Genevieve Schulz

Australian Energy Market Commission

Submission made online at www.aemc.gov.au

11 April 2024

Dear Ms Schulz,

Subject: ERC0346 Draft Rule Determination: National Electricity Amendment (Unlocking CER Benefits Through Flexible Trading) Rule

SA Power Networks welcomes the opportunity to provide feedback in response to the AEMC's Draft Determination on AEMO's proposed *Unlocking CER Benefits Through Flexible Trading* rule change.

South Australia leads the world in our uptake of consumer energy resources (CER), with more than 400,000 distributed PV systems and 40,000 residential battery systems. SA Power Networks strongly supports measures to maximise the whole-of-system benefits that CER presents, and our innovative approaches to maximising the distribution network's ability to host CER are regarded as industry-leading, particularly our implementation of dynamic-operating-envelopes (DOEs) for new CER installations*,* Flexible Exports.

Whilst the Draft Determination represents significant progress from the initial consultation and the Directions Paper, there are outstanding issues remaining which have the potential to increase cost and complexity for customers.

Our key points of feedback are as follows, and are further expanded throughout the submission:

1. The cost-benefit analysis (CBA) performed by Energeia is flawed in its assumptions, and significantly *understates the costs* and *overstates the benefits* of the Draft Determination. We propose that the CBA be revised to amend these costs and benefits based on stakeholder feedback prior to progression of the Rule Change.

2. We do not support AEMO's proposed implementation timeframe, requiring all parties to support the Rule Change by May 2026. A significant uplift is needed in metering, market and billing systems for DNSPs, and these changes are not achievable within the proposed timeframe. We propose an alternative implementation target of May 2027, should the Rule Change progress further.

3. We continue to recommend that prior to progression of the Rule Change, small-scale trials are conducted within the regulatory sandboxing framework to better understand the potential issues and volume of customer uptake.

4. Significant issues remain with respect to the implementation of dynamic operating envelopes, static connection limits and demand tariffs for large customers. Integrating flexibly-traded large customers into the distribution network under the proposed model has

the potential to lead to inefficient utilisation of the network, increased costs and complexity for customers, and restriction of future market innovations.

5. We strongly support the introduction of Type 9 metering for assets such as kerbside electric-vehicle (EV) chargers. Lowering the cost to deliver a widespread network of kerbside chargers is a key step towards achieving both State and National decarbonisation goals and ensuring an accessible and reliable charging experience for all EV owners.

6. We support the introduction of Type 9 metering for historically unmetered street furniture and public lighting. However, we do not support the introduction of contestability for the Metering Coordinator (MC) role for Type 9 meters in public lighting where the asset is owned by a DNSP. We feel that restricting DNSP involvement in this role has the potential to lead to safety risks in the management of public lighting, as well as increased costs and complexity for public lighting customers.

We look forward to continuing to engage constructively with the AEMC, AEMO and other stakeholders to support efforts to transition to a more customer-centric electricity system. In the meantime, if the AEMC has any questions on any aspect of our response, please contact Liam Mallamo, Future Networks Engineer, at liam.mallamo@sapowernetworks.com.au.

Jessica Morris

Chief Customer & Strategy Officer

Implementation costs of the rule change

SA Power Networks has significant concerns about the cost implications of the Rule Change as outlined in the Draft Determination and feels that the CBA performed by Energeia materially understates the costs to DNSPs incurred in supporting the Rule Change.

The Energeia CBA assumes that the Rule Change can be supported by DNSPs with no additional investment in market or billing systems, based on the premise that *"networks already have the capability to allocate sub-metering arrangements, such as through controlled load programs."* The arrangements proposed in the Draft Determination differ significantly from those currently implemented for controlled load in our billing system and cannot be supported without a significant uplift.

The data model implemented in our metering, market and billing systems is built around a single NMI per connection point. In order to support customer participation in the Rule Change, this data model will need to be redesigned, and all existing customers migrated across to a new version.

We have estimated that the cost incurred to SA Power Networks in uplifting our metering, market and billing systems to manage multiple NMIs for small and large customers, and multiple FRMPs for large customers is approximately *$28.3M*[1] of expenditure. These costs, and those incurred by other DNSPs, must be accounted for in a revised CBA prior to further progression of the Rule Change.

This estimate is provided under the assumption that only a single additional layer is introduced into the NMI hierarchy, and that customer uptake reaches the levels outlined by Energeia for the rule-change to break even based on the current CBA. We note that a full uplift of our systems to support the Rule Change carries a largely fixed cost regardless of the volume of participating customers. For this reason, we advocate for small-scale trials, conducted under the regulatory sandboxing framework prior to progression of the Rule Change. These trials will provide clarity on customer appetite for participation in the Rule Change and ensure that significant systems changes are not performed for a small volume of customers, incurring high per-customer costs.

SA Power Networks is open to working with the AEMC and Energeia to develop an accurate shared understanding of the uplift required to DNSP systems and processes to implement the Rule Change, as well as the associated costs.

Implementation timing of the rule change

We do not support AEMO's proposed implementation timeframe for the Rule Change of May 2026. This timeframe poses significant risks and challenges for our organisation. We consider that the timelines set by AEMO for procedural changes and detailed design impact the window for DNSPs to implementing required system changes, with AEMO's current timeframes not achievable based on the complexity of required DNSP system changes. The anticipated impact on existing procedures requires thorough review and modification, a process still underway with guidance from AEMO. Extensive changes across our metering, market, and billing systems are foreseen which requires careful consideration and planning to ensure data model integrity and seamless integration for customers.

[1] This estimate is conducted on a $\pm$ 40% basis and is not an exhaustive estimate of all systems changes required to support the Rule Change. It should be taken as an indicative estimate of the most significant changes to our systems required to implement the Rule Change.

Mobilising required resources to implement the systems and process changes as required by the Rule Change is likely to pose a significant challenge, with many of the specialised resources required already forecast to be spread across other aspects of the NEM Reform program implementation and concurrent changes in the regulatory framework for metering services.

We urge the AEMC and AEMO to reassess the proposed implementation timeline, ensuring that all parties can achieve compliance with the Rule Change and propose May 2027 as a more achievable timeline. We note that a May 2027 implementation date will adhere to AEMO's standard release cycle.

Benefits of the rule change – network services

The Energeia CBA modelled a single scenario for small customers where the Rule Change produces net benefits, *VPP Providing Network Services.* This scenario models a customer with bi-directional CER such as a battery participating in a VPP via a retailer, as well as providing network services via a DNSP demand response program.

The Energeia CBA states that:

> *"Network demand management programs for specific devices, while possible under existing arrangements, at the network's discretion may require the installation of an additional standard meter at a premises, such as through a controlled load arrangement."*

The assumption that customers can currently participate in network demand response programs only through the installation of a separate standard meter, or replacement of the existing meter with one containing a controlled load element, is incorrect. There are many examples of DNSP demand response programs implemented *without the use of an additional meter or controlled load.* Examples include SA Power Network's *Diversify* tariff trial, Ausgrid's *Project Edith*, Energy Queensland's *PeakSmart* program and Endeavour Energy's *PowerSavers* program.

SA Power Networks plans to expand our DOE implementation beyond Flexible Exports in our upcoming 2025 – 2030 Regulatory Control Period, introducing bi-directional flexible connections for both small and large customers. This will involve the calculation and dispatch of both flexible export and import limits to participating customers.

Customers who choose to opt-in to a flexible import limit will be rewarded for their participation, and we view this as a network service provided by those customers. We *do not* plan to use any form of additional revenue-grade metering to enable these flexible connections, nor do we plan to use the controlled load elements of existing meters. *Site-level* response, metered at the network connection point using the primary meter, is the only datapoint we require for 'settlement' of customer response to a network signal.

In addition to an expanded DOE implementation, we also plan to trial the use of a network services marketplace, procuring services such as reactive power support from VPPs and customer assets. We feel that this can be accomplished without the use of additional metering, and again plan to only use site-level response from the primary meter to settle response in this marketplace.

We strongly recommend that the revised CBA *remove* the costs involved with, and hence benefits of avoiding, additional metering under the current *VPP Providing Network Services* scenario.

Benefits of the rule change – network visibility

Energeia highlights increased network visibility as another key benefit stream arising from the Rule Change, through the availability of device-level metering data to DNSPs from participating customers. This is assumed to provide a level of visibility to sites that do not currently have a smart meter, as well as increased visibility to sites with a smart meter already present.

Whilst we support the provision of interval energy data to DNSPs from Type 8 and 9 meters upon request, we note that the provision of power-quality data is subject to the *Accelerating smart meter deployment* rule change. Power-quality data provides the majority of benefits with respect to network visibility, and we strongly believe that DNSP access to this data should be made mandatory via the corresponding rule change.

We foresee three potential scenarios with respect to smart metering arrangements for customers participating in Flexible Trading Arrangements (FTAs), each with varying levels of benefit provided to the network through increased visibility:

1. Customer has an existing smart meter, from which the DNSP is currently procuring power-quality data;
2. Customer has an existing smart meter, from which the DNSP is *not* currently procuring power-quality data;
3. Customer does not currently have a smart meter.

In situation 1, the marginal increase in visibility provided to a DNSP via device-level visibility does not provide material benefits to network utilisation or reduction of potential augmentation to integrate future CER when compared to site-level visibility. Whilst we envision use cases for device-level metering data in network forecasting, modelling and optimisation, these datasets are widely available through existing research projects and public data repositories. We do not see significant additional value in our network models using bespoke per-device metering profiles derived from customers participating in FTAs.

In situation 2, we do see potential benefit from customers with an existing smart meter that the DNSP *has not procured power-quality data from* opting into FTAs, which will give us a level of visibility over a site that previously had none. This benefit is only available if the Rule Change ensures that DNSPs can access *power-quality* data from Type 8 and Type 9 meters *at no direct cost*. It should also be noted that this benefit is only available until such time that the *Accelerating smart meter deployment* rule change comes into effect, at which point the now marginal increase in visibility provides minimal benefit, as outlined for situation 1.

For situation 3, we feel that participation in the Rule Change is unlikely to be possible without a Type 1 – 4 meter as the primary meter, in order to implement the proposed subtractive metering arrangement. This negates the potential of the Rule Change providing visibility to the DNSP over sites without a smart meter.

We suggest that the benefits of network visibility be re-assessed on this basis and included in a revised CBA prior to further progression of the Rule Change.

Network connection limits and Dynamic Operating Envelopes

The Draft Determination represents significant progress from the Directions Paper with respect to the impact of the rule change on network connection limits for small customers, through the removal of multiple FRMPs at these sites. SA Power Networks does not foresee any negative impacts from the Draft Determination on the application of network connection limits for *small* customers, but we do see significant issues with *large* customers operating under multiple FRMPs. These issues are not limited to DOE implementation but are present regardless of whether a large customer is operating under a static or dynamic connection agreement.

With respect to the impact of the rule change on DOEs, the Draft Determination states:

> *The Commission considers that, where DOEs are issued to customers, compliance with DOEs could be managed through contracts between the customer and the network, potentially supported by contracts between the customer and its FRMPs (i.e. contracts would include the DOE and specify arrangements to ensure it is not breached, or consequences if it is).*

Network connection limits, whether static or dynamic, are calculated based on the technical limits of the network, ensuring that the thermal ratings of our assets are not exceeded and that the voltage at a customer connection point remains within statutory limits. Non-compliance to a connection limit can causes serious issues on the network, including loss of supply and disconnection of generation. We feel that relying on contractual arrangements to manage compliance to connection limits between multiple FRMPs increases the risk of non-compliance and introduces additional risk to the network.

This risk stems from the practical complexity of distributing site-level capacity limits between multiple parties, each of whom may be competing to maximise their access to said capacity. We see three potential options to mediate site capacity between multiple FRMPs operating at a large customer site:

1. **Primary FRMP as site mediator**
   DNSPs allocate *site-level* available import or export capacity, to a 'master' device such as an Energy Management System (EMS), at the connection point and maintained by the primary FRMP. The EMS has visibility and control over each device and mediates site capacity amongst all 'slave' devices operated by secondary FRMPs.

2. **First come, first served**
   DNSPs allocate *site-level* available import or export capacity to each NMI. Under this model, each NMI receives the same capacity (calculated for the entire site). Each FRMP must maintain monitoring of the net site load at the connection point, and each attempts to optimise their own operations whilst ensuring that the site level limit is maintained. This results in a 'first come, first served' approach as each FRMP attempts to operate their asset.

3. **DNSP as site mediator**
   DNSPs allocate *NMI-level* available import or export capacity to each NMI. Under this model, each NMI receives a unique connection limit. Each FRMP can operate their asset independently, ensuring that the output remains below the assigned NMI connection limit.

Option 1 minimises the risk of site non-compliance to a network connection limit but requires the presence of an EMS and introduces significant technical and commercial complexity for the customer.

A large customer operating with two or more FRMPs onsite who are market participants or followers will require:

- Technical integrations between the EMS and the market control systems of all FRMPs;
- Technical integrations between each controlled asset and the EMS itself;
- Agreements between all FRMPs to ensure capacity is fairly and reliably divided between multiple controlled assets

We note that whilst this option provides the best results from a network perspective, by allowing DNSPs to maximise network capacity allocated via connection limits and minimising the risk of non-compliance to those limits, it introduces major upfront barriers to customers operating under this model, with the technology and vendor offers required to enable this model in a nascent state.

Option 2 relies on ungoverned interactions between the FRMPs onsite and introduces the most risk of non-compliance to network connection limits. To manage this network risk, the DNSP response may be in the form of more conservative, probabilistic connection limits, leading to inefficient utilisation of the network and a loss of market benefits from CER exports.

This model also contains the same risk outlined in Option 1, where FRMPs do not have certainty of the site capacity they can utilise, and hence cannot provide certainty of their market response when forming bids.

Option 3 maximises the certainty of available capacity for each FRMP and minimises the risks of non-compliance to network connection limits. In the absence of network visibility over the short-term operational forecasts of each FRMP, however, the limits assigned to each FRMP will result in an underutilisation of the customer's assets. DNSPs will not be able to 'dynamically' allocate capacity between the FRMPs, and hence will allocate the same capacity to each FRMP regardless of their intent to use it. This results in a loss of potential market capacity from that site, and limits the ability of each FRMP to optimise their operations.

SA Power Networks holds that implementing a multiple FRMP arrangement on large customer premise under the current nascent technological landscape of behind-the-meter energy management has the potential to lead to:

- Increased cost, complexity and uncertainty for customers, retailers and aggregators, and
- Restriction of market participation of flexibly traded assets, or
- Inefficient utilisation of the distribution network.

For these reasons, we recommend the AEMC consider the cost, complexity and network utilisation impacts of these options in a revised CBA. Furthermore, if the Rule Change is to proceed, we recommend that further consultation with industry is undertaken to determine whether greater guidance and protections on network capacity allocation under the Rule Change is needed to ensure that:

- Fair and equitable network access is made available for all FRMPs to ensure they can efficiently provide the services the Rule Change is intending to enable, and;
- Network capacity limits are maintained such that reliability and power quality is preserved for all customers.

Public Lighting

We support the introduction of Type 9 metering for street furniture and public lighting. We see benefits for public lighting customers transitioning from historically unmetered assets to the new metering arrangements, allowing for more cost-reflective pricing and ultimately reducing costs for all customers.

Metering Coordinator Role

We have significant concerns around the proposed contestability arrangements, however. We do not support the introduction of contestability for the Metering Coordinator (MC) role for Type 9 meters installed in DNSP-owned public lighting, under the assumption that the installation of smart photo-electric cells with in-built metering installed in public lighting can only be performed by the MC under the Rule Change. We would welcome clarification from the AEMC and AEMO on this assumption.

The majority of public lighting assets in South Australia are owned and managed by SA Power Networks, including full responsibility in meeting service standards. Ensuring safe access to our assets will potentially require multiple site-visits from the DNSP to facilitate installation and operations under the MC role being performed by a third-party, introducing additional cost and complexity into the metering process for these assets.

The provision of the MC role by a third-party for street furniture and public lighting is unlikely to result in an attractive business case for traditional metering service providers. The Draft Determination suggests that *"DNSPs could offer this service through their ring-fenced contestable service provider."* For our unregulated entity, Enerven, to perform this role it would require significant system duplications. Economically and practically the roles of Metering Provider, MC and Metering Data Provider could only be performed by entities already performing that function.

Given the uncertainty of third-party willingness to adopt the MC role for DNSP owned public lighting, and the complexities involved in managing safety risks for third-party access, we see a need for the DNSP to be able to act in this role. The Draft Determination notes that *"Where DNSPs wish to serve in the role of MC for type 9 metering installations (notably street lights) the Commission is advised that DNSPs can apply to the AER for a ring-fencing exemption."* SA Power Networks sees the application for a ring-fencing waiver as a necessity in these instances and suggests that streamlined waiver processes may be required with the AER to ensure that the MC role for public lighting and street furniture can be fulfilled.

DNSP visibility over aggregated assets under a Type 9 metering arrangement

SA Power Networks supports the proposal to allow the aggregation of multiple public lighting or street furniture assets under a single Type 9 NMI. We note that this has the potential to introduce safety and operational risks to DNSPs however, due to the reduction in visibility over the location of individual network connection points. Public lighting assets currently operating under an unmetered, Type 7 arrangement have their location individually visible to DNSPs through separate asset management systems. We see a risk in our ability to safely manage the network without geographic visibility of every discrete asset connected to our network, including for emergency response, public asset location services and connection/abolishment.

We propose that DNSPs be provided geographic visibility of each distributed device aggregated under a single NMI and Type 9 meter, namely for public lighting and street furniture, including kerbside EV chargers, telecommunication cabinets and phone boxes as an example. We do not propose a requirement for this arrangement at single large customer premises. This visibility could potentially be provided via DNSP visibility over the CMS managing these distributed assets, but we note that visibility should be provided in a standardised manner between DNSPs and all parent NMIs serving aggregated, distributed assets.

Network Tariff Implications

Large customers in South Australia with a demand of above 120kVA are required to operate under a demand tariff. This arrangement reflects the impact on the network of the customer's load and provides a meaningful price signal to incentivise efficient use of the network and recover the costs of augmentation where required.

The introduction of multiple FRMPs on a large customer premises introduces additional complexities for customers on demand tariffs. With the network tariff levied at the primary FRMP, control of an on-site asset by a secondary FRMP has the potential to create financial penalties for the primary FRMP, despite the asset being out of their control. Of primary concern is a secondary FRMP operating their asset in such a way that the site demand breaches the 120kVA threshold, and the primary FRMP is then moved onto a network demand tariff, increasing the cost to serve all load on the connection, whether flexible or not.

The Draft Determination advises that these impacts can be managed by the "*customer and the primary and secondary FRMPs through their contractual arrangements."* Whilst we agree that these issues can be mitigated on an individual basis between FRMPs, we feel that consumer protections should be considered to manage the potential increased cost and complexity for customers in these situations.

We also note that The Draft Determination suggests the potential of DNSPs offering unique tariffs to each FRMP on a customer site, as *"DNSPs have flexibility under the NER to develop targeted tariffs, including at secondary points."* We support the Commission's decision to not include a requirement for this in the Rule Change and we do not see it being a prudent solution in future. Our demand tariff threshold of 120kVA is designed such that sites operating below that limit can typically be integrated onto an existing low-voltage transformer, whilst sites above that threshold will typically need network augmentation to support their increased demand. Offering demand tariffs only to a portion of a site's load mitigates the benefits of this cost-reflective pricing model and is unlikely to drive efficient use of the network.

Beyond demand tariffs, SA Power Networks does not see merit in networks developing and applying bespoke tariffs to flexibly traded CER. We do not support technology-specific tariffs as they are inconsistent with the *National Electricity Rules Network Pricing Objective*, and as such, we would be unlikely to assign different tariffs to secondary NMIs, instead preferring to maintain the DNSP to site relationship via the primary NMI under a single tariff.

Type 8 and Type 9 Metering Arrangements

Kerbside EV Charging

SA Power Networks strongly supports the introduction of Type 9 metering for minor-energy flow assets such as kerbside electric vehicle (EV) chargers. We are actively developing a rollout strategy for a network of kerbside EV chargers in South Australia and see the proposed metering framework as a significant opportunity in the development of such a network.

The ability to leverage in-built measurement capabilities of EV chargers will lead to a material reduction in the cost to deploy kerbside EV chargers, as well as simplification of the installation and maintenance requirements.

We do note that the ultimate benefits of this arrangement are subject to AEMO's yet-to-be-determined metrology requirements, and we advocate for industry consultation during the development of the Type 9 metering specification in order to maximise the benefits to all parties that the Rule Change offers.

Type 9 as primary meter for single large customers

SA Power Networks supports the introduction of Type 8 and Type 9 metering arrangements, but we do not support, either of these metering types being used as the *primary* meter at the connection point of a single customer, whether residential or commercial, except for street furniture or public lighting. We note that this arrangement is not proposed for Type 8 meters, which we support, but the Rule Change does propose that Type 9 meters can be used as the primary meter at the connection point of a single large customer.

A seemingly minor reduction in metering accuracy can lead to significant volumetric change for single large customers. Type 9 metering arrangements would need to be at least as accurate as the current Type 1- 4 specifications, in order to prevent an objective reduction in metering accuracy for large customers. We see a requirement for this level of accuracy in Type 9 meters as potentially requiring significant uplifts in the in-built metering capability, and hence costs of CER, negating the benefits of utilising that in-built metering.

SA Power Networks proposes that the use of Type 8 or 9 meters at small or large customer premises respectively, with the exception of street furniture and public lighting, should only be possible when coupled with a Type 1 – 4 meter as the primary meter at the connection point, in order to implement the proposed subtractive metering arrangements and ensure that site-level metering and billing retains current levels of accuracy. Customers with an existing Type 5 or 6 accumulation meter will need to first replace the primary meter with a Type 1 – 4 meter before implementing Type 8 or 9 child metering arrangements at the premises.

Minimum consumption threshold for Type 9 meters used for public lighting and street furniture

The Rule Change proposes that Type 9 meters can be used at the primary connection point of large customers, defined under the National Electricity Retail Law (NERL) as a customer consuming more than 100MWh per annum. As previously stated, whilst we do not support the use of a Type 9 meter at the primary connection point of a *single large customer*, we do support the use of Type 9 metering for street furniture and public lighting, including kerbside EV chargers.

SA Power Networks is concerned that the potential restriction of Type 9 metering to 'large customers' as defined in the NERL implies that a 100MWh minimum consumption threshold for *all* Type 9 metering applications will be applied, including public lighting and street furniture. Such a threshold would restrict the ability for public lighting and street furniture, including kerbside EV chargers, to operate under Type 9 metering arrangements, as these assets will not meet this threshold, whether singular or aggregated.

We strongly recommend that no minimum consumption threshold is applied for Type 9 meters used for public lighting and street furniture, including kerbside EV chargers.

Customer Visibility of Type 8 and Type 9 Metering

SA Power Networks wishes to seek further clarification from the AEMC on how the Rule Change may impact AEMO's Metering Data Provision Procedures, specifically whether there would be a requirement for DNSP's to provide customers with visibility of their meter data at the secondary settlement point for Type 1-4, Type 8 and Type 9. This would further increase our system costs if required, as meter data would have to be brought in and exposed in our customer-facing systems. We note that most assets implementing a Type 8 or 9 meter would already have some level of customer access to data from the device, potentially negating the need for DNSPs to provide customer access to data from these meters.