen networks use traditional methods for network management such as building out network to meet changes in consumption patterns. This approach does not necessarily result in the right investment mix. We should seek to learn from the past and enable a framework that delivers the right investment signals to all parties so not only the needs of the network but also the long-term interest of consumers is met at the lowest possible cost. This is particularly important with a fast-changing world were DER are more the normal rather than the exception.

3.2 Connection charges

The Rules currently allow networks to charge a connection charge for solar exporters and this is determined by inverter size. While we recognise that a connection charge can recover costs from active DER participants, it is a blunt instrument. A connection charge does not give DER participants options, or incentives, to change self-consumption, install batteries or engage third parties in managing electricity export. Similar to the traditional fixed supply charge, a connection charge can work as a simple cost recovery tool but it does not provide the price signals required for an efficient DER future.

3.3 Institutional views and processes

The Australian Energy Market Operator (AEMO) published an Integrated System Plan (ISP) for the National Electricity Market (NEM) in July 2018 which noted that it will be important to coordinate DER to capture the benefits it can provide to market and system operations. AEMO stated: "Enabling DER to respond to both market and network signals could also deliver financial savings to consumers".[8] In terms of next steps, AEMO noted that they will continue to "investigate the requirement for increased coordination of DER, the infrastructure to support and integrate those resources, and their impact on the operation and cost of the distribution system."[9]

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[7] See, for example, Powercor's Draft Proposal for the 2021-2025 Regulatory Reset, 18 at https://talkingelectricity.com.au/wp/wp-content/uploads/2019/02/Powercor-Draft-Proposal-2021-2025.pdf
[8] AEMO, Integrated System Plan, For the National Electricity Market (NEM), July 2018, 66 at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/Integrated-System-Plan-2018_final.pdf
[9] Ibid, 99

For the AEMC's 2018 Economic regulatory framework review, the terms of reference directed the AEMC to examine the impact an increasing penetration of DER will have on the economic regulatory framework. The review therefore focused on "the distribution level and considered whether changes are required to the economic regulatory framework to support the continuation of the electricity sector's transformation".[10]

While the AEMC acknowledged that the future model for efficient integration of DER is uncertain, it identified and discussed various *static* and *dynamic* strategies that the distribution networks can utilise to manage an increase in DER penetration.

Static strategies that can be implemented in the short term to address, albeit with limitation, economic and technical issues arising from DER include:

- Cost reflective network tariffs to incentivise consumers to use the network more flexibly
- Using network connection agreements to introduce export limits on solar systems
- Adopting power management strategies (i.e. rebalancing low voltage phase connections and close monitoring of the low voltage network).[11]

Due to the limitations posed by static strategies in the medium to long term, the AEMC is recommending more dynamic strategies be adopted. Initial steps to be adopted by the network businesses include:

- To develop a better understanding of the impact a higher level of DER penetration will have on their networks and the constraints it will place on their low voltage network (e.g. in relation to voltage limits).
- To quantify and publicise the DER hosting capacity of their networks.

It is typically difficult for external parties, consumers as well as regulators, to ascertain the extent of a problem flagged by a distribution business and the solutions that may be required. The network businesses know their networks best, but they may also have an incentive to overestimate problems and/or favour certain solutions over others. As such, we strongly agree that the distribution networks need to closely monitor and publicly report on the impact DER has on the networks.

Furthermore, as the transformation will in all likelihood require network expenditure (whether it is in the form of capex or opex) we believe the time is right to add another aspect to this discussion. Who should pay for the enabling of a higher DER uptake?

4. Proposed Solutions

The below discusses an option that can ensure that DER participants contribute to the expenditure and or be rewarded for services in the short and medium term.

4.1 Allow networks to charge generators for using networks

[10] AEMC, Economic Regulatory Framework Review, Promoting Efficient Investment in the Grid of the Future, July 2018, iv

[11] Ibid, x

This option would require a change to Rule 6.1.4 (a) which currently prohibits networks from charging DER participants Distribution Use of System (DUOS) charges.

> "A Distribution Network Service Provider must not charge a Distribution Network User distribution use of system charges for the export of electricity generated by the user into the distribution network."[12]

The Rule was created with one-way flow of electricity (from generators to consumers) in mind while DER has opened up for a two-way flow. In our view, there is therefore a mismatch between the two-way flow of energy and the one-way charge for using the system.

If the networks were allowed to charge DER participants a charge per kWh for DER exported back via the grid, this revenue could be used to upgrade networks in order to limit constraints and enable future DER penetration.

Importantly, we are not necessarily advocating for an approach where DER participants *have* to pay for using the networks. *Rather we are proposing to explore a solution that allows DER generators / exporters to choose between paying or being constrained.* This is an important distinction as some DER participants may prefer being constrained rather than paying a DUOS charge for export that is consumers have both a passive option the statuesque applies and an active option if they choose to take it up.

For example, if a network experiences congestion on a specific line/substation it can set a DER export price for that specific line/substation. The generating consumer would then determine whether they would a) accept constraints, b) accept the cost of export or c) explore other options such as batteries and coordinated export reductions (including the involvement of 3rd party services).

Naturally, the cost of injecting energy into the network will vary significantly between locations and, in order to enable cost reflective pricing, a nodal DUOS export charge would be required.

The level of constraints differs significantly from sub-station to sub-station. In Victoria's Powercor network, for example, solar is currently constrained almost 20% of the time in Drysdale (the DDL sub-station) near Geelong on the Bellarine Peninsula while it is constrained less than 5% of the time in Corio (the CRO sub-station) east of Geelong.[13] This is not a case of one size fits all and in order to promote cost reflective price signals, nodal pricing for exports would be necessary.

Networks are currently modelling costs and benefits of enabling future solar uptake. Their options, however, are indifferent to individual customer preferences. Rather, the networks are exploring costs and benefits from constraining, network investments and dynamic controls on substation levels.

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[12] National Electricity Rules, 6.1.4 at https://www.aemc.gov.au/sites/default/files/content//NER-v66-Chapter-06.PDF

[13] Powercor, Citipower and United Energy, Placemat, Solar enablement, 7 August 2019

While we acknowledge that networks require, or at least strongly prefer, revenue certainty and that individual customer decisions do not offer the same certainty as regulated cost recovery, the networks can undertake modelling of nodal DUOS charges for export as well as take-up rates in order to project revenue.

As the networks seem prepared to work with individual customers where removing constraints is regarded infeasible (from a cost benefit perspective) by exploring battery storage options, coordinated export reductions and Flexible Grid initiatives, they should also be able to develop and offer individual customers a nodal DUOS export charge.

Furthermore, we believe the market design should encourage and enable energy management services. A high DER future is likely to operate more efficiently if there are opportunities for energy management services to develop solutions that can benefit DER participants as well as the networks. Importantly, a DUOS charge for export will produce a price signal that can incentivise DER participants to engage with such energy management services and be potentially rewarded for their services.

As highlighted in a report by Marchment Hill Consulting for the Energy Networks Australia (ENA), networks can develop partnerships with technology and service providers, as well as retailers, in order to pursue DER opportunities and solutions.[14] The report states:

> "Partnerships will be crucial to ensure that customer are presented with persuasive product offers that promote mutually beneficial EG outcomes. Bundling of product and pricing offers to minimise the impact on customers from the introduction of new tariff structures (e.g. maximum demand tariffs), while at the same time supporting efficient operation of EG to maximise its benefits, will be crucial under a future market state with high levels of EG."[15]

Other parties, such as local governments, may also wish to be involved. Local governments can, for example, offer rate payers storage options in order to avoid these charges. This would complement the policies in place where local governments are pursuing decarbonisation strategies.[16]

5. Broader benefits and challenges

With any change to current framework it is critical that these changes meet the requirement of the National Electricity Objective which is:

[14] The report acknowledges current regulatory and policy barriers that provide a disincentive for networks to pursue this approach.

[15] NSP refers to Network Service Providers and EG refers to Embedded Generation. See Energy Networks Australia, Embedded Generation Project, Final Report, Marchment Hill Consulting November 2015, 235

[16] The Greenhouse Alliances, for example, are formal formal partnerships of local governments driving climate change action across 70 of Victoria's municipalities. See www.victoriangreenhousealliances.org

“to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- price, quality, safety and reliability and security of supply of electricity
- the reliability, safety and security of the national electricity system."

The solutions proposed in this paper are not aimed at penalising households with rooftop solar installed or other Distributed energy resources. We recognise that these households have made investment decisions based on the information (and in some cases, subsidies) made available to them. We are, however, of the view that consecutive governments’ policies promoting the uptake of rooftop solar have created an imbalance in favour of solar and, potentially, at the disadvantage of other technologies, such as storage. If these policies continue, the network problem is likely to exacerbate.

DER is central to a lower emissions energy future and it is therefore imperative that we can achieve a high DER penetration without allowing electricity to become inexpensive for some and unaffordable for others. Inefficient and inequitable allocations of costs and benefits will not deliver the desired outcomes in the long run.

Non-DER participants have already subsidised this initial shift to a DER future and while this has incentivised the DER uptake, largely in the form of rooftop solar, this does not justify ongoing subsidies from non-DER participants to DER participants into the future. Rather, we need to deliver price signals that can incentivise DER participants to engage with energy management services as well as other technologies, such as storage, to deliver a sustainable DER future.

6. Expected impacts

It is believed that the expected impacts of this proposal would result in, but not limited to the following impacts:

- Enhanced opportunities for Distributed energy providers and other participants in this market
- Greater options and choices for Energy consumers and communities
- increased participation of Distributed energy resources in the wholesale and other markets

As the rule change enables options rather than proposed solutions we believe costs will be be minimal.

Recommendation:

We therefore we propose a a rule change to remove impediments in the National Electricity Rules (NER) to Distribution Network Service Providers (DNSPs) recovering costs incurred by the DNSP in supporting the export of electricity from the Distribution Network Users who export energy, which therefore includes the removal of Rule 6.1.4. within the National Electricity Rules.