Julia Cassuben
Australian Energy Market Commission

Submission made online at www.aemc.gov.au

Dear Julia,

ERC0378 AEMC Draft Determination – Accelerating smart meter deployment

SA Power Networks welcomes the opportunity to provide feedback in response to the AEMC's Draft Determination.

As a Rule proponent, SA Power Networks supports the Draft Determination to accelerate the universal deployment of smart meters to all customers by 30 June 2030. The accelerated transition to smart meters is a key step in the National Energy Market (NEM) reform to support the cost-effective decarbonisation of the energy market. Smart meters provide customers greater visibility and control of their electricity consumption and associated costs, with access to innovative products and services, and will help to support better integration of Customer Energy Resources (CER) in the future. In addition, the increased data available from smart meters will enable Distributor Network Service Providers (DNSPs) to better manage their networks, reducing network costs, minimising networks safety risks and boosting CER hosting capacity.

The joint[1] Rule Change request that adopted the rules as proposed by the AEMC in its Review of the regulatory framework for metering services, highlighted that each party *"may have different views on detailed rule drafting matters as the rule change progresses and will each make individual submissions to later stages of the rule change process"*[2].

Noting this, we have some concerns with the Draft Determination and seek to have these addressed in the Final Rules to ensure effective operation of the NEM and maximise benefits to customers. These include:

- The definition of power quality data and availability from all customers -direction of the power flow and its availability from all customers are critical to maximise the number of use cases for the benefit of all customers;
- Penalty provisions associated with shared fuse outages - applying strict timeframes to smart meter replacement at shared fuse sites where it is part of the Legacy Meter Replacement Plan (LMRP) does not warrant being a Level 2 civil penalty provision, as it is not critical to the achievement of the smart meter rollout;
- The commencement date of one Rule - the commencement date for the shared fusing replacement procedure should be 1 July 2025;

1 The joint rule change request was initiated by Intellihub, SA Power Networks and AlintaEnergy.
2 Joint rule change request page 2.

- The obligation to manage metering installations beyond 2030 - the exemption for testing and inspection requirements for legacy meters should remain in place for the remaining legacy meters until they are replaced by a smart meter; and
- Legacy Meter Replacement Plans – some of the proposed rules require clarification.

We provide further detail on each of these areas of concern in Attachment 1.

If you wish any further information or clarification on our submission, please contact Mr Grant Cox grant.cox@sapowernetworks.com.au or 0403 582 024.

Yours sincerely,

Sophie McRae
Acting Chief Customer and Strategy Officer

Attachment 1

Power Quality Data

SA Power Networks strongly supports the AEMC's Draft Decision to provide DNSPs with power quality data (PQD), like metering data, at no direct cost. We agree with the AEMC's Review of the regulatory framework for metering services, Final report, 30 August 2023 that the universal provision of basic PQD will support efficiency and certainty of access to data that is crucial for several uses, such as:

- **Improving customer safety outcomes** – by enabling DNSPs to detect neutral integrity faults and voltage excursions at the customer premises earlier, so they can be addressed before they pose safety risks to customers.
- **Supporting CER integration** – by enabling greater visibility of the Low Voltage (LV) network. This will support initiatives such as Dynamic Operating Envelopes (DOEs) to allow more customer CER to connect and export without unnecessary constraints or investments.

SA Power Networks has two concerns with the Draft Determination, firstly relating to the definition of PQD and secondly that the provision of PQD is limited to small customers (ie 160MWh per annum in SA).

The Draft Determination defines power quality data as:

"The characteristics of the power supply as measured by the meter, which includes measurements of voltage (in volts), current (in amperes), and ***power factor*** *(expressed as the ratio of the active power kW to the apparent power kVA or as a phase angle)"*

The Joint proponent rule change submission proposed that *"This definition would include reference to the data points that comprise Power Quality Data, which at a basic level includes voltage, current, and active and reactive power (which could be represented as a phase angle)"*. We note the AEMC's working group on PQD recommended voltage, current and phase angle (for active and apparent power).

Our concern is that power factor does provide the direction of the power flow (ie export or import). The direction of power flow is critical to show the behaviour of a site. Having this visibility allows DNSPs to enable a number of use cases, including being able to accurately determine the network's hosting capacity, rather than relying on estimates. SA Power Networks uses this hosting capacity to make available more export capacity to Flexible Exports customers. The direction of power flow also allows DNSPs to determine a site's compliance to CER standards, which is a focus of AEMO[3] to ensure that system security risks are mitigated.

If the AEMC desires to limit the number of PQD fields delivered to DNSPs to three, it could either specify:

- Voltage, active power, and reactive power[4] (as current can be calculated from these fields); or
- Voltage, current, and phase angle (phase angle is the number of electrical degrees of lag or lead between the voltage and current waveforms in an ac circuit).

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3 See AEMO Report Compliance of Distributed Energy Resources with Technical Settings: Update https://aemo.com.au/-/media/files/initiatives/der/2023/oem_compliance_report_2023.pdf?la=en&hash=E6BEA93263DE58C64FCC957405808CA6

4 It is SA Power Networks understanding that apparent power is the combination of real and reactive power, and consequently the PQD should be specified as real and reactive power.

We recommend the PQD definition be amended to:

"The characteristics of the power supply as measured by the meter, which includes measurements of voltage (in volts), current (in amperes), and ***phase angle*** *(or active and reactive power))"*

The second area of concern is that the PQD provision will be limited to small customers (ie 160MWh per annum in SA). The Review of the Metering Framework determined that the most beneficial outcome for customers was for PQD to be made available from all customers, where the metering installation could provide that information. We consider that PQD should be treated like metering data and be provided for all customers, and not just limited to small customers. Some large customers (ie in SA > 160kWh per annum) are connected to our low voltage network and consequently would benefit from the neutral fault integrity assessment. Expanding the PQD provision to all customers, including large customers would enable the maximisation of the benefits of CER to them and the wider customer base.

Therefore, we propose the clause 7.10.3(a1) be modified to:

(a1) The *Metering Data Provider* must provide *power quality data* from ~~*small*~~ *customer metering installations* to the persons referred to in clause 7.15.5(c2) as required by and in accordance with the *Rules* and procedures authorised by *AEMO* under this Chapter 7.

We consider that the processes for provision and validation of PQD should be contained within the AEMO process, rather than embedded within the Rules.

To support the PQD delivery date of 26 June 2025, and allow the scalability for Advanced PQD, SAPN encourages a PQD delivery mechanism which is not bundled with customer billing data. SAPN will also support a transitional arrangement to assist with metering providers meeting the start date.

Timeframes for addressing shared fuse sites

SA Power Networks does not support the AEMC's proposal to make DNSPs' compliance with shared fuse outage timeframes (clause 7.8.10D) a Tier 2 civil penalty provision as this will lead to poor customer experience in some instances. Some flexibility is required to enable a DSNP to manage its workload to provide the best outcomes for its customers, including during times of significant network outages.

We note one of the key objectives of the Legacy Meter Replacement Plan (LMRP) is the replacement of all Legacy Meters with smart meters in a timely, cost effective, fair and safe way during the LMRP Period. We consider that application of the strict timeframes in the shared fusing meter replacement procedure (see propose clause 7.8.10D) are not required to achieve this LMRP objective.

We assume, like SA Power Networks, most DNSPs are unaware of where all shared fuse sites exist. We do not have adequate data to identify if a metering installation is part of a shared fuse installation, making it difficult for us to adequately plan this work in advance. While SA Power Networks will undertake best endeavours to schedule adequate resources to complete this work within the required timeframes, we acknowledge this lack of data is likely to lead to peaks and troughs in the number of share fuse site requiring action at any point in time. When peaks in the number of sites occur, it is likely that adherence to the strict timeframes will lead to resource challenges for all parties involved and potential for greater customer disruption and inefficiencies in replacing the legacy meters. In some cases, due to the number of legacy meters present at a share fuse site, it may require several outages on different dates to replace all the legacy meters. It is normal practice for SA Power Networks to not interrupt customers on consecutive days, with outages staggered by about a week to minimise the customer inconvenience. Therefore, we consider it important that the timeframes for shared fuse outages, when they are identified in conjunction with the LRMP, have some flexibility to cater for peaks in workload and to minimise customer inconvenience.

We consider that clause 7.8.10D(c) should be amended to not mandate a site visit by the DNSP after being notified by the retailer. There may be cases where a site visit is not required (eg where the share fuse only supplied a few customers). Mandating a site visit could introduce additional costs in the shared fuse rollout. The Rules should mandate an assessment by the DNSP, which may require a site visit.

We consider the obligation should be of a best endeavours nature or alternatively completion of a percentage (eg 90%) within the specified timeframes. Strict timeframes continue to be appropriate where there is malfunction of a legacy meter in a shared fuse site.

We also believe that improvements could be made to clause 7.8.10D(e) that would require each retailer to not only appoint the Metering Coordinator within 10 business days of the Shared Fuse Meter Replacement Notice from the LNSP, but to also raise the relevant "Market Service Order Transactions" within 15 business days of receiving this notice. These transactions are key parts of the process developed by industry to ensure a successful "one in all in" process.

There may be situations where a retailer considers that they are not required to replace a legacy meter in a shared fuse site, for example where they are the FRMP for a disconnected NMI or they do not have an active customer. The AEMC should make it clear in these situations if the retailer is required to replace the legacy meter with a smart meter during the "one in all in" outage or if this can be completed at a later stage (which would require a further outage to be arranged).

Commencement dates of draft rules – specifically the shared fuse procedure

To provide sufficient time for process and IT system changes, SA Power Networks strongly recommends updating the effective start date of the new obligation related to the 'one-in-all-in' meter installation process to 1 July 2025.

Business to Business (B2B) Procedures required to implement this process will not be finalised and published until November 2024 at the earliest. The proposed 25 January 2025 start date, which provides only two months to finalise internal requirements, build processes and systems, test and implement, is not achievable. We recommend the 'one-in-all-in' process be aligned to commence from the start of the accelerated smart meter rollout.

Management of Legacy Metering post 30 June 2030

SA Power Networks fully support the exemption of MC's, removing the requirement to complete testing and inspection on legacy metering during the LMRP period, however, we believe this exemption should remain in place beyond the LMRP period.

All Legacy meters post 30 June 2025 will only remain in service because replacement via the LMRP has failed (e.g. due to issues related to access, customer refusal, site safety/defect), consequently it is inefficient to return to the current testing and inspection regime. We expect there will be very low geographic density of legacy meters beyond 2030, resulting in increased cost to service these meters until they are exchanged with smart meters. DNSPs obligations should continue to be restricted to those necessary for operation during this transitional phase, this includes meter reading and meter fault notifications. These meters should remain as outstanding, with the obligation to remain with Retailers to manage the replacement with smart meters as soon as practicable.

Legacy Meter Replacement Plans

SA Power Networks supports the direction within the Draft Determination related to the development and approval of the LMRP (including the overarching LMRP Obligation and LMRP Principles).

The AEMC has defined some key timeframes related to the development of the LMRP within the draft rules. SA Power Networks suggests that the timeframe contained in clause 11.{XXX}.3 (a) be changed from 30 September 2024 to 30 November 2024. The next milestone in the LMRP development is 31 January 2025 when the LMRP is submitted to the AER, therefore this timeframe extension will provide further time for DNSPs engagement prior to developing the actual LMRP document. DNSPs along with SA Power Networks have already commenced engagement with key stakeholders and we planned to continue this engagement during 2024 and therefore do not see this change as impacting or delaying stakeholders' opportunity to contribute to the development and gain visibility of the LMRP.

We also believe some minor improvements could be made to current drafting to provide clarity regarding what detailed NMI level information should be shared with Retailers and Metering Coordinators. SA Power Networks understands that only high level LMRP headline numbers (e.g. yearly numbers, metro vs regional breakdown etc.) should be included within the LMRP document provided to the AER. Detailed NMI level schedules should only be provided to the current Retailer (as defined as the FRMP within MSATS). It would also be the responsibility of Retailers to determine what information at the NMI level they share with the appointed Metering Coordinator. SA Power Networks suggests the AEMC review draft rule wording to provide this clarity.