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Australian Energy Market Commission
Level 15, 60 Castlereagh Street
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Submission on Unlocking CER Benefits Through Flexible Trading – Draft Rule Determination

Executive summary

1. Bluecurrent (formerly Vector Metering) welcomes the Australian Energy Market Commission's (AEMC) draft rule determination and draft rules on *Unlocking CER benefits through flexible trading* (the Draft Determination and Draft Rules, respectively), dated 29 February 2024.

2. In response to the AEMC's proposals in the Draft Determination and Draft Rules, Bluecurrent supports the intent of this reform and its objectives to better integrate consumer energy resources (CER) into the grid. We make the following observations and recommendations:

    a. Taking all factors into consideration, it is our view that further consultation in relation to the implementation of this rule change would result in superior outcomes for consumers.

    b. The complexities for Metering Providers in meeting their obligations in the *National Electricity Rules* (NER), where devices are provided by the customer, will present unique challenges for Metering Providers.

    c. We recommend that the Metering Provider for the secondary settlement point at a type 8 metering installation should be contestable and can be a different party from the Metering Provider at the primary connection point.

    d. We recommend that the AEMC consider using Customer Classification code (Business or Residential) rather than annual consumption at a premise as the means of determining the applicable meter types for CER devices, and the contestability of the role of the Financially Responsible Market Participant (FRMP) at the secondary settlement point.

    e. We recommend that chapter 7 of the NER should provide for the minimum specifications for meter types 8 and 9, rather than leaving it up to the Australian Energy Market Operator (AEMO) to determine their minimum service specifications.

    f. The overall complexity introduced by this proposed reform risks the delivery of cost-effective alternative metering solutions for the customer. We would like to see a model developed that meets the reforms' objectives and simplifies the process for all market participants. This would likely result in a more cost-effective reform. We would be happy to assist in this regard.

3. For retailers, a key enabler of behind-the-meter solutions is cost-effective and compliant metering. Once cost-effective pattern-approved devices or CER devices that have pattern-approved capability become available, retailers will be able to make these products more attractive to the customer. Conversely, we expect that establishing an on-market secondary settlement point will introduce additional costs that will need to be recovered. If the benefits do not outweigh the costs, then retailers and customers will simply revert to the off-market arrangements that currently prevail.

4. Our understanding is that obligations placed on Metering Providers for type 8 and 9 meters will largely remain unchanged (i.e. will be similar to type 1-4 metering obligations). To meet the NER obligations for customer supplied equipment, we expect that Metering Providers will require tight integration with

CER device vendors. Existing metering market participants may find it challenging to provide type 8 and 9 metering services, leaving it to niche providers. This may limit options for retailers and customers in the short term.

5. Given that many stakeholders share similar concerns to those expressed in this submission, we recommend that the AEMC proceed with its proposed changes for type 9 metering for large customers but delay the introduction of type 8 metering until these key issues are better understood and can be resolved. We would be happy to work with the AEMC to help address these issues.

Timing of implementation

6. The AEMC suggests an 18-month timeframe for implementing the rule change, with a proposed commencement date of 2 February 2026. While we consider the impact of these changes on Metering Providers' market systems and internal systems to be moderate, changes to retailer and distribution network service providers' (DNSP) systems could be more significant. We do, however, expect material changes from other initiatives, particularly from the AEMC Metering Services Review which is currently at the draft rule stage. The Metering Services Review Draft Rule will likely impose changes within the same 18-month window, which may prove extremely challenging for the industry to meet. Many businesses have a finite amount of available resources for their work or change programs – a key constraint that governs the pace of service delivery.

7. On this basis, we believe that it would be beneficial for the AEMC to further consult on the implementation of this rule change.

Obligations placed on Metering Providers for new meter types

8. Bluecurrent understands and supports the reform's intent to better integrate CER into the grid. However, we foresee implementation issues, particularly concerning type 8 metering where customers provide their own metering or meter-enabled devices. Our understanding of the Draft Rule is that a customer who has purchased and installed a device and then wishes to participate in a product offered by a retailer requiring the customer's CER data to become 'on-market' will, via their retailer, appoint a Metering Provider to collect and deliver data to the market.

9. This will present challenges for Metering Providers in meeting their obligations, which requires close interaction with the metering installation. Metering Providers typically provide and install a metering device that has been developed closely with metering manufacturers to ensure that all NER obligations, Australian Standards, National Measurement Institute requirements, and jurisdictional Service and Metering Installation Rules can be met. Collectively, these standards support Metering Providers in meeting their NER obligations, which broadly aim to ensure:

    a. The integrity, security, and privacy of the data collected from the meter; and

    b. Timely and consistent collection of data.

10. Metering Provider obligations in the NER are met because Metering Providers ensure that metering manufacturers design metering devices and data collection systems specifically to support these requirements.

11. Customers may purchase and install their own CER device, which has patented approved measurement capability features, but they may not have the features to allow Metering Providers to easily meet all their obligations and protect the integrity of the meter data collected from that device. Below are some examples of features that Metering Providers require but may not necessarily be delivered by a patterned-approved device.

    a. <u>Tamper Alarms</u>: Remotely read meters today are equipped with tamper alarms that notify a Metering Provider when a cover has been removed. Metering Providers rely on this feature to meet NER obligations, ensuring the ongoing physical security of the meter. When an unexpected alarm is triggered, the Metering Provider arranges for a site visit to investigate, inspect, ensure the integrity of the device, and reseal it. It is not clear whether a CER device purchased and installed by a customer will include this feature.

b. Physical Seals: Obligations require that metering devices are fitted with physical seals. Access to these seals is limited and identifies the party that sealed the device. Australian standards and jurisdictional instruments require that electricity meters support the fitting of physical seals. Protection methods assure customers that the measurement of their generated electricity volume is correctly recorded and unaltered by untrained or unqualified personnel. CER devices purchased and installed by customers may not incorporate such physical seals as they are designed for their primary function rather than for metering compliance.

c. Meter Time: Obligations require the measurement time of a meter to align consistently with market time every time the meter is remotely accessed. If the time has drifted, it must be reset to maintain accuracy. A CER device purchased and installed by a customer may or may not allow for the remote resetting of the measurement time, compromising Metering Providers' ability to ensure the accuracy and synchronisation of meter time with market time. Proper alignment with market time assures customers that the price paid, or generation payment received, is correctly assigned the appropriate price.

12. The NER requires Metering Providers to ensure the ongoing integrity of meter data collected from the meter by conducting routine testing and inspection. It is unclear if the NER will provide the authority for this testing to be performed where the asset is owned by the customer. Additionally, it is unclear how a Metering Provider not closely aligned with a CER device manufacturer can conduct routine testing without voiding a customer's warranty. The Draft Determination proposes that retailers should request the deactivation of a secondary settlement point if a malfunction remains unresolved – this should also apply when the customer refuses Metering Provider access to the secondary settlement point. It is also unclear how a Metering Provider would know if there was a malfunction.

13. The Draft Rule proposes that CER devices providing data to on-market processes must meet National Measurement Institute pattern approval. It is our view that this alone is insufficient for the integration of that device into the National Electricity Market (NEM). We assume that the Metering Provider obligations for new metering types will remain largely the same as those for existing meter types (which was confirmed in the recent high-level design forum convened by AEMO). Therefore, a Metering Provider who will take responsibility for a metering installation will expect these CER devices to have more features than those offered by pattern approval.

14. The AEMC should consider how customers will be informed of the compliant devices that can easily be integrated into the NEM before they purchase and install a CER device. If customers are not made aware of this at the time of purchase, they may find themselves unable to use their device to support an on-market product in the future. If this information is to be made available, then the cost and delay of managing an approved device procedure and maintaining a controlled approval register should be considered in the AEMC's cost-benefit analysis.

15. Allowing customers to provide their own CER device introduces a model where other parties are involved in the collection of metering data that will be used for market settlement. Currently, CER devices (e.g. solar PV and battery systems) typically make data available to the customer via the vendor's portal, communicated directly from the device or through the customer's internet connection. Utilising this data appears to be efficient, however, ensuring the integrity of these measurements is challenging unless the Metering Provider is closely aligned with the CER device vendor. This approach would require the Metering Provider to warrant that the vendor's systems and processes meet NER requirements for data integrity – a challenging task given that providing meter data to the NEM is not the primary function of the CER device vendor. If this cannot be negotiated, then the Metering Provider may need to install additional hardware to directly source the data from the device which will require vendor-specific integration. Given the expected variety of devices and vendors, this approach does not seem practical, or possible if the supplier has proprietary/secure systems.

16. Metering Providers could resolve the above issues by entering into commercial agreements with the vendors of such devices to meet NER Metering Provider obligations. However, this could be challenging considering the potential number of vendors providing CER devices. Device vendors primarily focus on selling devices to consumers, and meeting the requirements of the NER for a Metering Provider (who is not their customer) is unlikely to be a priority for them.

17. Unless the Metering Provider is closely aligned with the CER device vendor, as Metering Providers providing metering services to the NEM are today, we expect that challenges related to functionality, interoperability, and device warranty will persist. This will make it difficult for non-vendor aligned Metering Providers to meet the obligation thresholds required to gain AEMO accreditation for these new metering types. We anticipate situations where CER devices installed by customers, which are operating perfectly well for their primary function (e.g. an EV smart charger charging their vehicle) will need to be replaced with another device to allow a Metering Provider to meet its obligations.

18. Given that the proposed new metering types have different and potentially unique characteristics to existing metering types (such as the involvement of the customer as the asset owner), we believe that it is appropriate to review all existing Metering Provider obligations in relation to these meter types to ensure that these do not present barriers that will stifle their adoption. This should include reviewing any requirement for Metering Providers to attend site to investigate issues and loss of communication, and the need to produce estimated reads when communication is lost. Not addressing these barriers will make it more difficult for Metering Providers to service this new market.

19. It is unusual for AEMO to be tasked with determining the definition of minimum specifications for the new meter types. Typically, AEMO does not need to consider the broader factors when considering changes to obligations required by rule changes. Its role is to implement the rules/NER as they are written or as they interpret them – a point that AEMO regularly reminds the industry of. The evaluation of the economic impact of any change to obligations is performed by the AEMC when considering any rule change proposal. Changing the technical requirements for meter types can have significant impact on businesses. Requirements that are 'here today but gone tomorrow' can erode confidence for investment. In our view, the AEMC is the appropriate regulator to undertake detailed analysis of the impact of any changes to the metering requirements.

20. In the Draft Determination, the AEMC expects AEMO to consider other factors in setting requirements for the new meter types, in addition to the minimum set of requirements. These include "international standards, consumer and manufacturer cost impacts, and flexibility for the inclusion of new and emerging technologies." However, we cannot see any mention of the factors that AEMO is expected to take into consideration in the Draft Rule changes.

21. Given our views above, we believe the minimum service specifications for these new metering types should be included in Chapter 7 of the NER, and any changes should be subject to standard rule change consultation processes by the AEMC.

Proposal that metering parties for the primary connection point should assume responsibility for providing new meter types

22. The Draft Rule proposes that the Metering Coordinator at a small customer's premise be the same for both the primary connection point and the secondary settlement point. We have concerns about this approach (page 33 of the Draft Determination).

> "The draft rule provides that the Metering Coordinator (MC) responsible for the small customer's connection point would also be responsible for the settlement points linked to the connection point. The Commission considers given there is only one FRMP, the existing metering role arrangements should be maintained for secondary settlement points."

23. This effectively creates a situation where Metering Providers who offer services for type 4 meters will be compelled to provide services for a secondary settlement point or risk having their primary metering displaced.

24. After assessing the risks and costs associated with type 8 metering obligations, existing metering businesses accredited to provide type 1-4 metering may make a rational business decision not to provide services to the secondary settlement point market. Or they may be unable to gain accreditation from AEMO for type 8 metering services. Consequently, they risk having their existing meters at the primary connection point displaced. Businesses that choose only to provide services to primary connection points (type 1-4 metering) will be excluded from sites requiring the establishment of a secondary settlement point. Conversely, Metering Providers wishing to provide type 8 services only will be forced to also support type 1-4 metering. We anticipate this will limit metering choices for FRMPs at sites where secondary settlement points are present and will create unnecessary meter churn in the market.

25. These issues can be avoided by allowing the FRMP at a small customer's premise to appoint a different Metering Coordinator for the secondary settlement point (i.e. not the Metering Coordinator at the primary connection point). FRMPs can appoint a fully Power-of-Choice type 4 compliant Metering Provider for the primary connection point and a specialist CER type 8 Metering Provider at the secondary settlement point. This approach better supports innovation, provides more choice for retailers and customers, and fosters better competition between Metering Providers.

Use of existing customer annual consumption classifications as the criteria for determining meter types

26. The Draft Rules utilise customer annual consumption classifications of 'Large' and 'Small' to determine the permissible meter types. Type 8 meters are intended for secondary settlement points at Small customer sites, while type 9 meters can be used for both primary connection points and secondary settlement points for Large customers. Type 9 meters also accommodate the aggregation of loads from many meter installations under a single national metering identifier (NMI) to cater for metering loads that are traditionally unmetered, such as streetlights, telco curb-side infrastructure, advertising hoardings, and low-consumption parking sensors.

27. The aggregated load for low-energy devices intended for type 9 metering may not meet the annual thresholds required for classification as 'Large'. Consequently, these NMIs would be classified as 'Small', which would not permit the aggregation of device loads. Additionally, the ability to aggregate volumes of devices together is constrained by other factors, such as loss factors, which are determined by the geographical location on the network and recorded against the NMI. Aggregating devices under a single NMI is constrained to devices that are approximately in the same area. This constraint creates challenges for these devices to qualify as 'Large' and meet the annual volume criteria for Type 9 metering. Market processes validate against this classification to ensure the correct metering is established. Mis-identified NMI classification based on actual annual consumption volumes is likely to cause rejection of FRMP assignment and metering requests.

28. These issues could be resolved by using Customer Classification (Residential, Business) rather than annual consumption volumes. For instance, residential customers would be limited to type 8 metering for the secondary settlement point, while non-residential customers would be limited to type 9 metering for both primary and secondary settlement points, irrespective of annual consumption. Adopting this approach also addresses issues that arise when a customer's annual consumption crosses a threshold and requires reclassification.

Type 8 metering is designed to lower the cost of metering to the customer

29. The complexity introduced by this reform is unlikely to result in cost-effective metering solutions for the customer. If the obligations for Metering Providers remain similar to those for type 4 metering, issues related to site access, access to data, ensuring data security, testing and inspection, treatment of malfunctions, and loss of communications are expected to lead to significantly higher costs for type 8 compared to type 4 metering. Type 8 meters, by their definition, will be difficult to access. Devices such as EV chargers (the predominant use case currently envisaged for type 8 metering) will likely be

located inside customers' garages or behind locked gates, making them challenging to access. Metering Providers today experience access problems at approximately 15% of sites for type 1-4 metering. Negotiating access with the customer at these sites is difficult and time-consuming. We expect that for type 8 metering, this challenge will apply to almost all of these sites.

30. If existing metering related obligations for type 8 remain largely the same as those for type 1-4 metering, any savings in physical metering arrangements for a secondary settlement point will be offset by costs incurred by Metering Providers in meeting their obligations.

31. We note that jurisdictional requirements imposed on customers by DNSPs appear to undermine some of the assumptions made about metering arrangements. The AEMC's decision to adopt a subtractive metering arrangement was designed to deliver lower installation costs for the customer when establishing the secondary metering installation (an argument we did not agree with in our submission on the AEMC's Directions Paper). Energy Queensland has recently updated their connection manual, which dictates wiring requirements for EV chargers. These offer three approaches, but our understanding is that two of these will require customers to connect the EV charger to a dedicated circuit controlled by an external network device or the primary meter at the primary metering installation. This arrangement is likely to require new dedicated circuits to and from the primary metering installation, something subtractive metering was trying to avoid. These arrangements will also require the secondary settlement point circuit to be physically de-energised outside off-peak periods which is likely to create problems for Metering Providers, customers, and CER device vendors when the CER device is de-energised.

Responses to selected consultation questions

Question 1: What should the flow limit be for type 8 meters (when considered per year)? Is 750 MWh per annum per connection point appropriate?

32. Bluecurrent recommends that Customer Classification (referred to in paragraphs 18 and 19) be used rather than annual consumption volumes to determine the proposed type 8 meters. However, should the AEMC decide that annual flow rates should be considered, then we are of the view that setting limits on secondary metering points for residential premises (Small) will serve little purpose as there will be physical constraints at the premise, such as the service fuse on the connection point that will limit flows. We note the proposal to limit flow rates at secondary settlement points to 750 MWh per annum far exceeds what we believe will be physically possible for a Small premise.

Question 2: What role, if any, should Meter Providers have in installing and managing type 8 and type 9 meters?

33. If existing obligations placed on Metering Providers remain largely unchanged for the new meter types, then Metering Providers will need to play a major role in the installation and ongoing management of CER devices. In order for Metering Providers to meet all of their obligations, they will need to be closely aligned with CER device vendors. Please refer to paragraphs 8 – 16.

Question 3: How frequently should AEMO update its specifications and procedures for type 8 and type 9 meters? Should this review be mandated?

34. We believe these requirements are best placed in the NER and should be subject to standard rule change consultation processes. Please refer to paragraphs 17 – 19.

Question 4: Are there instances in which aggregating multiple street lights under a single NMI via a central management system may create issues for settlement?

35. To ensure the integrity of the metering data, the central management system should be operated by an accredited Metering Provider.

Changes to Schedule 7.4

36. We note that the consolidated Draft Rule amendments contain changes to Schedule 7.4 of the NER. These changes appear unrelated to the CER changes proposed by this Draft Rule. We understand that these were requested by AEMO in the rule change request, which states that these had been subject to consultation with Metering Providers. Bluecurrent is unaware of any consultation on these changes and has reached out to other major Metering Providers in the NEM who are also unaware of the origins of this change. We recommend that this change be clarified or removed and included in a separate consultation.

Schedule 7.4 Types and Accuracy of Metering installations

S7.4.1 General requirements

(a) This Schedule 7.4 sets out the minimum requirements for *metering installations*.

(b) When extended range *current transformers* are used, the overall accuracy requirements at loads greater than 100% rated load must not exceed the overall accuracy requirements specified within the *Rules* for 100% rated load.

(c) Extended range *current transformers* must not to be used beyond the limits of their extended range.

(d) For Type 4, 5 and 6 *metering installations* which are direct connected or have *current transformer*(s), the *Metering Provider* is permitted to demonstrate accuracy requirements of the *metering installation* by means of using a generic design. The generic design must consider the error limits for the class accuracy of the equipment and calculated or measured burden or loads to demonstrate compliance. Each generic design must include conditions under which it may be applied.

S7.4.3 Accuracy requirements for metering installations

(a) The maximum allowable overall error (±%) at different loads and power factors is set out in Table S7.4.3.2 to Table S7.4.3.7.

(b) All measurements in Tables S7.4.3.2 – S7.4.3.7 are to be referred to 25 degrees Celsius.

(c) The method for calculating the overall error is the vector sum of the errors of each component part (that is, a + b + c) where:

(1) a = the error of the voltage transformer and wiring;

(2) b = the error of the current transformer and wiring; and

(3) c = the error of the meter.

(c) If compensation is carried out then the resultant metering data error shall be as close as practicable to zero.

(d) The maximum allowable error of a type 5 or type 6 *metering installation* may be relaxed in the *metrology procedure* to accommodate evolving technologies providing that such relaxation is consistent with any regulations published under the *National Measurement Act*.

(e) Where a subtractive metering arrangement is used (due to *secondary settlement points* or *child connection points*) the annual energy throughput is the total throughput for the *metering installation*, not the net throughput.

Discovery of existing settlement points

37. Bluecurrent recommends that Metering Providers for secondary settlement points should have extended rights to view NMI standing data on a primary connection point. This will be used when the FRMP for the primary connection point has made arrangements for the site to be de-energised. When this occurs, the Metering Provider for the secondary settlement point will lose remote connectivity with the secondary device. To determine what caused this issue, the Metering Provider must be able to check MSATS (Market Settlements and Transfer Solutions) to see if either the primary NMI has been de-energised at the service fuse or remotely disconnected at the meter. In both instances, this will be reflected in MSATS NMI standing data. Should this be the case, the Metering Provider will avoid deploying resources to the field to investigate and will be able to take the appropriate actions required under the NER.

Concluding comments

38. We are happy to further discuss any aspects of our submission with the AEMC. Please contact Paul Greenwood (Industry Development - Australia) at Paul.Greenwood@vectormetering.com in the first instance.

39. No part of this submission is confidential, and we are happy for the Authority to publish it in its entirety.

Yours sincerely

Neil Williams
Chief Executive