AUSTRALIAN ENERGY MARKET COMMISSION

RULE

Draft rule determination

National Electricity Amendment (Unlocking CER benefits through flexible trading) Rule

National Energy Retail Amendment (Unlocking CER benefits through flexible trading) Rule

Proponent
AEMO

29 February 2024

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About the AEMC

The AEMC reports to the energy ministers. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the energy ministers.

Acknowledgement of Country

The AEMC acknowledges and shows respect for the traditional custodians of the many different lands across Australia on which we all live and work. We pay respect to all Elders past and present and the continuing connection of Aboriginal and Torres Strait Islander peoples to Country. The AEMC office is located on the land traditionally owned by the Gadigal people of the Eora nation.

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Summary

1 The Australian Energy Market Commission (AEMC) has made a draft determination to make more preferable draft electricity and retail rules (draft rules) for the unlocking CER benefits through flexible trading rule change.

2 This determination is in response to the rule change request submitted by the Australian Energy Market Operator (AEMO). This rule change proposal was developed as part of the Energy Security Board's (ESB) CER implementation plan.

3 The Commission considers this rule change is a critical step, within the broader CER workstream, that will help consumers realise the most value from their customer energy resources (CER) and, in turn, contribute to a more reliable, lower emissions and lower cost energy system.

4 We are seeking feedback on our draft determination and more preferable draft rules by **11 April 2024**. There are a variety of ways to provide feedback including participating in workshops or bilateral meetings to providing formal submissions.

CER plays an important role in the NEM transition

5 Australia's energy landscape is being transformed by the proliferation of CER and consumers choosing to use resources in their homes and businesses to exercise greater control over their energy bills.

6 Around one in four Australian homes have solar panels, with one in two expected by 2040. 3.19 million total solar rooftop PV systems have been installed for residential and small business customers in Australia and more than 50,000 small-scale battery systems have been installed in the past seven years. There is also predicted to be a surge in electric vehicles in Australia, with approximately 22 million expected to be taken up by 2050.

7 These trends represent an enormous opportunity and a pivotal moment for Australia's energy future. CER, along with distributed energy resources (DER) such as neighbourhood batteries, have an important role to play in the power system and will help to reduce overall system costs, improve reliability and achieve a secure, low-emission energy supply for all consumers.

8 AEMO's Electricity Statement of Opportunities (ESOO) 2022 indicates that coordinated CER can support reliability by meeting energy system needs and reducing the incidence of 'unserved energy' events where supply cannot keep up with demand.

9 If CER is integrated well, there will be positive outcomes for all market participants and flow-on benefits for consumers, such as cost-efficiency and reliability for consumers, including those who have limited or no access to CER technology. A range of studies have estimated the net benefit of effective integration and coordination of CER to be between $1 billion and $6.3 billion by 2030-2040 (CSIRO and Baringa consulting, 2019; ARENA, NERA consulting, 2022). The ENA Electricity Transformation roadmap highlighted that $16 billion in network infrastructure investment would be avoided by CER/DER orchestration. Consultant Energeia is undertaking further analysis for the AEMC looking at the costs and benefits of increased integration of CER flexibility – both to consumers and the system. Further information about this work is provided in Energeia's report accompanying this determination - Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024.

10 To support this transformation, energy market bodies are driving a number of interrelated reforms that aim to integrate and realise the potential of these resources. The ESB Consumer Energy Resources and the Transformation of the NEM report sets out key elements of this work plan, a

number of which are being delivered by the AEMC. A CER Taskforce convened by Energy Ministers is developing a future CER implementation plan that will further define and drive the CER integration actions needed.

The draft rules are critical to the successful integration of CER in the NEM

11 This rule change is critical to realising the broad potential of CER. It would make a series of relatively modest changes that would allow consumers or their service providers to manage CER in ways that provide the greatest benefit to the customer and to the energy system as a whole.

12 Specifically, the proposed changes would create new arrangements for:

- large customers to choose multiple energy service providers for their premises
- 'flexible' CER (e.g. rooftop solar, batteries, electric vehicle (EV)) to be identified and managed separately from other 'passive' consumer loads (e.g. lights, fridges) in the energy market, and
- the in-built measurement capability in technology such as streetlights and EV chargers to be used instead of installing additional meters, that would allow for the measurement and management of energy use at a lower cost.

13 The key benefits of this rule change include:

- Supporting consumers to take up different products and services for their CER which helps them to reduce consumption costs or improve the value they can get from their assets
- Promoting innovation and competition by reducing regulatory and cost barriers for market participants to provide wholesale energy, ancillary services, and network services, and
- Supporting more CER integration by making it easier for CER to be identified and managed separately, which helps deliver reliability, security, and emissions reduction, and lowers costs for all consumers.

14 The costs associated with the implementation of the proposed draft changes are expected to be low mainly because existing systems will be leveraged. While the total benefits and costs are an important factor informing this draft determination, we also assessed the impacts on consumers with and without CER.

15 Energeia's modelling indicated that there are net benefits for all customers if around 14 per cent of AEMO's ISP forecast of flexible CER is integrated. This equates to approximately 157,000 additional devices in each year to 2043. We also found benefits flow to consumers who do and do not invest in CER.

16 For both the large customer and small customer draft rule changes, the net benefits exceed the costs. While this is an important consideration, the Commission also recognises that the rule is an essential step that will open up opportunities for innovation and competition and, along with other reforms to integrate CER, it will enable greater benefits for the power system and all consumers.

There are three key areas in this draft determination and draft rules

17 The draft determination sets out how the more preferable draft rules would work and how they are different from the proposed rule change request for the three core areas:

1. creating an enduring framework that allows large customers to choose multiple energy providers for their premises
2. opportunities to optimise CER flexibility for small customers (households and small business), and
3. enabling measurement of energy flows using in-built technology.

18 The Commission has taken into account stakeholder feedback through public forums, technical working group workshops, and bilateral meetings with industry bodies and individual stakeholders. Stakeholder feedback is discussed in each chapter of this determination.

19 The Commission also considered the cost benefit analysis undertaken by Energeia, and implementation considerations for both market participants and the market operator (AEMO). The draft determination addresses additional opportunities raised by stakeholders during the consultation process to date.

Creating an enduring framework for allowing flexible trading with multiple energy service providers at large customers premises

20 The Commission's draft determination is to create a new framework that enables large customers to engage multiple energy service providers at their premises. For consumers, flexible trading means the ability to take up different product and service offers for their CER. For the industry, it means consumer resources and consumption can better participate in the wholesale energy and ancillary services market and for network services.

21 Currently, large customers can engage multiple energy service providers by using the embedded network framework or by establishing two connection points to the distribution network to obtain a second National Metering Identifier. This allows CER to participate in the wholesale market through a small generation aggregator. Some consumers also engage third-party aggregators to participate in Frequency Control Ancillary Services (FCAS) markets via VPP projects.

22 The Commission notes that the embedded network framework was not set up for the purpose as outlined above and that these draft rules would provide a more enduring framework in the NER. That is, the draft rules remove the need for large customers and their agents to use an embedded network to get a second NMI without a second connection to the distribution network. The Commission notes that the embedded network exemption guidelines and framework are being reviewed by the AER. Some jurisdictions have also undertaken their own reviews of embedded networks.

23 The draft framework would be voluntary, have lower barriers to entry than existing options, and leverage existing market system arrangements to minimise implementation costs. The Commission has carefully considered the market arrangements, technical requirements, and roles and responsibilities under this option. These details and stakeholder feedback on the proposed changes are set out in Chapter three.

Opportunities to optimise CER flexibility for small customers (households and small businesses)

24 The Commission also noted in the Directions paper that it would consider options to improve how flexible CER is separately identified and managed in the market for households and small businesses, and the rule changes that would be required to implement these. The Commission looked at three options:

- enabling flexible CER to be market-connected through the establishment of a second settlement point at a single connection point
- using non-market devices for CER measurement and reward, and
- making it easier to establish two connection points to the distribution network at a single premises.

25 The Commission has made more preferable draft rules that would enable small customers with CER devices to separate passive and flexible loads and choose how they want to participate in the market (i.e. choose retail products for flexible CER that are different from those for the rest of their

home). Retailers would have visibility of the value of flexible CER and can use this to participate in the wholesale market, provide network services, and offer different products and services to small customers.

26 The draft rules would enable:

- the establishment of secondary settlement points without the need for a second physical connection to the distribution network. This will facilitate greater separation and visibility of flexible CER for consumers and market participants, and
- consumers to use the in-built measurement capability in technology such as streetlights and EV chargers instead of installing additional meters, which allow for the measurement and management of energy use at a lower cost.

27 This option would be voluntary and based on consumer choice. The Commission has also considered the market arrangements, technical requirements, and roles and responsibilities needed for this option. Framework details and stakeholder feedback are set out in Chapter four.

28 As part of its analysis, the Commission has determined that it will not make draft rule changes related to three options:

- **Using non-market devices for CER measurement and reward.** Some households and businesses are managing CER behind the meter. They use measuring devices that measure the CER but are not approved under the National Measurement Act (NMA), not permitted by AEMO (i.e. MASS for providing FCAS), not permitted by the NER, and/or not recognised by AEMO market systems. The NMA requires that only approved meters are used for billing, and these restrictions cannot be altered through changes to the NER/NERR. Enabling a secondary settlement point and new metering options (which would seek to receive NMA approval) provide a better framework for CER integration.
- **Establishing two physical connection points to the distribution network.** The Commission proposes to not make rule changes for this option because we note that DNSPs have existing flexibility in the NER to offer different network service charges for second connections, where efficient. Further, we consider that network and retail tariff arrangements for CER integration should be part of the AEMC's proposed review of network and retail pricing to examine further opportunities to improve consumer incentives for CER flexibility. We also note that under the national EV strategy, officials will work with DNSPs to investigate how service and installation rules can be streamlined. This is the appropriate forum to consider issues around jurisdictional network connection arrangements.
- **Using multi-element smart meters to separately identify and measure CER.** We determined not to progress this option further based on costs, benefits and implementation considerations. Key barriers include limitations in AEMO systems to separate data streams and significant and costly reconfiguration of AEMO and market participant IT systems that would be required.

29 Further details about the reasons for the Commission not pursuing these options are set out in Chapter four.

Enabling measurement of energy flows using in-built technology

30 The Commission has developed a more preferable draft electricity rule that would create two new meter types with lower minimum specifications to enable technology with in-built measurement capability to be used for settlement and billing. These meter types could be used for technology such as public lights, public EV chargers, and by households and businesses (i.e. EV chargers).

31 The Commission anticipates that these new arrangements would support the uptake of EV chargers for residential, large, and public uses by removing the need to install a type 4 smart meter. It would also incentivise the uptake of smart devices for currently-unmetered loads such as streetlights.

32 The main features of the new meter types are:

- they would be voluntary to use
- the meter types would have lower minimum specifications than type 4 meters and these specifications would be determined in AEMO procedures, guided by principles in the NER, and
- the in-built measurement capability in the technology would require National Measurement Institute approval.

33 More detail on these arrangements and stakeholder feedback on these arrangements are provided in Chapter five.

The draft rules would promote the national energy objectives

34 In making our more preferable draft rules, we have considered the national electricity objective (NEO) and the national energy retail objective (NERO) by applying five assessment criteria that we outlined in the Directions Paper. We consider the draft rules would meet the assessment criteria in these ways:

- **Outcomes for consumers.** The draft rules would support small and large consumers to manage their energy costs and generate, consume, store, and trade energy according to their preferences and needs. They would also enable direct measurement of public assets such as streetlights, contributing to energy efficiency and energy cost reductions.
- **Increasing innovation and flexibility**. The draft rules would support innovation and flexibility in energy products and service offerings for consumers looking to use their flexible CER in different ways. They would also support innovation in market participant business models for flexible CER, by making it easier for market participants to have visibility of flexible CER and to access energy markets.
- **Principles of market efficiency, in particular, competition**. The draft rules would support competition in the energy retail sector by lowering barriers for large customers to participate in flexible trading with multiple energy service providers. They would also unlock new opportunities for market participants to use flexible CER and capture the additional value CER offers in the wholesale energy and ancillary services market by reducing transaction costs. The draft rules would also support networks to procure network services from flexible CER.
- **Impacts on safety, security, and reliability**. The draft rules would contribute to system reliability by facilitating the integration of flexible CER into the power system. The draft rules may enable an aggregated resource that the market operator (AEMO) could use to help the system remain secure and reliable.
- **Implementation costs and considerations.** The draft rules have been developed with the aim of minimising costs across the supply chain while creating new opportunities to separate and manage CER and utilise in-built measurement capability in assets - including CER assets.
- **Emissions reductions.** The rule changes would contribute to emissions reductions by increasing opportunities for CER to be used for market and grid services. For example, CER could shift 'load' from higher-emissions times of day (e.g. charging EVs overnight) to low-emissions times of day when cheap renewable energy is abundant. It may also make it easier for orchestrated CER to provide low-emissions generation at times of high grid demand thus

potentially displacing fossil-fuel power generation that would have been required otherwise. The draft rules would also support energy efficiency of public assets such as streetlights, leading to emissions reductions through reduced energy consumption.

The Commission has considered Energeia's cost-benefit modelling in making this determination

35 We engaged Energeia to assess the costs and benefits of the proposed changes for these rule changes. As noted, this work has informed the Commission's draft determination and our analysis.

36 Energeia's key findings are:

- System costs associated with this rule change are relatively small.
- As outlined above, for the benefits to be realised, a relatively small proportion of flexible CER would be needed to be integrated into the power system. Around 14 per cent of the ISP forecast of flexible CER devices would need to acquire a NMI which is around 157,000 additional devices each year to 2043.
- The benefits are most likely realised from the uptake and use of batteries by both small and large customers.
- The rule changes would deliver benefits to consumers who participate in CER flexibility and to consumers more broadly.
- The benefits for consumers (both small and large consumer segments) are likely to come from lower investment in generation and lower wholesale costs, reduced network expenditure and associated network prices, and reduced metering costs (e.g. using in-built metering). Energeia's analysis does not include potential benefits from reduced barriers to entry, including greater choice, lower prices, and more innovation, which could increase the market benefits for all consumers.
- For the proposed arrangements related to smart streetlights and kerbside EV chargers, the rule change could deliver $106m in benefits over 20 years (NPV), including benefits from reduced emissions. These benefits would primarily be derived from reduced metering costs, metering installation costs, maintenance costs, and wholesale costs and emissions reductions.
- In the future, greater benefits would be unlocked with cost-reflective prices and by AEMO enabling the proposed in-built measuring capability to be Market Ancillary Service Specification (MASS) compliant so that market participants and consumers can access FCAS markets at lower cost.

37 A summary of Energeia's findings is at Chapter six and the full analysis is published alongside this determination. See Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Draft Report, Energeia, 29 February 2024.

Implementation considerations

38 After we make the final electricity and retail rules for this rule change, a suite of procedures and guideline changes will need to be undertaken by both AEMO and AER to ensure that the policy can be implemented in full. These procedures and guidelines will specify operational and technical requirements, as well as transitional arrangements, to ensure that the rule changes would operate as intended and would be as accessible as possible to consumers and market participants.

39 Noting that AEMO and the AER will be required to undertake consultation processes in relation to

some of these procedures and guidelines and that market participants will also need to update their systems, we anticipate that the rule changes will require around 18 months for implementation, and therefore the draft rules propose a commencement date of 2 February 2026.

Next steps

40 As outlined, we are seeking feedback on our draft determination and draft rules by **11 April 2024**.

41 There are a variety of ways to provide feedback, from participating in working groups and bilateral meetings to providing formal submissions. Refer to how to make a submission below.

How to make a submission

We encourage you to make a submission

Stakeholders can help shape the solution by participating in the rule change process. Engaging with stakeholders helps us understand the potential impacts of our decisions and contributes to well-informed, high quality rule changes.

How to make a written submission

Due date: Written submissions responding to this draft determination and draft rules must be lodged with Commission by **11 APRIL 2024**

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code ERC0346**.** [1]

Tips for making submissions on rule change requests are available on our website.[2]

Publication: The Commission publishes submissions on its website. However, we will not publish parts of a submission that we agree are confidential, or that we consider inappropriate (for example offensive or defamatory content, or content that is likely to infringe intellectual property rights).[3]

Next steps and opportunities for engagement

There are other opportunities for you to engage with us, such as one-on-one discussions or industry briefing sessions.

Table 1: Timetable for the rule change and points of stakeholder consultation

Stage	Timeline
Commission publishes Draft Determination and more preferable draft rules	29 February 2024
Stakeholder submissions due	11 April 2024
Stakeholder consultation	March - April 2024
Commission publishes Final Determination and more preferable final rules	July 2024
Proposed implementation date for the rules	2 February 2026

You can also request the Commission to hold a public hearing in relation to this draft rule determination.[4]

Due date: Requests for a hearing must be lodged with the Commission by 7 March 2024.

How to request a hearing: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code ERC0346**.** Specify in the comment field that you are requesting a hearing rather than making a submission.[5]

1 If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission.
2 See: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3
3 Further information about publication of submissions and our privacy policy can be found here: https://www.aemc.gov.au/contact-us/lodge-submission
4 Section 101(1a) of the NEL and section 258(2) of the NERL.
5 If you are not able to lodge a request online, please contact us, and we will provide instructions for alternative methods to lodge the request.

For more information, you can contact us

Please contact the project leader with questions or feedback at any stage.

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1 The Commission has made a draft determination

The Australian Energy Market Commission (AEMC or Commission) has made a draft determination to make more preferable draft electricity and retail rules (draft rules) in response to the rule change request submitted by the Australian Energy Market Operator (AEMO). The AEMO rule change proposal was developed as part of the Energy Security Board's (ESB) post 2025 NEM recommendations and consumer energy resources (CER) implementation plan. The draft determination also addresses additional opportunities raised by stakeholders during the consultation process.

The draft rules seek to increase the flexibility and trading of CER[6] to further unlock value for consumers and for specific products and services - which can reward and harness the value of CER - to be developed. They also aim to facilitate better integration of flexible CER into the power system to deliver a more reliable and secure energy system that would benefit all consumers.

The anticipated timeline for implementation is 18 months, with a commencement date of 2 February 2026 set out in the draft rules.

We are seeking feedback on our draft determination and draft rules by **11 April 2024**. There are a variety of ways to provide feedback, from participating in working groups and bilateral meetings to providing formal submissions.

This draft determination has the following chapters:

Chapter one (this chapter) provides an overview of what our draft rules seek to introduce and the inputs that we have considered in forming the draft rules, including stakeholder feedback and Energeia's analysis of the costs and benefits of the proposed changes.

Chapter two explains our assessment framework and summarises why the Commission considers the draft rules would contribute to achieving the energy objectives.

Chapter three sets out the supporting arrangements to introduce flexible trading with multiple energy service providers for large customers.

Chapter four details the supporting arrangements for optimising the value of CER flexibility for small customers.

Chapter five sets out our draft arrangements for measuring energy flows from in-built technology (e.g. street lights, EV chargers, and other street furniture).

Chapter six summarises the draft Energeia results on the cost and benefits analysis for the draft rules.

Chapter seven outlines implementation considerations.

There is also a set of Appendices including:

- rule making process
- regulatory impact analysis - summary
- legal requirements to make a rule
- summary of the draft rules
- summary of other issues raised in submissions, and
- abbreviations and defined terms.

6 in the Directions paper we outlined CER to include responsive/flexible load and generation at a consumer's premises (e.g. roof top solar, batters, HEMS, as well as controllable hot water systems. It can also include responsive load at large customer's premises such as HVAC.

1.1 Our draft rules provide new arrangements supporting the use and integration of flexible CER in the NEM

The draft determination sets out policy positions and draft rules covering three areas:

- Flexible trading[7] with multiple energy service providers at large customer premises.
- Opportunities to optimise CER flexibility for small customers, and
- Measuring energy flows from in-built technology (streetlights, EV chargers, other street furniture).

1.1.1 Flexible trading with multiple energy service providers at large customer premises

The draft framework enables large customers to engage multiple energy service providers[8] at their premises. This would provide large customers with increased choice from greater competition as energy providers could offer prices or incentives for these customers to operate their flexible load at lower cost. Businesses could also benefit from these changes, if they want more bill predictability and simpler retail tariffs for their inflexible electricity use, to optimise the value of flexible loads and generation assets by participating in energy markets, or are seeking greater value streams from co-located generators or batteries to reduce payback periods. Further, it may promote more innovation from energy service businesses and provide opportunities for energy service providers to offer services to distribution network providers and capture additional value from participating in wholesale energy and ancillary services where they currently are not.

The framework aims to leverage arrangements used under the current embedded network framework, including these features:

- It is voluntary.
- There is a secondary settlement point and subtractive settlement, and
- There is no regulated contractual relationship between FRMPs.

The draft rules also seek to minimise implementation costs for market participants and market system costs by utilising existing system arrangements.

Currently, large customers can engage multiple energy service providers by using the embedded network framework or by establishing two connection points to the distribution network to obtain a second NMI. As noted in the Directions Paper, some energy service providers use these consumer resources to provide Frequency Control Ancillary Services (FCAS) in the ancillary service markets. This does not necessarily require the CER to be separately identified but a range of requirements need to be met under the market ancillary services specification.

We noted that some energy service providers are using the embedded network framework to obtain a second connection point and national metering identifier allowing consumer resources to participate in the wholesale market as a small generation aggregator. The Commission notes that the embedded network framework was not set up for this purpose and that there is an opportunity to provide a more appropriate and enduring framework - that is, reduce the need to use the embedded network framework to get a second NMI without having to get a second connection to the distribution network. The future of the embedded network framework is uncertain as it is being reviewed by the AER.

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7 Flexible trading of CER refers to activities where consumers can take up different product and service offers for their CER. For the industry, it means consumer resources can be used more easily in the wholesale energy and ancillary services market and for network services.

8 For the purposes of this draft determination, an energy service provider can be for example a Market Customer, SGA and/or retailer. From 3 June 2024, integrated resource providers will be introduced into the NER, and these would also be covered by the concept of "energy service provider" for the purposes of this determination.

This draft flexible trading framework would offer a mechanism for flexible trading for large customers and their energy service providers with lower barriers to participation than existing approaches.

Refer to Chapter three for a detailed description of the draft arrangements for large customers.

1.1.2 Opportunities to optimise CER flexibility for small customers

The draft rules would enable the establishment of a secondary settlement point/s at small customer premises, while maintaining existing consumer protections. This will provide the opportunity for household and small business to use their CER assets to generate, consume, store, and trade energy according to their preferences. For example, consumers with CER devices would be able to separate their passive and flexible loads and make choices on how they want to participate in the market (e.g. choose products for their CER versus the rest of their home). Consumers with and without CER assets will benefit from a lower cost power system.

Further, retailers would have better visibility of the value of flexible CER and can use this to participate in the wholesale market, provide network services, and offer different products to small customers. It would also enable assets with in-built measurement capability to be used for settlement and billing (subject to National Measurement Institute approval). For example, using equipment inside an EV charger to measure energy consumption by the EV charger removes the need for a separate meter.

We note that the draft rules do not include changes related to using non-market devices for CER measurement and reward, establishing two physical connection points to the distribution network, and use of multi-element smart meters to separately identify and measure flexible CER. The Commission's reasons are outlined in Chapter four.

Refer to Chapter four for a detailed description of the draft arrangements for small customers.

1.1.3 Measuring energy flows from in-built technology (e.g. streetlights, EV chargers, other street furniture)

The rule change would create a new meter type, similar to a type 4 meter, but with lower minimum specifications. This would enable technology with in-built measurement capability to be used for settlement and billing. This meter type could be used for technology such as street lights, public EV chargers, and for households and businesses (e.g. EV chargers). The in-built measurement capability in the technology would require National Measurement Institute approval. The supporting arrangements may differ for the different use cases in certain circumstances (e.g. households vs street lights).

AEMO proposed this rule change in response to advancements in measurement technology in assets such as EV chargers and public streetlights. This new type of meter would support the uptake of EV chargers for residential, large and public uses by removing the need to install a Type 4 smart meter. Instead, the in-built measurement capability would be recognised for settlement and billing purposes- reducing installation costs.

Creating a new meter type would also incentivise uptake of smart devices for unmetered loads such as smart street lights. As an example, smart street lights with metering recognised for settlement purposes have the potential to reduce customer costs through energy efficiency (dimming technology), reduce greenhouse gas emissions, and enable more accurate settlement. Refer to Chapter five for a detailed description of the draft arrangements.

1.2 Energeia's cost benefit analysis and stakeholder feedback have shaped our determination

The Commission's draft decision has considered Energeia's cost benefit analysis for this rule change and stakeholder submissions in response to the Directions paper[9] and consultation paper.[10] The decision has also been informed by discussions through a range of workshops and direct consultation with industry participants and consumer groups.

Further detail on the rule-making process is included in Appendix D and Appendix F contains a summary of stakeholder comments that are not addressed elsewhere in this determination.

1.2.1 Energeia cost-benefit analysis of the rule change

As outlined in the Directions Paper, we have engaged Energeia to undertake a cost and benefit analysis for the proposed changes under these draft more preferable rules.

As part of its decisions, the Commission has aimed to consider a least-cost approach for all aspects of this rule change, recognising that this rule change is a critical step and a range of other reforms as outlined on the CER broader implementation plan[11] are required to achieve CER integration in the power system. We have considered the options in this rule change on the basis that they:

- are voluntary for small and large consumers
- impose low costs on consumers and market participants, and
- require achievable uptake in order to deliver supply chain (i.e. consumer/system/network) benefits.

Broadly, Energeia's analysis found that this rule change would deliver benefits to households, small and large businesses (including councils) at a relatively low cost to the system and broader consumer base.

A detailed summary of Energeia's findings are provided in Chapter six and in Energeia's draft reports published alongside this draft determination.[12]

1.2.2 Stakeholder feedback to the Directions paper, workshops and other consultation

This section outlines key stakeholder feedback received through submissions, public forums, and working groups for the three core areas outlined in the Directions Paper. Based on stakeholder submissions, feedback at workshops and consultation directly with stakeholders, the Commission has refined and articulated these policy positions and prepared the draft rules - detailed in chapters three to five.

Stakeholders expressed mixed support for creating a new way to separately identify and manage CER. Some noted that it would be key to innovation, increasing consumer choice for different CER products and services.[13] In particular, smaller retailers noted that it would create opportunities to offer different products and services to residential customers to manage their flexible loads.

9 Refer to the Directions Paper

10 Refer to the Consultation Paper

11 Refer to the Post 2025 DER Implementation Plan

12 Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024; Measuring Energy Flows from In-Built Technology (Streetlights, EV Chargers, Other Street Furniture) Analysis - Draft Report, 29 Feb 2024.

13 Submissions to Directions Paper: PIAC, p.5; Energy Locals, p. 2; Intellihub, p.3; Master Electricians, p. 3.

Networks also noted that it would offer a more cost effective alternative to provide CER[14] and would create opportunities to move to more sophisticated tariff arrangements.[15]

Others noted that it has the potential to create complexity and impose costs where options to separate CER already exist.[16] Some stakeholders noted that the proposal was technically feasible and if the proposal progressed, it would be important to consider implementation costs and technical arrangements.[17] Some networks also emphasised the need for any arrangement to not adversely affect network operations or hinder the ability of CER devices to respond to DOEs.[18]

A number of stakeholders also noted that the Commission should focus on related reforms areas such as interoperability, network tariffs, dynamic operating envelopes, smart meter delivery, and retail pricing. For example, several submissions noted that if the aim of CER integration is to increase network visibility and energy flow management, the 'integrating price-responsive resources into the NEM' rule change is more critical.[19] The Commission notes that other reforms are required to optimise the full potential of flexible CER and are working with officials on reforms where they sit outside AEMC remit.

Stakeholders generally expressed strong support for the decision to not progress the multiple FRMPs for small customers. There was mixed support for the proposal to enable multiple FRMPs at large customer premises. Those who supported noted that it would support competition for different products and service for managing flexible loads, would consumer choice of FRMPs and products and services, and would lead to network reliability benefits through improved visibility of subloads.[20]

Some retailers raised concerns regarding risks of unpredictable loads and hedging.[21] Networks expressed concerns about safety considerations in terms of disconnection and load switching, technical requirements for secondary settlement points for large customers, and other network system changes.[22] Several stakeholders also expressed support for the embedded network framework continuing to be used by large customers to engage in flexible trading.[23] This feedback is addressed as part of the outline of proposed arrangements for the framework for flexible trading with multiple energy service providers at large customer premises in Chapter three.

Most stakeholders supported the development of a framework for a new minor energy flow meter for street lighting. They noted that costs need to be minimised to make this feasible (noting implementation costs including purchasing, installing, and managing new meters, managing data, and upgrading network systems). Supporters pointed to benefits including improved energy efficiency, cost reductions, settlement accuracy, and better allocation of unaccounted-for energy.[24] This feedback is addressed as part of the outline of proposed arrangements for new meter types to enable measurement of energy flows from in-built technology in Chapter five.

14 Submission to Directions Paper: Joint NSW DNSP Response, p.5.
15 Submissions to Directions Paper: SA Power Networks, p.3.
16 Submission to Directions Paper: AEC, p.2; EUAA, p.1; Tesla, p.3.
17 Submissions to Directions Paper: AER, p.6.
18 Submissions to Directions Paper: Joint NSW DNSP Response, p.5; SA Power Networks, p.2; Citipower & Powercor Australia & United Energy, p. 1.
19 Submissions to the Directions Paper: Tesla, p.3; Shell, p.2; Red Energy, p.3.
20 Submissions to Directions Paper: PIAC, AEMO, CEC, Flow Power, Enel X, Alinta.
21 Submissions to Directions Paper: Shell Energy, p.2-3; Red Energy & Lumo Energy, p.4.
22 Submissions to the Directions Paper: Energy QLD, AusNet, Joint NSW Joint Response, Tas Networks
23 Submissions to Directions Paper: Shell Energy, p.3; Energy Australia, p. 4; AGL, p.3; Origin, p. 2; AEC, p.1.
24 Submissions to Directions Paper: Retailers (Origin, Energy Qld, Momentum), lighting and CER providers (Schreder, Signify, Connected Light Solutions, Master Electricians, OrangeTek), Consumer advocates (IPWEA, Lighting Council Australia, Australian Smart Communities Association, Qld and SA departments of transport).

A large proportion of stakeholders provided feedback that all policy options should be supported by comprehensive cost-benefit modelling. The draft findings of Energeia's cost-benefit analysis are summarised in Chapter six.

1.3 Our draft determination would support the broader goals of CER optimisation and integration

As outlined above, and in our Directions Paper, this rule change forms one of the many CER reforms underway.

The Commission notes that this rule change is a necessary step, but a range of other reforms are required to unlock the full potential of CER for consumers and the system. Other reforms and reviews that intersect with this rule change include Integrating price responsive resources (IPRR),[25] Accelerating smart meter deployment,[26] AER's guidelines on Flexible export limits, and jurisdictional official's work on Interoperability.

Other reforms that have not commenced include a rule change proposal for a rule change proposal for access to real-time energy and operational data, and the AEMC's proposed review of the role of network and retail pricing to consider further opportunities to improve consumer incentives for CER flexibility. This was outlined in Chapter two of the rule change Directions Paper.[27]

We note that access to real-time energy data and interoperability are a critical part of this transition and will require further consideration. Further, information and tools for consumers to make decisions that suit their needs are key to protecting consumers through this transition and are on the CER reform agenda, being considered by officials and work of Energy Consumers Australia.

The Energy Security Board's end-of-program CER report "Consumer Energy Resources and the Transformation of the NEM" published 7 February 2024, outlines this ongoing CER reform work.

25 Refer to the Integrating Price Responsive Resources project page.
26 Refer to the Accelerating smart meter deployment project page.
27 Refer to the Directions Paper for this rule change.

2 The draft rules would contribute to the energy objectives

2.1 The Commission must act in the long-term interests of energy consumers

The Commission can only make a rule if it is satisfied that the rule will or is likely to contribute to the achievement of the relevant energy objectives.[28]

For this rule change, the relevant energy objectives are the NEO and NERO.

The NEO is:[29]

> 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—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system; and
>
> (c) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The NERO is: [30]

> to promote efficient investment in, and efficient operation and use of, energy services for the long term interests of consumers of energy with respect to—
>
> (a) price, safety, reliability and security of supply of energy; and
>
> (b) the achievement of targets set by a participating jurisdiction—
>
> (i) for reducing Australia's greenhouse gas emissions; or
>
> (ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The targets statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the energy objectives.[31]

On this basis, and as discussed further below, the Commission has made more preferable draft rules that would better contribute to achieving the NEO and NERO than the rule changes proposed in AEMO's rule change request.

Chapters three to five provide further information on the Commission's decisions and responses to stakeholder feedback.

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28 Section 88(1) of the NEL and section 236(1) of the NERL.

29 Section 7 of the NEL. The NEO was updated on 21 September 2023 to include paragraph (c), with the introduction of the *Statutes Amendment (National Energy Laws) (Emissions Reduction Objectives) Act 2023*. We have applied the updated NEO in this draft determination, in accordance with that Act and our emissions guidance. This is a change from previous papers for this project, which applied the old NEO.

30 Section 13 of the NERL. As with the NEO, the NERO was updated on 21 September 2023 to include paragraph (b). We have applied the updated NERO in this draft determination, in accordance with the Emissions Act and our emissions guidance. This is a change from previous papers for this project, which applied the old NERO.

31 Section 32A(5) of the NEL and section 224A(5) of the NERL.

2.2 We must also take these factors into account

2.2.1 We have considered whether to make more preferable rules

The Commission may make a rule that is different, including materially different, to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule is likely to better contribute to the achievement of the NEO and NERO.[32] For this rule change, the Commission has made more preferable draft rules. The reasons are set out in section 2.3 below.

2.2.2 We have considered the consumer protections test for this rule change

In addition to applying the NERO, the Commission must, where relevant, satisfy itself that the rule is "compatible with the development and application of consumer protections for small customers, including (but not limited to) protections relating to hardship customers" (the consumer protections test).[33] Where the consumer protections test is relevant in making a rule, the Commission must be satisfied that both the NERO test and the consumer protections test have been met.[34] If the Commission is satisfied that one test, but not the other, has been met, the rule cannot be made (noting that there may be some overlap in the application of the two tests).

The Commission is satisfied that the more preferable draft retail rule meets the consumer protections test. The Commission has maintained the application of consumer protections for small customers' premises. For customers with life support equipment, de-energisation protections are applied to second settlement points specifically (as well as to the premises as a whole). The Commission considers that this provides appropriate protections while aiming to provide flexibility and choice where it best suits consumers and their needs.

2.3 Introducing more opportunities to separate and use flexible CER would advance the NEO and NERO

The Commission has considered the NEO and NERO, and the issues raised in the rule change request, and has assessed the draft rules against the six assessment criteria outlined in its Directions Paper and below. As noted, Energeia has carried out a cost benefit analysis to evaluate the impacts of the various policy options.

Outcomes for consumers. For consumers who can use and choose to take up more flexible products and services for their CER, we have examined needs and benefits including consideration of:

- What consumers need to use their CER as they intended but also have the confidence for their CER to be used in a way that supports the power system at lower cost. This includes information, appropriate incentives, pricing outcomes and appropriate protections where necessary.
- What changes are necessary so that consumers are appropriately protected when dealing with multiple FRMPs?
- Would the change give consumers a more direct connection to price incentives in a way that allows them to get more value out of their CER?

32 Section 91A of the NEL and section 244 of the NERL.
33 Section 236(2)(b) of the NERL.
34 That is, the legal tests set out on sections 236(1) and (2)(b) of the NERL.

- What benefits might be created for all consumers, including those without CER, such as increased security and reliability, more innovative services, or lower prices and how do they measure against costs?

Technical feasibility and impacts on safety, security, and reliability: To make our decision, we have considered if the rule change would create increased options for flexible demand and ancillary services. Likewise, we have considered if, by enabling resources to be independently treated in market settlements, the rule change will make it more likely for businesses and consumers to use and invest in CER in a way that efficiently promotes system reliability and security.

Principles of market efficiency, in particular, competition: The Commission has considered the overall impacts on market efficiency, with a key focus on if the proposal would create greater retail competition through disaggregating existing energy services and encouraging new energy services.

Increases to innovation and flexibility: We have considered if, over the longer term, the rule change is likely to increase the potential for innovation in services or service types being developed across these markets: retail market – i.e. new offerings for consumers; the wholesale electricity market; ancillary services markets; markets for network services.

Implementation requirements and functions and associated costs: We have carefully considering implementation requirements and the impact of any costs on all parties. We are also considering the interaction of this rule change with other reforms already underway. This is further discussed below.

Emissions reductions: The Commission has considered whether these rule changes are likely to efficiently contribute to achieving government targets for reducing, or that are likely to reduce, Australia's greenhouse gas emissions.

These assessment criteria reflect the key potential impacts – costs and benefits – of the rule change request. Our reasons for choosing these criteria are set out in Rule change consultation paper.[35]

The following section explains how the draft rules would contribute to achieving the NEO and the NERO when assessed against the criteria. The Commission considers that the draft rules would better meet the NEO and NERO than AEMO's proposed rules because the draft rules would provide greater opportunities to optimise the value of CER flexibility by reducing the barriers and costs for consumers to separately identify and manage their CER. For small customers, the arrangements better meet the NEO, NERO and AEMO proposal because they seek to provide arrangements for unlocking greater value and integration of flexible CER for the consumer's CER while considering consumer protections with one retailer as first step. For large customers, the draft rules allow for greater choice of energy service providers and seek to reduce existing barriers and implementation costs by leveraging some existing arrangements used today, which include not introducing new roles and associated responsibilities which is different to AEMO proposal.

2.3.1 The draft rules would deliver long-term benefits for consumers and maintain consumer protections

The draft rules are likely to deliver long-term benefits for consumers in a variety of ways. For consumers looking to participate in arrangements for flexible CER, these rule changes would do this by:

35 See the consultation paper.

- Allowing consumers to have better visibility of their flexible CER by making it easier to separate it from passive loads while also maintaining consumer protection arrangements.
- Making it easier for them to access different network and retail pricing offers for their flexible CER assets based on their individual preferences (separate from their passive load) or to take up direct payments for the use of their assets. For example, tariffs akin to controlled-load assets or a specific service that rewards the responsiveness of CER to market prices or grid conditions.
- For large customers, making it easier to choose different energy service providers to manage their flexible CER.
- Reducing metering costs by allowing consumers to use in-built measurement capability in technology such as batteries and electric vehicle (EV) chargers.

These arrangements would help consumers make choices and have incentives to use their CER at times that are beneficial for the power system (and for the consumer). For example, make it easier for consumers to access the full value stack of opportunities from the wholesale market (once the appropriate mechanism is developed), network services, and other services (e.g. retailer demand response programs combined with a lower tariff and participation in virtual power plants).

For consumers who are not participating in flexible CER arrangements, these rule changes would deliver broader system benefits associated with improved use of the network - translating to fewer costs passed on to all consumers over time. In the long-term, these rule changes will facilitate better integration of flexible CER into the power system to deliver a more reliable and secure energy system that would benefit all consumers.

For organisations such as local councils that manage public assets such as street lights, these rule changes would deliver benefits in the form of reduced energy costs by enabling direct measurement of energy flows in smart street lights. Supporting the uptake of technology like smart streetlights would also have broader consumer benefits, including reducing the length of lighting outages and thereby improving community and road safety.

As noted above, we propose to maintain consumer protections for small and large customers for all proposed arrangements.

2.3.2 The draft rules would facilitate flexibility and innovation

The draft more preferable rules and supporting arrangements are likely to encourage innovative players to offer energy products to the growing cohort of consumers who own or lease flexible CER assets because there would be better visibility of flexible CER load profiles and a reduction in regulatory barriers and costs to participate. Increasing competition for large customers to choose different energy service providers is also likely to promote innovation and flexibility regarding product offerings and services.

Further, the electricity rule change will support innovation in technology with in-built measurement capability. The draft rule has been developed with innovation and flexibility in mind to support and facilitate new technologies to offer in-built metering. The draft rule allows AEMO to determine (and change) meter specifications and meteorology procedures to cater to emerging technologies and use cases. In the future, the Commission anticipates that the proposed arrangements could support innovation of in-built measurement capability in technology such as solar PV, EV charging, and batteries.

2.3.3 The draft rules would promote market efficiency, particularly by increasing competition

The draft rules would enhance market efficiency by supporting competition in the energy retail sector. For small customers, competition is supported by allowing for more choice on products and service offerings for its flexible CER. For large customers, competition is enhanced by allowing choice of energy service providers (i.e. FRMPs) for the customer's flexible and passive loads.

Further, the draft rules reduces barriers and transaction costs to enable:

- Energy service providers to better participate in wholesale energy market scheduling processes. We are considering this issue as part of the AEMC's rule change on integrating price-responsive resources in the NEM.
- Networks to procure demand and export management services more efficiently from these resources, helping to reduce the need for network augmentation.
- An aggregated resource to deliver secure, reliable, and low emissions energy at lower cost.

2.3.4 The draft rules would contribute to system reliability and security

The draft rules are likely to contribute to system reliability by facilitating the integration of flexible CER into the power system. As outlined, the rule changes would make it easier for flexible loads to be metered separately for the purposes of settlement and for these resources to provide wholesale, network, and other services. Further, the draft rules support the provision of an aggregated resource that the market operator (AEMO) could use to deliver secure and reliable energy at a lower cost.

As part of its cost-benefit analysis, Energeia has estimated that a key net benefit unlocked by these rule changes would be increased visibility of subloads (i.e. flexible CER) for networks. With better visibility, networks are better and more accurately able to plan for future infrastructure upgrades, such as network augmentation and the timing of replacement expenditure. This would assist in maintaining the reliability of distribution networks.

In the future, we anticipate that it would also make it easier for flexible CER to participate in scheduled load activities through a mechanism such as the one currently being considered through the Integrating Price Responsive Resources into the NEM rule change.

2.3.5 The draft rules would minimise implementation costs

The Commission has engaged with stakeholders through a variety of forums to identify the nature of costs that would be required to give effect to the proposed arrangements. The draft rules have been developed with the aim of minimising costs for market participants and consumers while providing flexibility and choice for use and management of flexible CER based on consumer preferences. Further information about implementation considerations is at Chapter seven.

In its cost-benefit analysis, Energeia has identified and valued key costs associated with the draft rule changes, including costs related to AEMO system changes, retailer, metering party, and DNSP system changes, and metering and NMI allocation costs. In developing its cost assumptions and estimates, Energeia took into account feedback received from market participants.

Energeia has estimated that these rule changes will lead to $10.4 million in annual system costs[36] and that to balance these system costs, a subset of small and large consumers would need to

36 Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, p. 20.

participate for benefits to outweigh the costs.[37] A summary of this analysis is in Chapter six and detailed in full in Energeia's draft reports.[38]

2.3.6 The draft rules would contribute to emissions reductions

The draft rules would support emissions reductions by supporting energy efficiency of public assets such as street lights (leading to emissions reductions through reduced energy consumption) and thereby helping to achieve the government emissions reduction targets set out in our targets statement. Energeia's cost and benefit analysis has identified that emissions reductions of 267,000 tonnes of CO_2e could be delivered from smart street lighting unlocked by the rule changes,[39] partly offset by potential slight increases in emissions arising from small and large customers using CER to provide network services instead of providing low-emissions energy to the wholesale market.

The rule changes could also contribute to emissions reductions by increasing opportunities for CER to be used for market and grid services. For example, CER can shift 'load' from higher-emissions times of day (EV overnight) to low-emissions times of day when cheap renewable energy is abundant. The rule changes may also make it easier for orchestrated CER to provide low-emissions generation at times of high grid demand, thus potentially displacing fossil-fuel power generation that would have been required otherwise. It should be noted that the emissions reduction impacts of this rule change were deemed negligible, considering the rule change does not directly impact the level of uptake of CER flexibility in the NEM, or how it is applied.[40]

37 Ibid, p. 7.

38 Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024; Measuring Energy Flows from In-Built Technology (Streetlights, EV Chargers, Other Street Furniture) Analysis - Draft Report, 29 Feb 2024.

39 Ibid, p. 21.

40 Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, p. 33.

3 Flexible trading with multiple energy service providers at large customer premises

The Commission has made a draft more preferable rule (draft rule) to introduce flexible trading[41]with multiple energy service providers (or FRMPs) at large customer premises.

This chapter sets out:

- An overview of the proposed draft framework, including key stakeholder feedback, and
- Proposed arrangements that will support the framework, including:
  - market arrangements
  - market functionality (roles and responsibilities)
  - technical requirements, and
  - implementation considerations.

3.1 Overview of the proposed draft framework

3.1.1 AEMO's rule change request proposed a model enabling all consumers to engage multiple energy service providers

In its rule change request, AEMO proposed enabling customers (small and large) to engage multiple FRMPs at a premise under a flexible trading model 2 (FTM2). AEMO's proposed model would enable customers to separate and engage different FRMPs for their flexible and passive loads. AEMO considered this would promote competition for achieving CER benefits (to the consumer and retailer), reduce barriers to entry for new technologies, and promote CER integration.[42]

The Directions Paper noted that we would only progress AEMO's FTM2 proposal for large customers at this time. It also clarified that the Commission would not progress the proposal to enable small customers (residential) to engage multiple FRMPs for a number of reasons; in particular, that it would require a range of changes to market participant and system processes and that the benefits of making these changes would accrue to only some consumers but the costs would be faced by all consumers.[43] During consultation on the Directions Paper, most stakeholders supported the decision to not progress this option.

3.1.2 Key features of the proposed framework

The proposed framework for flexible trading would enable large customers to establish secondary settlement points and engage multiple energy service providers to manage flexible resources at these points. The key features of this framework are:

- It would be voluntary.
- It would enable a large customer to establish secondary settlement points and engage multiple FRMPs at their premises (s3.2.1).
- The relationship between FRMPs would be governed by existing regulatory arrangements and contractual arrangements (s3.2.2).

41 We refer to flexible trading of CER as consumers taking up different product and service offers for their CER. For the industry, it means consumer energy resources and consumption can be more effectively used in the wholesale energy and ancillary services market and for network services.

42 AEMO rule change request, p. 18.

43 Directions Paper, National Electricity Amendment and National Energy Retail Amendment (Unlocking CER benefits through flexible trading), Aug 2023, pp. 32-33.

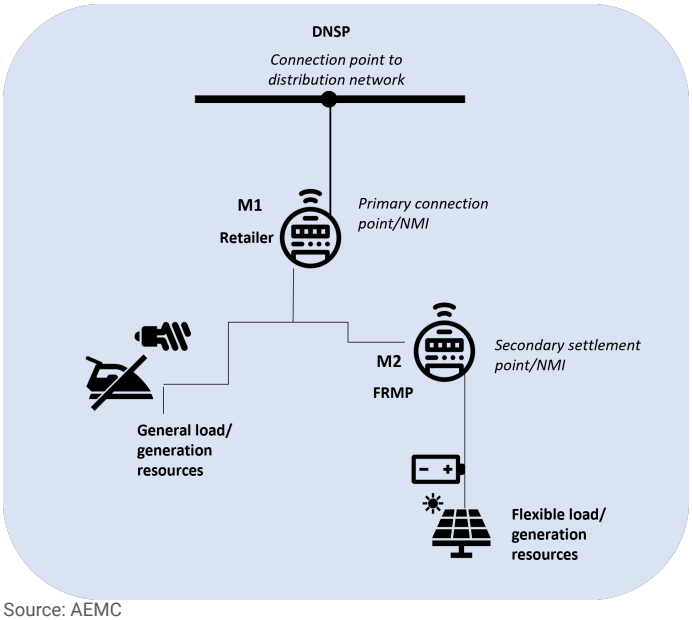
- DNSPs would be responsible for establishing and maintaining secondary NMIs (s 3.3.1)
- It would leverage existing subtractive settlement arrangements to minimise implementation costs

  (s 3.4.1), and
- Distribution network tariffs would be levied to the primary FRMP (s 3.3.3).

The key components of and parties who would participate in this framework are captured in Figure 3.1.

These arrangements will contribute to the NEO and NERO by delivering benefits to these consumers, promoting competition in the retail energy sector, enhancing innovation in energy products and service offerings for flexible CER, and can contribute to system reliability and security by facilitating the integration of flexible CER into the power system. Further details about how these rule changes contribute to the NEO and NERO are outlined in Chapter two.

Figure 3.1: Flexible trading with multiple energy service providers at large customer premises



Source: AEMC

3.1.3 Stakeholders feedback on proposed arrangements for large customers to choose multiple energy service providers

During consultation, some stakeholders[44] expressed support for a flexible trading framework for large customers and considered that there are some benefits to introducing new arrangements, but noted that the Commission should carefully consider the supporting technical arrangements.

Stakeholders who expressed concern about the proposed arrangements noted that customers can obtain value from their CER through a single retailer and that customers can already engage multiple FRMPs through the small generation aggregator (SGA) (soon to be known as small resource aggregator (SRA)) and embedded network frameworks.[45] Some retailers also noted that the proposed framework would expose them to wholesale market risk and undermine their

44 PIAC, AEMO, Clean Energy Council, Flow Power, Enel-X, Alinta, Citipower & Powercor Australia & United Energy (CP&PA&UE).

45 Submissions to Directions Paper: SA Power Networks, p.2 Shell Energy, p.3; Origin, p.1; AGL, p. 3; Red Energy & Lumo Energy, pp. 4-5

hedging (particularly if switching assets between settlement points was allowed), and would require costly upgrades to billing, forecasting, and settlement systems.[46]

Some networks also noted that proposed flexible trading arrangements should not affect the ability for DNSPs to manage DOE's[47]or hinder the ability of CER devices to respond to DOEs and dynamic pricing signals.[48]

One stakeholder advocated for the flexible trading model to be explored for small customers as well, in the interests of increasing choice for residential consumers.[49] As noted in the Directions Paper, the Commission considers that there may be an opportunity to progress a trial of AEMO's FTM2 model for small consumers via the industry sandboxing arrangements.

The Directions Paper sought feedback on the continued use of the embedded network framework for large customers to engage multiple FRMPs. Some stakeholders, including large retailers and some DNSPs queried why the ongoing existing approach of using the embedded networks model was not suitable for large customers and advocated for this option to remain open to customers and FRMPs.[50]

Other stakeholders opposed the use of the existing embedded network framework to allow customers to engage multiple FRMPs. They noted that the embedded network framework was not intended to be used for flexible trading, there is often no visibility of the child point(s), and the framework proposed by the Commission differs from the embedded network framework as there will be a single FRMP at both the 'parent' and 'child' NMIs.[51]

The Commission has considered the stakeholder feedback in developing the proposed supporting arrangements. These are outlined below, and we welcome stakeholder feedback in relation to these arrangements.

3.1.4 The draft framework provides a good alternative to establishing two connection points to the distribution network

The Commission considers that the draft framework provides a more accessible and efficient option for obtaining a second NMI and engaging a second FRMP compared to establishing a second connection point to the distribution network - noting that this option would still exist. As we noted in the Directions Paper, the process to establish two points can be costly and time-consuming, and customers face a network charge for each point.[52]

While there are existing avenues for large customers to engage multiple FRMPs, we consider that the draft framework would, as noted above, be more appropriate and enduring and:

- enable customers to gain more value from their flexible CER through increased choice of energy service providers and their products and services
- lower the barriers to entry for multiple FRMPs to provide energy services at a premises and thereby promote innovation and competition, and
- have minimal implementation costs. The draft framework replicates existing system arrangements to minimise system costs.

46 Submission to Directions Paper: Shell Energy pp. 2-3; Red Energy & Lumo Energy, p.4.
47 Submissions to Directions Paper: CP&PA&UE, p.1; SA Power Networks, p.2.
48 Submission to Directions Paper: Joint NSW DNSP Response, pp. 5-6.
49 Submission to Directions Paper: PIAC, pp.3-4.
50 Submissions to Directions Paper: Shell Energy, p. 3; Energy Australia, p.4; AGL, p.3; Origin, p.2; AEC, p. 1.
51 Submissions to Directions Paper: Flow Power, p. 3; Enel-X, p. 7.
52 Directions Paper, Aug 2023, pp. 26-28.

3.1.5 These arrangements would deliver benefits to consumers and the system more broadly and contribute to the NEO and NERO

This section and next section outlines Energeia's cost-benefit analysis, and the arrangements that will support the proposed new meter types, taking into account stakeholder feedback.

Energeia's analysis of this rule change indicates that this rule change would deliver benefits to large customers and consumers broadly. Energeia found that this rule change will provide the same or similar benefits as the existing use of the embedded network framework to allow multiple FRMP but at a lower cost.[53]

Additionally, we consider that it is plausible that providing networks access to secondary settlement point data may lead to more network services agreements for demand management, providing a direct benefit to the owner of the CER, and avoiding long-term network expenditure thereby reducing network costs to all customers.

Energeia's estimated the costs for proposed changes, particularly for changes to AEMO market systems, market participants and DNSPs. The findings of the benefits and costs are outlined in detail in Chapter six.

As noted in Chapter two, the Commission considers that the proposed draft rules better advance the NEO and NERO by providing large businesses greater opportunities to choose different energy service providers (ie. retailers, aggregators, and SGAs) for their CER resources and have those resources participate in the market. This seeks to increase competition and promote innovation in the products and services that are offered to businesses. The proposed arrangements also provide the opportunity for market participants to offer network services where required by network businesses.

3.2 We are proposing a range of market arrangements to support flexible trading with multiple energy service providers

This section outlines the proposed market arrangements that would support this framework including:

- eligibility requirements
- proposed arrangements between FRMPs
- whether assets can switch between the primary and secondary settlement points, and
- the interaction between the draft framework and the embedded network framework.

3.2.1 The framework would have minimal eligibility requirements

In its rule change request, AEMO proposed specifying the type of resources that could be connected to secondary NMIs, noting that "Clear specification should be provided around the types of resources that can, or cannot, be connected within its proposed private metering arrangement (PMA). For example, resources connected to a PMA should be controllable, whereas electrical wiring and equipment that is required on-demand, such as life support equipment, should not be connected via a PMA."[54]

The draft rules provide the following eligibility requirements that would apply for large customers to establish secondary NMIs and have multiple FRMPs.

For a customer to have secondary NMIs:

53 Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, pp. 32-33.

54 AEMO rule change request, p. 10.

- There must be only one customer at the connection point. This differs from the embedded network framework, where several customers may be connected to child connection points behind a single parent connection point. A business customer with several connection points may choose to aggregate their load across the different connection points to meet the threshold of a large customer in order to participate in flexible trading. That is, a business customer who meets the threshold could then engage multiple energy service providers and establish secondary settlement points(s) at these connection points.
- The secondary NMI needs to be established downstream of a transmission or distribution network connection point.

These requirements would be provided as amendments to chapters 2, 7 and 10 of the NER (see draft rules Ch 2 (2.3.4), Ch 7 (7.2.6), and Ch 10- definitions of market connection point, secondary settlement point).

For a large customer to engage multiple FRMPs at one premises:

- The customer must meet the definition of a large customer as per the NERL or jurisdictional legislation. Under the NERL, a larger customer is a business customer that consumes above the upper consumption thresholds defined in the NERL regulation as 100MWh per year. [NERL section 5(3) and National Energy Retail Regulations section 7 (b)].
  - The possibility of a large customer falling below the consumption threshold for a large customer (as to become a small customer) would be managed through a new clause 2.3.2 in the NER.
- The secondary FRMP must be registered as a Customer or an Integrated Resource Provider (in its capacity as a Market Customer or an SGA and must classify the secondary settlement point as one of its market connection points.[55]

These requirements would be provided as amendments to chapters 2 and 10 of the NER (see draft rules, Chapter 2 - s2.1B.1, s2.1B.2, 2.2.2, 2.2.8, 2.3.2; Chapter 10 - definitions for scheduled generating unit, scheduled bidirectional unit or scheduled network service).

Existing roles and responsibilities of FRMPs provided in the NER and NERR would apply to secondary FRMPs. For example, the requirement for FRMPs to obtain retailer authorisation would apply to secondary FRMPs (e.g. where secondary FRMPs are on-selling energy to the customer).[56]

3.2.2 The relationship between FRMPs would be governed by existing regulatory arrangements and contractual arrangements

To ensure that the arrangements are as efficient and low cost as possible, the Commission has determined that the draft rules would not require a contractual relationship between primary and secondary FRMPs participating in the flexible trading framework. As a flow on from this, the Commission does not consider that formal notification requirements are needed between primary and secondary FRMPs and that if either FRMP requires access to particular information, it could be acquired from the customer.

Further, roles and responsibilities of FRMPs and the relationship between FRMPs would be governed by existing arrangements in the NER, NERR and NERL and by contractual arrangements between the customer and FRMPs. The Commission has detailed a number of scenarios below where interaction between FRMPs may arise and existing arrangements would apply.

55 An SGA can only classify the secondary settlement point if it is a small resource secondary settlement point, which only applies where the metering installation that comprises the secondary settlement point is for one or more small generating units or small bidirectional units (i.e. units exempt from registration) and the only supply to the secondary settlement point is for use by the small bidirectional unit or auxiliary load of the unit.

56 Section 88, National Energy Retail Law.

Disconnection for non-payment

If the primary retailer disconnects, existing arrangements for large customer disconnections would apply. In a scenario where there is a second settlement point behind the primary connection point and the primary connection point is disconnected, the customer would also lose supply at the secondary NMI and de-energisation would occur at both points. Similarly, the existing approach to re-energisation would apply, in that each retailer must apply for re-energisation (that is, the secondary settlement point would not automatically be re-energised when the primary connection point is re-energised). As noted above, obligations to notify about disconnection could be included in contractual arrangements between the customer and FRMPs.

For the purposes of settlement, AEMO metrology procedures would specify that when metering data providers (MDPs) 'flag' to AEMO when there is a disconnection or network outage at the connection point, AEMO can then use that flag when processing the metering data for the secondary settlement points (and revert the value to zero). This will then flow through to existing arrangements for settlement under Chapter 3 of the NER.

The Commission considers that retailers at primary connection points and the customer (and therefore secondary FRMP) would be able to agree terms relating to the treatment of any energy flows at times of a supply outage on the network without the assistance of additional market processes. This approach acknowledges that large customers have unique arrangements and complex contractual arrangements governing matters with and between their retailers.

These requirements would be provided as amendments to Div 5 of the NERR (s104, 106A, s111, s113, 116, 119).

Failure of the primary or secondary FRMP

If the primary or secondary retailer fails, the existing retailer of last resort (ROLR) provisions would apply. That is, the previous retail contracts are replaced with a new arrangement with the relevant designated retailer of last resort. In the event that the secondary FRMP who is a non-retailer fails, metering data would no longer be provided from the secondary NMI and the primary FRMP would become responsible for the entire energy flow at the premises. The Commission considers that arrangements for this event could be managed by contract between the customer and FRMPs if needed. This approach acknowledges that large customers have unique arrangements and complex contractual arrangements governing matters with and between their retailers.

Dispute resolution arrangements

Dispute resolution between FRMPs would be governed by the existing dispute resolution process set out in Chapter 8 of the NER. The Commission has not identified a need to develop particular arrangements for the flexible trading framework and considers that the existing processes are adequate.

3.2.3 Switching of assets across FRMPs

AEMO's rule change request proposed that their flexible trading model should enable the customers or their FRMPs to switch their "controllable" resources across different FRMPs to enable the customer to conduct arbitrage.[57]

During consultation, several stakeholders expressed concerns about enabling customers or their agents to switch customers' resources between secondary and primary FRMPs. Some retailers

57 AEMO rule change request, p. 5

suggested that it would expose them to wholesale market risk and undermine their hedging.[58] Further that exposes FRMPs to significant risks of load being shifted to or from the secondary connection/settlement point without warning, and potentially in conflict with market signals.[59]

Some DNSPs noted potential safety risks related to wiring between potentially large assets. The joint submission from Citipower, Powercor, and United Energy considered that switching of resources "risks back-feed and safety risks associated with alternative points of supply. Such designs need to be consistent with AS3000, the relevant jurisdictional Service and Installation Rules, and should involve consultation with jurisdictional Electrical Safety Regulators."[60]

The Commission notes that there are risks to primary retailers posed by switching of resources between the primary and secondary NMIs. Switching could undermine the hedging positions of retailers and, thereby, their ability to offer customers hedged products. We also note some jurisdictions impose restrictions on switching between points in service installation rules, and that customers and FRMPs will take these rules into account when choosing arrangements that best suit their business model.

Given this, the Commission considers that the choice to switch and any risks posed by customer switching could be managed by contractual arrangements between the customer and FRMPs, and we do not propose to regulate this activity in the NER.

3.2.4 Interaction with the embedded network framework and retail and network exemption guidelines

Large customers and FRMPs currently using embedded networks would not need to switch

The draft rules would not require large customers currently using embedded networks to switch to the flexible trading framework. However, the Commission notes that for large customers who are not on-selling energy, the draft flexible trading framework is intended to be a more appropriate and efficient mechanism to engage multiple FRMPs and establish secondary settlement points. Customers with SGAs using embedded networks may wish to convert to the new framework where there is no other reason to be regulated as an embedded network. The Commission considers that it would be preferable for new entrants looking to use SGAs to adopt the draft flexible trading framework with secondary settlement arrangements, rather than establishing an embedded network.

Interaction with the Network Exemption Guidelines

The Commission has considered how the proposed arrangements would interact with the AER Network Exemption Guidelines to minimise barriers and transaction costs for large customers looking to take up the draft flexible trading framework.

The AER Network Exemption Guidelines take a broad view of what constitutes a transmission or distribution system but then allows for a range of deemed and registrable exemptions. The Commission notes the scope for duplication if metering installations used as secondary settlement points are also subject to exemption conditions under the Network Exemption Guidelines. We intend to work with the AER, in the course of preparing the final rule, to consider possible measures to streamline and clarify any interaction between the two frameworks.

In relation to existing embedded networks, these would remain embedded networks even if a secondary settlement point is established on the premises. For example, at a large customer premises, there may be a second customer connected within the site boundaries, buying from its

58 Submission to Directions Paper: Shell Energy, pp. 2-3.
59 Submissions to the Directions Paper: Red Energy & Lumo Energy, pp. 4-5; Shell Energy, pp. 2-3; CP & PC & UE, p. 4.
60 Submission to Directions Paper: CP & PC & UE, p. 4.

own retailer through a parent/child metering arrangement. The first or second customer (or both) could establish its own secondary settlement point (e.g. for its controllable load) and the embedded network would continue to operate.

3.3 Market participants roles and responsibilities (market functionality)

This section outlines the market roles and responsibilities that would support the draft framework, including:

- DNSPs responsibility for the establishment and maintenance of secondary NMIs
- DNSPs visibility of standing data from secondary NMIs, and
- allocation of distribution network tariffs to the primary FRMP.

3.3.1 DNSPs would be responsible for establishing and maintaining secondary NMIs

In its rule change proposal, AEMO proposed creating a new role of 'NMI service provider' equivalent to the embedded network manager role. The NMI service provider would be responsible for establishing secondary NMIs. Under the embedded network framework, the embedded network manager performs market interface functions such as establishing a NMI and recording site information. AEMO proposed that the NMI service provider be responsible for the creation of NMIs away from the network connection points.[61]

The Commission has determined that the role of establishing and maintaining NMIs should sit with the DNSPs, consistent with arrangements for establishing and maintaining NMIs at the primary connection point. The Commission's draft rule provides that these responsibilities and processes would extend to secondary settlement points. These responsibilities include:

- creating a NMI for a secondary settlement point at small customer premises (at the request of the customer or the customer's retailer)
- linking the NMI at the secondary settlement point to the NMI at the primary connection point (that identifies the main metering installation at the premises), and
- maintaining NMI standing data at secondary settlement points.

The same arrangements would apply for small customer premises (see Ch. 4, s 1.2.2).

The Commission has considered other options, including this role being assigned to other participants such as secondary FRMPs, metering parties, or a newly created NMI service provider role.

The Commission considers that assigning this role to DNSPs is preferable because it:

- aligns with the current role of the DNSPs of establishing and maintaining NMIs
- would eliminate the need for creating a new role and relying on new businesses to enter the market to provide this service
- aligns with feedback from stakeholders that DNSPs would be able to create NMIs beyond their connection points, and
- aligns with the Commission's decision to provide DNSPs with visibility of secondary NMIs and access to secondary NMI data.

The Commission notes that this position was canvassed with stakeholders post-submissions and no stakeholders expressed opposition. These arrangements would be provided for in amendments to Ch 7 (7.2.6) and amendments to defined terms that 7.8.2(d)(1) applies.

61 AEMO rule change request, p. 9.

3.3.2 Visibility of secondary NMIs to DNSPs

The rule change request from AEMO did not directly address whether DNSPs should have visibility of or access to data from the secondary meter.

In submissions to the Directions Paper, several DNSPs advocated for the need for DNSPs to have visibility of secondary NMIs and to access data from secondary meters to support network management activities.[62] For example, Citipower, Powercor and United Energy noted: "there is a risk that there will be a large amount of aggregated load or exports being controlled by third parties which are invisible to the distribution networks. This will have perverse impacts on efficient network planning including system security and emerging minimum demand challenges."[63]

DNSPs could access secondary NMI metering data

Noting stakeholder feedback and broader CER integration considerations, the Commission considers that DNSPs should have access to secondary NMI metering data (that is, energy flow data). We propose that rules provide DNSPs with the right, but not the obligation, to access metering data from secondary NMIs. Stakeholder feedback post-submissions indicates that providing DNSPs with access to this data would involve minimal costs for relevant market participants (DNSPs, metering parties, energy service providers, AEMO).

The Commission notes that access to additional types of data, such as power quality data, has been considered through processes such as the AEMC's Review of the Regulatory Framework for Metering Services and that these will be considered as part of the AEMC's Accelerating smart meter deployment rule change.

We consider that DNSP access to metering data would enhance their visibility of CER and offer potential benefits including:

- improved network operation and forecasting
- easier procurement of network support services from CER, and
- enabling the development of targeted network tariffs for flexible trading customers.

The Commission has proposed minor amendments to Chapter 7 of the NER (7.15.5(c)(7)) to enable DNSPs to access energy flow data from secondary NMIs. These amendments would be supported by changes to AEMO procedures.

3.3.3 Distribution network tariffs

AEMO's rule change proposed that network tariffs should only apply to the primary FRMP. That is, the regulatory framework would not provide for separate tariffs to be issued to a customer for their primary and secondary NMIs. AEMO noted that the network tariffs would be levied to the same customer even if they were separately applied to the primary and secondary FRMP.[64]

Some stakeholders noted risks associated levying all network tariffs for the customer to the primary FRMP. Large retailers expressed opposition noting:

- The proposal places the risk on the primary FRMP, including impacts on billing systems.
- Secondary FRMPs may increase customer bills and drive network expenditure.[65]

62 Submissions to Directions Paper: Joint NSW DNSP Response, p. 6; CP & UP & PC, p. 1.
63 Submission to Directions Paper: CP & PC & UE, p.1.
64 AEMO rule change request, p. 10-11.
65 Submission to Directions Paper: Shell Energy, p.3.

The AER also noted this a blunt price signal at the primary NMI and may not yield an efficient price response from the customer.[66] DNSPs noted that DNSPs can and some do already offer different tariffs for flexible loads if they choose to and, but that mandating splitting network tariffs across FRMPs would require costly and time-consuming billing system upgrades for DNSPs.[67] Smaller retailers such as Enel-X expressed support for the network tariff being levied to the primary FRMP.[68]

The Commission has considered stakeholder feedback and implementation considerations and determined that DNSPs should not be required, as part of this rule change, to develop and levy separate network tariffs for primary and secondary FRMPs/NMIs.

Key reasons for this decision are:

- This approach is consistent with the current NER as to who constitutes a network customer. Requiring different network tariffs to be levied at primary and secondary NMIs would require wholesale changes to the pricing arrangements and this decision would extend beyond the scope of this rule change.
- DNSPs have flexibility under the NER to develop targeted tariffs, including at secondary points. During the consultation process, several DNSPs expressed an interest in developing more targeted tariffs. The Commission supports DNSP efforts to develop and apply tariffs that would promote efficient outcomes under the draft flexible trading framework arrangements.
- Splitting network tariffs across FRMPs could require costly and time-consuming billing system upgrades for DNSPs and mandating these upgrades to support the proposed flexible trading framework alone would be inefficient. The Commission considers that this change should be considered as part of other processes, such as the AEMC's proposed review into the role of network and retail pricing as noted in Chapter one.

These arrangements would be provided for through amendments to Chapter 6 of the NER (s6B.A2.1 and s6B.A2.2).

The Commission notes that this arrangement would not prevent the primary FRMP from passing on a portion of the network tariff to the secondary FRMP, via the customer. For example, if the relevant DNSP issues different tariffs for the primary and secondary points, the primary FRMP may choose to pass on the 'secondary tariff'. However, we have determined that there should not be requirements or restrictions on a primary FRMP passing on network tariffs to a secondary FRMP. That is, this decision should be dealt with between the customer and the primary and secondary FRMPs through their contractual arrangements.

The Commission also notes that we expect secondary FRMPs would be incentivised to optimise the operation of flexible assets at the secondary settlement point in a manner that would minimise the customer's network tariffs. Further, we consider that large customers would have access to the data, the skills and resources to identify if a secondary FRMP's operations are leading to increases in their network charges.

3.4 There are supporting technical requirements

This section outlines the technical requirements that would support the draft framework, including:

- subtractive settlement arrangements

66 Submission to Directions Paper: AER, p. 12
67 Views expressed at online workshop with ENA and members, 15 Nov 2023.
68 Submissions to Directions Paper: Enel-X, p.5; Flow power, p. 3.

- application of existing metering requirements under chapter 7 of the NER
- treatment of settlement anomalies
- procedures relating to inactivate secondary NMIs, and
- implementation of dynamic operating envelopes (DOEs).

3.4.1 Settlement and metering arrangements

The Commission proposes to leverage existing settlement arrangements and apply subtractive settlement arrangements

As noted above, AEMO's rule change request proposed the concept of private metering arrangements for supporting flexible trading arrangements. A PMA would enable a NMI to be established within an end user's electrical installation and for an additional meter to be installed down-stream of an existing meter supporting subtractive settlement arrangements. AEMO noted that the secondary meter could be installed without the involvement of the DNSP and that the settlement process already caters for subtractive settlements.[69]

In its proposal, AEMO also noted that current metering requirements would create barriers to the establishment of secondary settlement points, due to the size of meters required under the NER increasing the complexity and cost of installation. To address this, the rule change request also proposed establishing a new category of minor energy flow meter in the rules that could be used at secondary settlement points.

The Commission received relatively little feedback on the proposed settlement arrangements in submissions. However, stakeholders provided additional feedback through the public forums and working groups following closure of submissions. Retailers and AEMO noted that this arrangement aligns with existing approaches and would mean reasonably minimal changes to systems from a billing and settlement perspective. DNSPs noted that DNSP billing systems are not currently set up to levy separate network charges for primary and secondary NMIs using subtractive metering arrangements and if DNSPs did want to do this in the future, it would require costly upgrades to billing systems.[70] The Commission recognises that these changes would be required in order for DNSPs to offer different charges for secondary settlement points. The Commission will consider how network tariffs are currently operating and could be applied in context of the NEM transition and uptake of flexible CER through its proposed review of the role of network and retail pricing.

The draft rules provide that subtractive settlement arrangements would apply between the primary connection point and secondary settlement point(s) at large customer premises. This would minimise the need for upgrade to systems currently used by market participants and AEMO. This approach also reflects well-established arrangements used by market participants under the embedded network framework, thereby reducing transaction and system change costs. DNSP billing would remain unaffected by the approach in the draft rules, as they would continue to bill the retailer at the primary connection point based on total usage at the premises. These arrangements would be provided for in amendments to AEMO procedures.

The Commission notes that we considered alternative approaches and do not propose to introduce other metering arrangements for settlement, such as multi-element or parallel metering, for reasons outlined below:

69 AEMO rule change request, p.8.

70 Views expressed at online workshop with ENA and members, 15 Nov 2023.

- Using multi-element metering for settlement would have substantial impacts on AEMO and retailer systems handling metering data and settlement and would be inconsistent with the current metering roles and responsibilities (i.e. which FRMP would be responsible for metering at the site).
- Parallel metering arrangements do not align with AEMO or retailer systems and this change would result in significant and costly changes to AEMO and retailer billing systems.

New meter type 9 could be used at primary connection point and secondary settlement point at large customer premises

The draft rules provide that large customers could use the new meter type 9 at the primary connection point and secondary settlement point.[71] This would enable large customers to use technology with in-built measurement capability at these points, such as EV chargers. The main benefits for large customers associated with this change would be reduced metering costs (it would avoid the need to install a separate meter alongside the technology). Customers could still choose to use a type 4 meter at these points if they prefer. The arrangements for the proposed meter type 9 are described in detail at Chapter five.

AEMO procedures would address issues related to settlement anomalies

AEMO's rule change request noted concerns about settlement anomalies and gaming issues. AEMO highlighted that settlement anomalies can occur during periods of system outages, where energy flows in customer electrical installations providing back-up supply are incorrectly recorded as on-market energy flows.[72] AEMO also raised concerns about participants retrospectively changing their market participation status to "game" the market i.e. showing themselves as generating during high price events.[73]

Settlement anomalies would be addressed through AEMO procedures

In its rule change request, AEMO noted that periods of power outages coupled with back-up power flows may lead to settlement anomalies under subtractive settlement arrangements. This scenario may lead to off market power flows within an electrical installation or embedded network to be incorrectly settled in the market. Additionally, retrospective activation of NMIs as described by AEMO may lead to gaming of the market. AEMO has advised that this issue currently occurs under embedded network arrangements and could occur under proposed arrangements for flexible trading.

The Commission agrees with AEMO's analysis of this issue and supports its view that changes to procedures can address this issue. For example, AEMO procedures could prohibit retrospective NMI activation and deactivation for the purposes of flexible trading.

Arrangements when the secondary NMI becomes inactive

The draft rules and AEMO procedures would determine arrangements for when secondary NMIs become inactive. Where appropriate, these leverage existing arrangements used under the embedded network framework.

Secondary FRMPs could choose to cease being a FRMP by declaring the NMI to be inactive

AEMO procedures would provide that where a secondary FRMP chooses to cease being a FRMP by declaring the NMI to be inactive, the inactive NMI would automatically revert to the primary

71 see Appendix E, Summary of draft rules, s3.6.
72 AEMO Rule change request, p. 25-27
73 Submission to Directions Paper: AEMO, pp. 4-8.

FRMP. As per existing arrangements for inactive NMIs, data would still be collected and all metering roles would stay in place, but would not be "turned on." If the customer doesn't use the secondary settlement point/NMI, the roles remains inactive. If the customer opts back in, the metering roles become active again. This approach is well understood and used under the embedded network framework.

These requirements would be provided in AEMO procedures and in amendments to Chapter 2 of the NER (see draft rules, Ch 2- s2.10.1) and in AEMO procedures.

Onus on the second FRMP to deactivate NMI where a large customer changes status to a small customer

Some stakeholders noted that there are situations where large customers fall below the threshold for this status and need to be classified as small customers. If the large customer was using the draft framework for flexible trading and its status changed to a small customer, the draft rules and AEMO procedures would provide that the onus is on the secondary FRMP to deactivate the NMI at the secondary settlement point. This approach would reduce burden on AEMO and metering service providers and allocate the responsibility to the party with an existing contractual relationship with the customer.

These requirements would be provided as amendments to chapter 2 of the NER (see draft rules, Ch 2- s2.3.2) and in AEMO procedures.

Implementation of dynamic operating envelopes (DOEs)

During consultation, some DNSPs noted that proposed flexible trading arrangements should not affect the ability for DNSPs to ensure that there is accountability for DOE compliance at a site and should not conflict with existing arrangements whereby DNSPs manage flows at connection points (versus secondary points). [74] NSW DNSPs also noted that arrangements should not hinder the ability of CER devices to respond to DOEs and dynamic pricing signals.[75] During workshop discussions, DNSPs also noted that issuing DOEs to a second FRMP or at the asset level versus connection point level, would be complex and costly.

Noting this stakeholder feedback, the Commission does not propose to alter arrangements in relation to DOEs. That is, DNSPs would continue to issue DOEs to a primary connection point(s) at a large customer premises that has adopted the flexible trading framework. 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). The Commission also notes that more broad issues regarding pricing and the operation of dynamic operating envelopes are being considered through processes such as the AER's review of Flexible Export Limits[76]and the AEMC's proposed review of the role of network and retail pricing.

3.5 Implementation considerations

As noted throughout this chapter, a range of changes will be required to implement the framework in the draft rules. Key changes required to implement this draft framework include:

- Updates to AEMO's MSATS system, primarily related to the proposed secondary NMIs.

74 Submissions to Directions Paper: CP & PA & UE, p.1; SA Power Networks, p.2.

75 Submission to Directions Paper: Joint NSW DNSP Response, pp. 5-6.

76 Refer to the AER's guidance on export limits

- Changes to retailer billing systems to account for the existence of secondary settlement points.
- Updates to DNSP systems to enable establishment and maintenance of secondary NMIs.
- Updates to AEMO procedures, primarily MSATS Procedures, Metrology Procedures, and Service Level Procedures, and
- Updates to AER guidelines related to embedded network arrangements, including the Network Exemption Guidelines and Retail Exemption Guidelines.

See further information about implementation considerations at Chapter seven. The costs associated with changes that would have the greatest impact are detailed in Chapter six and in Energeia's draft report.[77]

77 Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024.

4 Opportunities to optimise CER flexibility for small customers

This chapter outlines the Commission's draft determination and more preferable draft rules to introduce arrangements that enable small customers and their agents (i.e. retailers and aggregators) to identify and manage flexible CER separate from inflexible or passive energy use; and for that flexible CER to be better recognised in the energy market.

It sets out:

- An overview of the proposed arrangements, including key stakeholder feedback.
- Proposed arrangements that will support the framework, including:
  - market arrangements
  - market functionality (roles and responsibilities)
  - technical requirements, and
  - implementation considerations
- Options that the Commission has determined not to progress further.

4.1 Overview of the proposed framework

Households are taking up CER at an accelerated rate[78] as CER offers consumers the opportunity to have lower energy bills and a greater level of control over their energy use. If CER is optimised and integrated, it can help to manage network infrastructure and balance fluctuations in energy demand and supply. Integration has the potential to deliver positive outcomes such as cost-efficiency and reliability for all consumers, including those who do not have access to CER technology.

Currently, the meter at the primary connection point at residential premises (e.g. a smart meter) meters energy data for both non-flexible and flexible loads. As noted in the Directions Paper, the Commission sees there are opportunities to improve how flexible CER is separately identified and managed (i.e. how consumers or their energy service providers (retailers or aggregators) use and interact with CER) in the market.

Following stakeholder consultation and analysis of alternatives against our assessment criteria, the Commission has developed draft rules for small customers to provide that:

- Small customers would be able to choose to establish a secondary settlement point without a separate connection to the distribution network for their flexible CER, and have a National Metering Identifier (NMI).[79]
- For secondary settlement point/s, flexible CER energy consumption would be separately metered through either a smart meter (type 4 meter) or another form of settlement-grade meter built into the CER device or wired externally to the device. The latter represents a change to the existing framework. We established this new meter as a type 8 meter.[80]

78 AEMO's Draft 2024 Integrated System Plan estimates, under the Step Change scenario, that half of all detached homes in the NEM will have rooftop solar by 2034, growing to a ratio of four out of five homes by 2050. Source: AEMO, Draft 2024 Integrated System Plan for the National Electricity Market, p.47.

79 A metering installation at the end user's premises, where energy data is metered by a smart meter or (type 4) or a type 8 meter, a new meter for small customer premises.

80 The volume limit of a type 8 meter is 750 MWh per year at the connection point, with an accuracy of ±2%. A full description of type 8 meters is provided in Chapter five, Section 5.2.1. A new row for type 8 meter is added in Table S.7.4.3.1 of the proposed rule.

The new arrangements would be voluntary and based on consumer choice. A combination of different options is likely to be employed in the market, and the regulatory frameworks should provide flexibility for customers and market participants to use the most efficient solution for the relevant circumstances.

Different CER technologies and business models are also likely to need different configurations to measure and manage responsive CER. Further, given the speed of technological development and the increasing use of smart appliances, it is important that the Rules are robust for the long term and will enable innovation and choice.

Notwithstanding the importance of flexibility for business models, the Commission has determined not to make any rule changes in relation to non-market devices for CER measurements (black boxes) or two connection points with the distribution network. The reasons why we did not proceed with those options are set out in Section 4.2.5.

Furthermore, the supporting arrangements have considered complementary changes to the NERR, including maintaining a number of consumer protections (inclusive of disconnections and life support) for this new proposed arrangement. Further detail is provided below.

We note that there will be a need to consider changes or revisions to the supporting guidance and guidelines from the AER, in particular, information about products and services for these second settlement points. We also note that the AER has recently completed its Review of consumer protections for future energy services. This work is now being considered by officials as part of the broader CER work program. We will consider any updates and feedback from this work for our final determination.

4.1.1 Stakeholders recognised the benefits of separately identifying CER, but views differed on implementation

In their submissions to the Directions Paper, the majority of stakeholders supported the concept of separately identifying and integrating CER to unlock its value for consumers and the market. However, stakeholder views differed on the particular configuration model with which CER is separately identified.

Enel X,[81] Energy Locals,[82] PIAC,[83] Intellihub,[84] and Master Electricians[85]supported the establishment of a second settlement point and sub-metering, seeing those as tools to encourage innovation and increase consumer choice.

- In their submission, PIAC maintained that "retailers currently have little financial incentive to optimise and coordinate CER...Enabling extra settlement points addresses this issue by lowering barriers for specialised CER aggregators to operate in the energy market and incentivising retailers to either develop competing offerings or partner with these providers on a more equal basis."[86]
- Master Electricians Australia encouraged the change to secondary settlement points, maintaining that without them "the retailer sector will continue to resist change, and stifle the implementation of CER reforms".[87]

81 Submission to the Directions Paper: Enel X, p.1, p.4.
82 Energy Locals, p.2, p.4.
83 PIAC, p.2.
84 Intellihub, pp.2-3.
85 Master Electricians Australia, pp. 10-11.
86 PIAC, p.2.
87 Master Electricians Australia, p.10.

However, some large retailers, the Australian Energy Council (AEC), Energy Users Association of Australia (EUAA), and Tesla did not support the rule change with respect to small customers, mainly due to not seeing the merits of establishing a secondary settlement point.[88]

- The AEC stated that concerns about lack of CER visibility are overstated, and benefits from separately identifying CER will only be incremental to the existing business models focussed on CER.[89] A similar point was raised by Tesla, stating that no barriers to CER orchestration stem from the inability to separately identify CER.[90]
- The EUAA stated that a different price point for the CER, the main advantage of separate identification of CER for settlement, can already be achieved today without any regulatory change.[91]
- Some retailers were concerned about added complexity and costs for consumers (AEC, Energy Australia, Clean Energy Council (CEC), Momentum Energy, and Tesla.[92] The AER,[93] although not opposing the rule change, showed concerns for costs associated with wiring arrangements and administrative processes that would support secondary settlement points.

Some distribution networks (Energy Queensland, AusNet, and TasNetworks) were neutral to the introduction of secondary settlement points[94] (except for SA Power Networks, recognising opportunities)[95] and warned that implementation costs and considerations may outweigh their benefits. In particular, Joint NSW DNSPs noted that implementation costs would need to be incurred to ensure secondary settlement points support network operations (e.g. the ability to send dynamic operating envelope instructions and dynamic pricing).[96]

4.1.2 These arrangements would deliver benefits to consumers and the system more broadly and contribute to the NEO and NERO

Energeia's analysis of these draft rule changes found that the proposed changes for small customers would deliver benefits to consumers who participate in CER flexibility and to consumers more broadly. In summary, Energeia found that the rule would be beneficial for a small customer battery, as long as the device is being used for providing network services. Energeia found that this rule change will provide the same or similar benefits to the existing use of retailer-led virtual power plants (VPP), but at a lower cost where the VPP is providing network services for demand management.[97]

Additionally, we consider that it is plausible that providing networks with secondary settlement point data may lead to more network services agreements for demand management, providing a direct benefit to the owner of the CER, and avoiding long-term network expenditure thereby reducing network costs to all customers.

Energeia's estimated the costs for proposed changes, particularly for changes to AEMO marketsystems, market participants and DNSPs. The findings of the benefits and costs are outlined indetail in Chapter six.

88 AEC, p.2; EUAA, p.2; Tesla, p.3.
89 AEC, p.2.
90 Tesla, p.3.
91 EUAA, p.2.
92 AEC, p.1, 3; Energy Australia, p.4; CEC, p.2; Momentum Energy, pp.1-2; Tesla, p.3.
93 AER, p.3.
94 Energy Queensland, pp.1-3; AusNet, p.3; TasNetworks, p.2.
95 SA Power Networks, p.3.
96 Joint NSW DNSPs, p.5.
97 Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, p. 31.

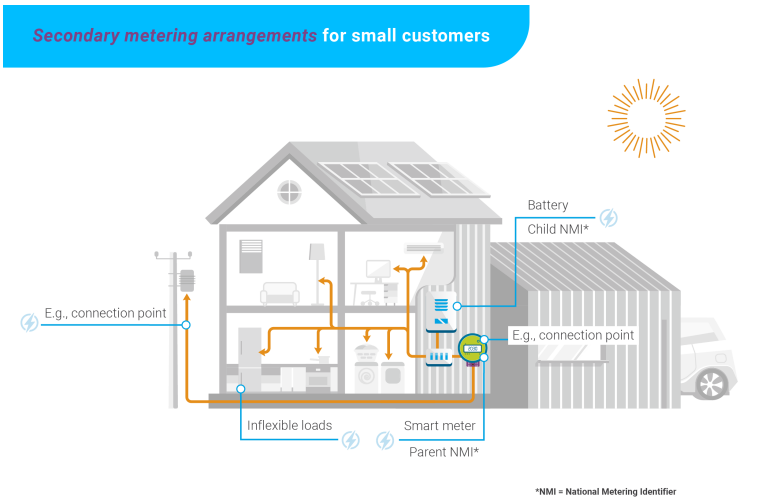
As noted in Chapter two, the Commission considers that the proposed draft rules better advance the NEO and NERO by delivering benefits to consumers through access to different energy products and services for their flexible CER;[98] promoting innovation in the retail energy sector with new energy products and services; and contributing to system reliability and security as they facilitate the integration of flexible CER into the power system, as the market operator AEMO could use these resources at a lower cost. Further details about how these rule changes overall contribute to the NEO and NERO are in Chapter two.

4.2 Proposed supporting arrangements for separating and managing flexible CER at household and small business premises

As noted above, the Commission has developed more preferable draft rules to enable the establishment of secondary settlement points. The key change compared to the existing framework is that flexible CER energy data would be separately metered and provided to market-settlement systems separately from the household's inflexible loads (e.g. lighting).

Figure 4.1 depicts the key elements of the framework for small customers.

Figure 4.1: Secondary metering arrangements for small customers



Source: AEMC

This section outlines the arrangements that will support the draft rules, taking into account stakeholder feedback, Energeia's cost-benefit analysis, and implementation considerations. The supporting arrangements cover:

- market arrangements
- market functionality (roles and responsibilities)
- technical requirements, and
- implementation considerations.[99]

98 As a result of retailers being able to separately meter CER and use it in wholesale markets or for network services.

99 Note that Chapter seven of this paper includes the full spectrum of implementation considerations across all the workstreams of this policy, including for small customers.

4.2.1 Market arrangements

Small customers would continue to only have one FRMP at their premises

As noted in the Directions paper and Section 3.1.1 of this paper, the Commission proposed not to introduce flexible trading with multiple energy service providers for small customers. Therefore, the draft rules provide that a single FRMP per premises is to be responsible for the whole of the customer's supply at their premises, including any secondary settlement points.[100]

That is, the FRMP already financially responsible for the existing connection point at the customer's premises would also be responsible for the energy flows at the secondary settlement point. Amendments to NER Chapter 7 have been drafted to allow a Market Participant to establish one or more secondary settlement points within a premise.

One FRMP at small customer premises is a departure from the AEMO's rule change request, which proposed that all customers would be able to engage multiple FRMPs on their premises. As noted in Chapter three, the majority of stakeholders supported the position presented in the Directions Paper to not progress the proposal for multiple FRMPs at small customer premises.

The Commission notes that a few stakeholders[101] advocated for the multiple FRMPs model to be explored for small customers in the interest of increasing choice for residential consumers. As noted in the Directions Paper, the Commission considers that there may be an opportunity to progress a trial of AEMO's FTM2 model for small consumers via the industry sandboxing arrangements.

Arrangements would be voluntary and aligned with consumer choice

The proposed arrangements would be voluntary and based on consumer preferences and circumstances. This also allows retailers to choose the best option that suits their business model. The voluntary nature of the arrangements is consistent with AEMO's rule change request, is supported by stakeholders, and is consistent with the rule change's aim to increase consumer choice and flexibility.

Subtractive settlement arrangements would apply

As with large customer premises with secondary settlement points (Section 3.3), subtractive settlement arrangements would apply between the primary connection point and secondary settlement point(s) at small customer premises.[102]

The Commission considers that this approach would minimise the need for upgrades to systems currently used by market participants and AEMO. This approach also reflects well-established arrangements used by market participants under the embedded network framework, thereby reducing transaction and system change costs.

These arrangements would be provided for in amendments to AEMO procedures.

Arrangements when the secondary settlement point becomes inactive

The draft rules and AEMO procedures would determine arrangements for when secondary settlement points become inactive. AEMO procedures would provide that where a customer no

100 However, if a customer establishes two separate physical connections to the network, they will still have the ability to appoint different FRMPs for each connection point, as they can today under the current rules. This option is rarely practicable for small customers, because to establish a second connection point they would face a multi-step, lengthy and costly process. Further, DNSPs might be reluctant to allow the establishment of a second connection point for the purpose of sub-loads, as explained in section 3.3.3 of the Directions Paper.

101 Submission to Directions Paper: PIAC, p.7; Master Electricians Australia, p.6.

102 A new paragraph in NER S7.4.3 would clarify that where subtractive metering arrangements are used, the annual energy throughput is the total throughput for the metering installation, not the net throughput after subtraction of the child NMI metering data.

longer wants to use a secondary settlement point, the customer could request the FRMP to declare the NMI for the secondary settlement point to be inactive. In this circumstance, the child NMI at the secondary settlement point becomes inactive and does not trigger subtraction from the parent NMI: this means that energy flows are settled in the market by the FRMP for the connection point (which corresponds to the parent NMI).

As per existing arrangements for inactive NMIs, data would still be collected and all metering roles would stay in place but would not be active. If the customer opts back in, the metering roles become active again. This approach is well understood and used today under the embedded network framework.

Disconnection for non-payment applies at the level of the premises as a whole

The draft rules provide that if the primary retailer seeks to disconnect the premises, existing arrangements for small customers for disconnections would apply.[103] In this scenario, the customer's protections would apply to the premises as a whole (including any secondary settlement points). If the premise is disconnected, the customer would also lose supply at the secondary settlement point (unless it was supplied via the customer's solar PV). Similarly, re-energisation processes and protections would apply to the premises as a whole, meaning that secondary settlement points would automatically be re-energised when the primary connection point is re-energised.

For life support customers, disconnection protection provisions in the NERR would be applied specifically to the secondary settlement point as well as to the premises as a whole.[104]

For the purposes of settlement, AEMO metrology procedures would specify that when MDPs 'flag' to AEMO that there is a disconnection or network outage at the connection point, AEMO can use that flag when processing the metering data for the secondary settlement points (and revert the value to zero).[105] This will then flow through to existing arrangements for settlement under Chapter 3 of the NER.

These arrangements would be provided for through amendments to the NER and NERR aforementioned and amendments to AEMO metrology procedures.

Discovery of existing settlement points

If a customer churns their primary connection point, incoming retailers will be able to know if there exist secondary settlement points (child NMIs) at the customer's premises via the NMI discovery facility. To give effect to this, we have made complementary changes to the NERR, outlined in the draft rule and in Appendix E, Section 4.1.

4.2.2 Market functionality (Roles and responsibilities)

This section sets out roles and responsibilities under the draft electricity rules with respect to establishing secondary settlement points and management of data at these points (NMI standing data).

DNSPs would be responsible for providing secondary NMIs to the consumer's retailer

Under the draft rule, DNSPs would be responsible for establishing and providing the secondary NMIs to the consumer's retailer, for both small and large customers.

103 See the draft retail rule, amending NERR Part 2, Division 9A, and Part 6.

104 Draft retail rule, amendments to NERR rules 59B and 116.

105 New clause 7.16.3(c)(6)(v) of the proposed rule.

As noted in Section 3.3, this is a departure from AEMO's rule change request, but we consider that it is the most efficient option given that DNSPs currently perform this role for primary connection points. Further, it would eliminate the need to create a new market role, and we consider there is value in DNSPs having visibility of secondary settlement points. The Energy Networks Australia (ENA) representatives generally expressed neutral or supportive views of this approach.[106]

These arrangements would be provided for in amendments to Chapters 3 and 7[107] of the NER. AEMO procedures would also describe specific requirements for the process to establish and maintain secondary settlement points.

DNSPs could access data from a secondary NMI if they choose to

As noted in section 4.3, the draft rules provide that DNSPs could access metering data from secondary NMIs if they choose to. The Commission considers that this could deliver benefits including:

- improved network operation and forecasting
- easier procurement of network support services from CER, and
- the development of targeted network tariffs for flexible trading customers.

The Commission considers that the same considerations and benefits apply for small customer premises.

DNSPs generally expressed support for this approach and an interest in having visibility of secondary settlement points to assist with network management and, in some cases, the development of targeted tariffs.

The draft electricity rule amends Chapter 7 of the NER (including clause 7.15.5(c)(7)) to enable DNSPs to access energy flow data from secondary settlement points. These amendments would be supported by changes to AEMO procedures.

Complementary changes to metering roles for type 8 meters

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 FRMP, the existing metering role arrangements should be maintained for secondary settlement points.

As outlined in Chapter five, the Commission has determined that some changes to the roles of metering parties would be required to account for the recognition of in-built measurement technology in devices. Under the draft electricity rule, a Metering Provider would not be required to "install" a meter at a secondary settlement point, but to "commission" it, to account for the metrology being in-built or constructed with the device before being installed on-site.

Some stakeholders have expressed concern during workshops that MCs or retailers are signing customer contracts that may limit access to the customer's real-time meter data (both energy and operational data) and to alternative competitive services. These stakeholders advocated CER interoperability (i.e. devices able to 'work together' irrespective of model and make) and metering interoperability, both supported by open platforms.

While it is not within the scope of this rule to address such issues, the Commission does note its preference for real-time data to be available to consumers and parties who require it, and for

106 These views were expressed in workshops with the project team during consultation between the Directions paper and the Draft determination.
107 NER, New clause 7.2.6 of the proposed rule, in addition to terms that 7.8.2(d)(1) applies.

devices that manage CER to be interoperable. This prevents specific metering kits from locking consumers in and allows customers to benefit from innovative competitive offers in the market. As outlined in Chapter one, these issues are being considered, and we will continue to consider outcomes of progress for this rule change between the draft and the final determination.

Further considerations around the roles and responsibilities of Metering Coordinators and Metering Providers are outlined in Section 5.2.2, in consideration of the new meter types.

4.2.3 Technical arrangements for secondary settlement points - secondary metering arrangements for small customers

New meter type 8 would be able to be used at the secondary settlement point

The draft rules provide that the new meter type (type 8, described in detail in Chapter five) could be used at secondary settlement points at small customer premises. This would enable small customers to use technology with in-built measurement capability at secondary settlement points, such as behind the meter batteries or EV chargers.

As indicated in Section 5.2.3, type 8 meters would need to obtain pattern approval from the National Measurement Institute to give industry and consumers alike confidence in the meter accuracy. However, to introduce flexibility for these metering arrangements and lower metering costs, the draft rules would require AEMO procedures to set out the meter specifications and minimum service specifications for type 8 meters (instead of having the NER define those specifications).

By reducing metering costs associated with the CER device, the Commission considers that this will make it easier for small customers to use their CER flexibly and access new value streams. These benefits are described in more detail at Section 6.2.2.

These arrangements would be provided for in amendments to NER Chapter 7 for the purpose of creating a new meter type and specifying which meter type can be used for second settlement points (see Appendix E - Summary of draft rules, E.3.6).

It would be optional to use the new meter type 8 at a secondary settlement point

Small customers can choose to use a type 4 meter at the secondary settlement point, rather than a type 8. The draft rules provide customers with an option to use a type 8 meter that allows for the use of in-built measurement capability in devices, such as EV chargers, or external meters with lower specifications than type 4 meters (if they are pattern-approved).

Crucially, while this meter type has some lower service specifications, it requires a 2% level of accuracy to retain market confidence in the data being recorded at the secondary settlement point. More details on considerations around accuracy are available in Section 5.2.3.

These arrangements would be provided by amendments to Tables S7.4.3.2 to S7.4.3.6 of the NER (for more details, see Appendix E, 'Table E.1: List of changes to Chapter 7').

In developing metrology procedures for metering services for type 8 meters, AEMO would be guided by the set of principles we listed in Section 5.2.3 in Chapter five (for example, sufficient historical data, compliance with the National Measurement Act[108], and others). This is to ensure that the new meter type meets market expectations for reliability and accuracy, while catering for advancements in CER technology with in-built measurement capability.

108 *National Measurement Act 1960* (Cth)

4.2.4 Implementation considerations

As noted throughout this chapter, a range of changes will be required to implement the arrangements provided for by the draft rules: these include changes to AEMO's system and procedures, AER guidelines, and market participant systems. Under the draft electricity rule, AEMO will be required to make these changes by 2 February 2026, when the rule commences. Chapter seven of this paper further illustrates implementation considerations across all policy workstreams.

4.2.5 The Commission is not making changes for non-market devices and two connection points

In the Directions Paper, we noted that we would consider other options for separately identifying and managing flexible CER. These are:

- Using non-market devices for CER measurement and reward (black boxes), and
- Establishing two connection points to the distribution network at a single premises.

As part of our analysis, we also considered if any changes were needed for multi-element or dual-element smart meters: that is, the settlement point coinciding with an element of the meter.

As part of its analysis against our assessment criteria and in response to stakeholder feedback, the Commission has determined that it will not make rule changes related to these options. Our reasons are outlined below.

Non-market devices for CER measurement and reward (black box)

The Directions Paper noted that some households and businesses are managing CER behind the meter. They use measuring devices that measure the CER but these are not approved under the National Measurement Act (NMA), not permitted by AEMO (i.e. MASS for providing FCAS), or not permitted by the Rules and are therefore not recognised by AEMO market systems.

The Commission is not proposing to make any changes to non-market connected devices because the Rules limiting the measurement of CER for billing purposes sit in the NMA and associated regulations. Given this, changes to the NER/NERR would not be sufficient to allow metering devices that are not approved under the NMA to be used to separately bill CER. Enabling new metering options along with secondary settlement points will provide a better framework for CER network and market integration, but approval by the NMA will be required for these new metering options.

Two physical connection points to the distribution at a single premises

The Commission noted it would consider if there are any changes we could make to the NER and NERR to assist in overcoming the current barriers to establishing a second connection point (e.g. inconsistencies between jurisdictional service installation rules and the requirement to pay two daily fixed network service charges in this scenario).

The Commission proposes not to make any changes to the Rules around daily fixed network charges because we consider that DNSPs should be able to use flexibility in the Rules to offer different charges for CER/EV connections where efficient (i.e. where there is a lower cost of service). Further, and as noted in Chapter one, the AEMC will be undertaking a broader review of the role of network and retail pricing to consider further opportunities to improve consumer incentives for CER flexibility. This review is more appropriate to consider these wider issues and existing arrangements under the NER.

We also note that under the National Electric Vehicle Strategy, officials will work with DNSPs to consider how current jurisdictional service installation rules can be streamlined. We consider that

is a more suitable forum to deal with issues around jurisdictional network connection arrangements.

Dual or multi-element smart meters

The Commission also considered the option of using smart meters to separately identify and measure CER. The Commission notes that these meters can currently be used for network tariffs and retail billing, but not for market settlement purposes. The Commission has determined that this is not a preferred option, based on cost-benefit analysis and implementation considerations. There are challenges associated with enabling the use of multi-element meters registers to be used as NMIs, including limitations in AEMO systems to separate data streams for market settlement. It would likely require significant and costly reconfiguration of AEMO and market participant IT systems in order to achieve separate data streams. The Commission's proposed option is a less costly option that achieves the same outcomes.

5 Measuring energy flows from in-built technology (e.g. street lights, EV chargers, other street furniture)

This chapter outlines the Commission's draft determination and more preferable draft rules to introduce arrangements for two new meter types in the NER that enable technology with in-built measurement capability to be used for settlement and billing. The new meter types are proposed to be meter type 8 and meter type 9 and could be used for technology such as street lights and street furniture, public EV chargers, and electric vehicle supply equipment (ie. EV chargers) used by households and businesses.

The remainder of this chapter sets out:

- An overview of the draft arrangements, including key stakeholder feedback.
- A summary of why we consider these arrangements would benefit customers.
- Detail on the draft arrangements that will support the framework, including:
  - market arrangements
  - market functionality (roles and responsibilities)
  - technical requirements, and
  - implementation considerations.

5.1 Overview of draft new metering arrangements and stakeholder feedback to date

The main features of the draft rule and proposed new type 8 and type 9 meters are:

- Arrangements would be voluntary and cover a range of use cases, including EV chargers and street lights (section 5.2.1).
- The minimum specifications would be set by AEMO in procedures, guided by principles in the NER (section 5.2.3). We expect these specifications to be lower than type 4 meters.
- They would require National Measurement Institute approval (section 5.2.3).
- Street lights and street furniture using a type 9 meter would be able to aggregate multiple loads (ie. multiple street lights) under one NMI (section 5.2.1).
- Metering Providers (MPs) and Metering Data Providers (MDPs) would have new accreditation requirements for each new meter type (section 5.2.2).
- For street lights using a type 9 meter, the Metering Coordinator role would be contestable (section 5.2.2).

5.1.1 AEMO proposed a minor energy flow metering arrangement

AEMO's rule change proposed metering requirements that could accommodate connection arrangements which are currently outside of, or otherwise not considered within, the NEM metering framework. AEMO proposed this for:

- Metering installations connected within a private metering arrangement, not including the primary connection point metering installation which is connected to the network and not within the private metering arrangement.
- Traditionally unmetered 'street furniture' connections (e.g. street lighting, traffic lights, NBN cabinets, publicly provided park hotplates/barbeques, and telecommunications kiosks).

In its rule change request, AEMO used the term 'minor energy flow metering/meters' (MEFM) to identify the proposed metering requirements for these connection types, which are typically associated with flows of energy that are materially lower than those at residential, commercial and industrial metering installations in the NEM. In this paper, the Commission will use the term 'minor energy flow metering' or MEFM when referring to AEMO's proposal or to comments made by stakeholders regarding AEMO's proposal.

5.1.2 Stakeholder views on the minor energy flow metering arrangement

Through submissions and other forms of consultation, stakeholders generally expressed support for AEMO's proposed arrangement[109] including its application to EV chargers.

Stakeholder feedback received in submissions to the directions paper and in subsequent stakeholder workshops as part of the rule change process generally includes:

- The meter types should be voluntary only.[110]
- The minimum service specifications and inspection and testing requirements should be as minimal as possible to ensure a low-cost metering solution. However, accuracy, safety and data quality should not be compromised in the pursuit of a low-cost metering solution. On this, we note feedback that many smart street lights currently on the market in Australia are capable of meeting similar standards to EV chargers in terms of accuracy, remote communications, and data capture.
- The importance of ensuring low costs for the new meter to have any consumer benefits. We note feedback that councils should be well-informed of the costs of taking up an alternative, like AEMO's MEFM proposal, compared to the existing arrangements, given the cost of energy usage in lighting is small.[111]
- A mixed view from stakeholders on whether the MC role for street lights should be contestable or only be available for DNSPs.[112]
- The rules should provide sufficient flexibility to accommodate changes in technology, particularly in international markets. Stakeholders were particularly keen that the Commission consider similar metering arrangements in international contexts.[113]
- Reducing Unaccounted for Energy (UFE) may not be reason enough to change the current arrangements, and trials should be conducted.[114] Consumer advocates noted that there are sufficient overseas examples, that trials would not be needed.[115]

Stakeholders were generally supportive of enabling the use of in-built measurement capability in EV chargers, but noted:

- Concerns about EV charger losses resulting from the conversion from AC to DC at the charger. There was a view that if energy flow was measured after conversion, then losses in the

109 Submissions to Directions Paper: Retailers (Origin, Energy Qld, Momentum), lighting and CER providers (Schreder, Signify, Connected Light Solutions, Master Electricians, OrangeTek), Consumer advocates (IPWEA, Lighting Council Australia, Australian Smart Communities Association, Qld and SA departments of transport).

110 Submissions to Directions Paper: Energy Australia, p. 5-6, Energy Networks Australia, p. 2, Intellihub, p.3, NSW Joint DNSPs, p.7.

111 Institute of Public Works Engineering Australasia (IPWEA), p.12, NSW Joint DNSPs, p.7, Master Electricians, p.10, EnergyAustralia, p.6, Lighting Council of Australia, p.2, several councils and jurisdictions.

112 PIAC, p. 9, Citipower, p.5, and SwitchDin, p.6, considered that only DNSPs should have this role for street lights as they own many of these assets and have the skills to maintain them safely. Queensland Energy Limited, p,11, EnergyAustralia, p.6, Vector Metering, p.9, Master Electricians Australia, p.10, Alinta, p.6, Intellihub, p.2, and others supported a competitive framework for metering services, noting that not all DNSPs wish to do the MC role and other asset owners like transport agencies may want to manage the assets.

113 IPWEA, p.2.

114 Submissions to the directions paper: Origin Energy, p.2, Momentum Energy, p.4.

115 IPWEA, p.6.

conversion process would contribute to unaccounted-for energy (UFE).[116] The Commission considers that this matter could be dealt with by AEMO when it determines meter specifications for type 8 and type 9 meters.

- That accuracy for in-built measurement capability in EV chargers should be tighter where they are the primary meter because EV chargers can use a significant amount of electricity, certainly much more than street lights.[117]

Some stakeholders stated that consideration of the MEFM proposal and alternative arrangements for street lights, in particular, should be done as part of a separate consultation process and rule change.[118]

Some indicated that the proposed meter type may not be appropriate as the primary meter in a small customer or large customer setting but may be suitable behind the meter.[119] This was largely based on concerns around accuracy and minimum standards, all of which have been considered in the development of meter type 9.

5.1.3 These arrangements would benefit consumers and contribute to the NEO and NERO

Energeia's analysis for this element of the draft rule was undertaken separately from the other proposed changes for small and large customers. It focused on the proposals for using in-built measurement capability in the context of kerbside EV chargers and smart street lighting technology. These technologies had the most publicly available data for assessment where these might be used as the meter at the primary connection point (as opposed to the proposed second settlement point at small and large customer premises).

The analysis found that the benefits relate to:

- reduced wholesale costs from dimming street lights - based on average overnight electricity prices for 2022,
- reduced maintenance costs from dimming street lights, and
- avoided metering costs of using in-built metrology for kerbside EV chargers.[120]

Energeia found that the key cost drivers were the additional capital expenditure for smart controls in street lighting and AEMO's implementation costs but estimated relatively small implementation costs associated with this rule change, as it is expected that new streetlight loads would be aggregated similarly to existing practices.[121] Energeia has estimated a small cost per asset for changes to AEMO data flows and procedures.[122] Chapter six and Energeia's report[123] contain more detail on the costs and benefits analysis for this element of the draft rule.

These arrangements will contribute to the NEO and NERO by providing consumers (and their retailers) with lower-cost metering options for their flexible CER and are expected to deliver a range of benefits including:

- supporting the uptake of a lower-cost metering option for street lights, kerbside EV chargers, and other CER devices (i.e. by removing the need to install a separate type 4 meter)

116 This feedback was provided through meetings with stakeholders in industry working groups in November 2023.
117 This was raised as part of an industry working group held by the AEMC in November 2023.
118 Submissions to Directions Paper: AEC, pp. 1-2 and Origin Energy, p. 2.
119 This feedback was provided through meetings with stakeholders in industry working groups in November 2023.
120 Measuring Energy Flows from In-Built Technology (Streetlights, EV Chargers, Other Street Furniture) Analysis- Draft Report, Energeia, 29 Feb 2024,pp. 10-12.
121 Ibid, p. 12.
122 Ibid, pp. 17-18.
123 See: Measuring Energy Flows from In-Built Technology (Streetlights, EV Chargers, Other Street Furniture) Analysis- Draft Report, Energeia, 29 Feb 2024.

- contributing to emissions reductions and lower electricity costs by incentivising the uptake of dimming technology in smart streetlights (as customers would be billed on actual rather than estimated electricity usage thereby making dimming technology more cost-effective)
- promoting innovation in technology with in-built measurement capability, such as batteries.

More information about how these rule changes contribute to the NEO and NERO is provided in Chapter two.

5.2 Draft supporting arrangements for new meter types

This section outlines the arrangements that will support the proposed new meter types, taking into account stakeholder feedback, Energeia's cost-benefit analysis, and implementation considerations. The supporting arrangements cover:

- market arrangements
- market functionality (roles and responsibilities)
- technical requirements, and
- implementation considerations.

5.2.1 Market arrangements

The draft electricity rule differs from AEMO's rule change request because the Commission has determined to introduce two meter types in the NER as shown in Figure 5.1 to accommodate differences in accuracy (as outlined below in Section 5.2.3) and type 8 and type 9 meters can be used in more circumstances than the proposed MEFM.[124] These arrangements would be provided for in amendments to Chapter 7 of the NER.

Figure 5.1 shows that:

- Type 8 meters would have the following characteristics:
  - Permitted for use at second settlement points in small customer premises e.g. EV charger at a second settlement point.
  - In-built measurement devices and external measurement devices would be considered a meter for the purposes of this meter type (if they meet requirements set out in the NER, including pattern approval by the National Measurement Institute).
  - Accuracy limit of plus or minus 2 percent.
  - Volume limit of 750 MWh[125] per annum at the connection point (to use their in-built functions for measuring energy flow, data storage, remote communications, and time as metered data for settlement in MSATS).
- Type 9 meters would have the following characteristics:
  - Permitted for primary connection points other than at small customer premises (e.g. public lighting, street furniture and kerbside charging) and large customer secondary settlement points.[126]
  - In-built measurement devices and external measurement devices would be considered a meter for the purposes of this meter type (if they meet requirements set out in the NER, including pattern approval by the National Measurement Institute).

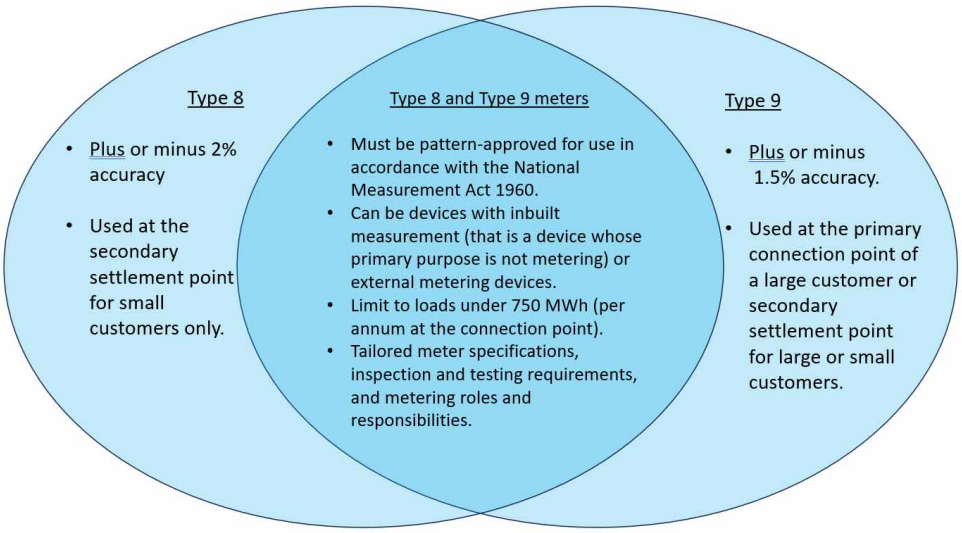
124 For example, meters may be used for flows that are not considered 'minor,' such as NBN cabinets and EV chargers.

125 This is consistent with the annual volume limit for a Type 4 meter.

126 We note that some stakeholders suggested that other small loads such as parking sensors and CCTV cameras could be included in the new metering arrangements. The Commission notes that devices that meet the meter specifications, are pattern approved and function in accordance with Chapter 7 could indeed be considered a type 9 meter for settlement purposes.

- Accuracy limit of plus or minus 1.5 percent.
- Volume limit of 750MWh per annum at the connection point (to use their in-built functions for measuring energy flow, data storage, remote communications, and time as metered data for settlement in MSATS).

Figure 5.1: Type 8 and Type 9 similarities



Source: AEMC

Aggregation of multiple streetlights or street furniture under one NMI

The draft rule would enable multiple street lights and street furniture to be aggregated under one NMI, to reduce NMI establishment fees. This responds to stakeholder feedback about the cost of establishing NMIs, that it is impractical to have a NMI per street light and individual street lights have a small load. Box 1 provides more detail on the aggregation of NMIs.

The definition of a meter installation in Chapter 10 of the NER has been revised to include a central management system (CMS). This will allow street lights to be aggregated through a CMS with a singular NMI and enable the CMS (rather than the individual street lights) to be treated as a metering installation.

If individual measurement components break within lights, they may not need to be replaced immediately if the accuracy of the CMS itself remains within plus or minus 1.5%. This option was determined to be a less complex option than enabling streetlights to revert to a Type 7 metering arrangement (which would require the street lights to be on the NEM load (unmetered loads) table).

Box 1: Aggregation of minor loads under a single national meter identifier (NMI)

Under the NER, meters require a single NMI. However, for type 7 street lights and street furniture where the electricity load is generally minor (e.g. LED street lights for main roads average at 100W), the metrology procedures allow for multiple lights to be aggregated under the one NMI.

DNSPs have advised that this practice is common and that the number of lights aggregated under one NMI can vary significantly between DNSPs and between customers (or, in most cases,

between councils).

The draft rule continues this practice for street lights and street furniture with type 9 meters, which can be aggregated via a central management system included as part of a metering installation. Refer to Appendix D for more details.

Source: AEMC

5.2.2 Market functionality (roles and responsibilities)

The draft rule proposes changes to the accreditation requirements for MPs and MDPs.

In its rule change request, AEMO proposed establishing new accreditation categories for MPs and MDPs for the provision of services within private metering arrangements and minor energy flow metering installations. This included providing a mechanism for the MP to enable the assessment and application of an equivalently accessible display as contemplated by NER clause 7.8.2(a).

AEMO also stated that DNSPs should not be excluded from acting in the role of MC, MDP and MP for street furniture minor energy flow metering installations given these assets are often maintained by DNSPs and housed within DNSP infrastructure.[127]

During consultation, stakeholders noted the following:

- Many MPs sub-contract other parties for the installation of meters.
- Some electric vehicle supply equipment installers have relationships with providers of MP and MDP services, but few of them are accredited to provide this service themselves.
- The MP role is important to ensure that meters are installed correctly and that data is being transmitted to AEMO appropriately.
- The MC has the ultimate responsibility for the metering installation, including inspection and testing. However, the MC may not have the same skills and expertise that an MP has.
- MDPs have their own systems which may not operate with the new in-built measurement technology.
- Requiring an MP to oversee the installation of lights with measurement capability may not be necessary given the measurement technology is in-built and can be monitored remotely through a Central Management System (CMS).
- The cost of metering services, including having an MDP and MP, may be more than initial meter installation costs and could impact the cost benefits of measuring energy flows in street lights.

Minor changes to the MP responsibilities

Based on stakeholder feedback and consideration of existing arrangements, the Commission has determined to make only minor changes to the MP role and responsibilities.

The draft rule includes amendments to NER clauses 7.3.2 and S7.2.2(a) to reflect that customers may provide type 8 metering installations such as EV chargers themselves (including legacy devices), in which case the Metering Provider will be responsible for commissioning and maintaining the installation, but not providing or installing it.

127 Note the IPWEA estimated that approximately 90% of all street lights across Australia are owned by DNSPs.

This change has been proposed to account for the fact that for these new meter types, the metering component may be internal to the CER device and/or already installed and therefore 'installation' of the meter may not be appropriate. Commissioning allows the MP to ensure that the meter has been installed correctly, functions, and transmits data to AEMO appropriately. It is expected that AEMO will make appropriate updates to its accreditation categories and guidelines for accrediting MPs and MDPs.

The MC, MDP, and MP roles are contestable for type 8 and type 9 meters

The draft rule provides for type 8 and type 9 meters to have some different arrangements for metering roles and responsibilities compared to other meter types (notably when compared to Type 4 or Type 7). Under Type 7 or non-contested unmetered loads, DNSPs act as the MC and undertake calculations to determine the electricity usage for settlement purposes.

As noted, a number of submissions supporting the MC role being contestable, noting that many stakeholders agreed it may be most practical for DNSPs to do the role. Energy Queensland Limited noted that it is "important for DNSPs to have the option to perform the MC, MP, MDP functions, but we would not support a mandatory obligation to do so."[128]

Some DNSPs noted that they are trying to move away from providing metering services and as such, allowing other providers to function in the MC role may assist in circumstances where the DNSP does not wish to take on the MC role for Type 9 meters (notably for street lights).[129]

Based on stakeholder feedback and the Commission's assessment criteria, the Commission has determined to make the MP, MC, and MDP roles contestable for type 8 and type 9 metering installations (including smart street lighting). DNSPs could offer this service through their ring-fenced contestable service provider. This approach would enable street lighting customers, namely councils, to benefit from the new meter type without the DNSP needing to provide MC services.

Where DNSPs wish to serve in the role of MC for type 9 metering installation (notably street lights) the Commission is advised that DNSPs can apply to the AER for a ring-fencing exemption.

5.2.3 Technical requirements

Meter requirements and minimum service specifications

AEMO's rule change request proposed that the MEFM should be subject to lower minimum service specifications and be exempt from minimum service specifications under Schedule 7.5 of the NER. Notably, AEMO considered that the display component of the metering installation is one key area where requirements in the NER can be adjusted to accommodate new technologies and metering systems. AEMO suggested that metering systems which allow the end user to access the metering display via an alternative source (e.g. smartphone or in-home display) can provide superior information relative to in-built displays.

AEMO also suggested that concessions provided in clause 7.8.4 should not be extended to minor energy flow metering installations - that is, acceptance of remote communications must be a precursor to private metering arrangement establishment in all cases. AEMO proposes the establishment of a new clause 7.8.4A to accommodate the requirements for minor energy flow metering installations.[130]

128 Energy Queensland Limited, p.11.

129 This feedback was provided through meetings with stakeholders in industry working groups in November 2023.

130 AEMO, Rule change request - Flexible trading arrangements and metering of minor energy flows in the NEM, 6 May 2022, pp. 11-12.

The draft rule proposes that the responsibility for setting metering specifications,[131] inspection and testing requirements (under an asset management plan),[132] and procedures for meter installation and maintenance is placed with AEMO.

The draft rule, however, includes a minimum standard for type 8 and type 9 meters, including for these meters to be pattern-approved. Likewise, requirements for electronic data transfer facilities and facilities for storing interval energy data under clause 7.8.2 of the NER have been extended to type 8 and type 9 meters in the draft rule.

The draft rule would require AEMO to set out the minimum service specifications in their procedures for type 8 and type 9 meters. AEMO must have regard to the principle that a service provided by a type 8 or 9 metering installation must:

- comply with any applicable requirements of the NMA
- provide for the recording of sufficient historical data consistent with current requirements of the NER
- provide for the remote retrieval of metering data
- provide for interval energy data to be prepared and recorded in intervals which correspond to a trading interval.

The Commission expects AEMO will also take into account international standards, consumer and manufacturer cost impacts, and flexibility for the inclusion of new and emerging technologies. We anticipate this approach will make it easier for minimum service specifications to respond to advancements in measurement capability in technology over time. Furthermore, this allows for further consultation with original equipment manufacturers to ensure that minimum service specifications are relevant and achievable for CER devices with in-built measurement capability.

The draft rule allows for alternatives to a physical display

Stakeholders supported removing the requirement for a physical display in submissions, "most lighting control systems have the ability to report on real-time energy consumption... but can't be used in Australia due to current AEMO process and some regulations on meters, most noticeably [the] requirement for a display which is irrelevant when mounted many metres in the air."[133]

As such, the Commission has amended clause 7.8.2 of the NER in the draft rule to allow a meter's display, including that of a type 8 or 9 meter, to be provided by means of a device contained as part of the metering installation or, by some other means, made readily available to the customer with no delay.

We consider this reflects changing consumer preferences towards digitisation, allows for a greater cross section of technologies to be included, and is more practical for devices like street lights.

Meters would need to obtain pattern approval from the National Measurement Institute

Type 8 and 9 meters will need pattern approval from the National Measurement Institute in accordance with the NMA.

The Commission regards pattern approval as a core standard in meter quality assurance and a crucial requirement to give industry and consumers alike confidence in the continued accuracy of their meters.

131 Clause S7.5.2 of the NER.
132 Clause S7.6.1 of the NER.
133 Submission to the Directions Paper: Connected Lights Solutions, p 10.

Pattern approval is discussed further below under implementation considerations.

Alternative inspection and testing requirements

AEMO's rule change request proposed that minor energy flow metering installations be subject to less onerous inspection and testing requirements than other meter types. Specifically, AEMO proposed that Chapter 7 be amended to clarify the ability of MCs to propose bespoke arrangements for the testing and inspection of existing, new, and emerging metering devices, technologies, and systems.

Stakeholders supported tailored inspection and testing requirements citing costs, practicality, and the likely variation between CER devices with in-built measurement capability.[134] For street lights, the IPWEA noted that physical inspection requirements would be particularly impractical and, thus, should be rejected. Rather, 'inspection of performance should more appropriately take place via the central management.'[135]

The draft rule allows the MC for type 8 and type 9 meters to propose alternative testing and inspection arrangements to AEMO for approval through an asset management strategy. If the relevant MC does not have an asset management strategy approved by AEMO, it must comply with the testing and inspection requirements for type 8 and 9 meters outlined in Schedule 7.6 of the NER.

Given the likelihood of a range of CER devices being used under type 8 and type 9, the Commission anticipates that there may be some differentiation of the inspection and testing requirements between the devices. The Commission expects that AEMO will provide guidance in its procedures on preparing asset management strategies for different technologies under type 8 and type 9. The Commission encourages AEMO to consider opportunities to streamline the preparation of asset management strategies, by publishing common strategies used by different devices (i.e. inspection and testing strategies for EV chargers with in-built measurement capability).

The Commission considers the benefits of this approach include:

- Practicality and lower costs for customers - physical inspection and testing can range in cost. However, where measurement capability embedded in the primary device is subject to inspection and testing requirements, the costs can outweigh the benefits. In-built measurement components may be difficult to access because they are internal to the device and not necessarily designed to be accessed after manufacturing. For street lights, in particular, accessing the metering capability to undertake testing may require hiring expensive machinery to access the light suspended many metres above a road. As noted, this cost would likely outweigh the cost savings of measuring energy flow.
- Less complexity - this approach allows for more flexibility for metering coordinators using these meter types. Rather than AEMO or the rules setting a blanket requirement on what is and isn't allowed for inspection and testing requirements, this allows for AEMO's procedures to be responsive to changes in technology.
- Tailored solutions for the technology type which may include sample testing, remote testing or other innovative solutions. This flexibility can accommodate future technologies.

134 Submissions to Directions Paper: Intellihub, p.2, IPWEA, p.9, Master electricians, p.10, NSW Joint DNSPs, p.7, PIAC, p.10

135 IPWEA, p 9. This was echoed by the Australian Smart Communities Association and several councils who made submissions in support of the IPWEA submission.

5.2.4 Implementation considerations

As noted, changes will be required to implement the arrangements provided for by the draft rules. Key changes required to implement the proposed arrangements are likely to include:

- Changes to DNSP, MDP, and retailer IT systems to account for the new meter type arrangements.
- Updates to AEMO procedures, primarily Metrology Procedures, Service Level Procedures, and accreditation requirements for metering providers for the new proposed meter types.

See further information about implementation considerations at Chapter seven.

5.3 Additional considerations

Pattern approval process with the National Measurement Institute

Some stakeholders noted that the success of the meter will depend on whether original equipment manufacturers get pattern approval from the National Measurement Institute (the Institute).[136] Further, that the need for a form of display may be a barrier to achieving pattern approval for type 8 and type 9.

The National Measurement Institute has advised the Commission that:

- Electric vehicle supply equipment (EVSE) (for which the metrological framework and associated requirements are under development), as a whole, are not considered to be electricity meters. This means that in-built or external measurement capability in EVSE would need to follow a separate pattern approval process and meet different requirements. The Institute will work with stakeholders to make pattern approval processes related to EVSE as efficient as possible.
- Achieving pattern approval for an electricity meter which forms part of an EVSE (which may be in-built) under the Institute's M 6-1 pathway is possible and the Institute is open to considering applications.
- Institute document NMI M 6-1 states, in section 1.2 Application: "The National Measurement Institute reserves the right to vary or interpret requirements if it is deemed appropriate to support new or different technologies or applications." This allows the National Measurement Institute to consider alternative or non-physical displays on a case-by-case application for approval.
- There are two other pathways for approval (set out in Institute documents NMI M 13 and NMI R 46), but the same concept applies to all pathways.[137]

The AEMC is also aware of the Institute's ongoing work around pattern approval of EVSE.[138] The Commission encourages industry to work proactively with the National Measurement Institute on pattern approval for type 8 and type 9 meters.

5.4 Questions for stakeholders

The Commission is particularly interested in stakeholder views on the following matters, as these were not covered in the Directions Paper.

136 This feedback was provided through meetings with stakeholders in industry working groups in November 2023.

137 See the National Measurement Institute's website for more information on pattern approval standards here. More information on international standards is also available from the International Organization of Legal Metrology under OIML G 22 Electric Vehicle Supply Equipment (EVSE).

138 See the National Measurement Institute's consultation page on the general certificate of approval for electricity vehicle supply equipment here.

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?

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

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

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?

Question 5: Are there other use cases for type 8 or type 9 meters which stakeholders foresee in future?

Question 6: Are there jurisdictional requirements for DNSPs to serve as MCs for street lights and street furniture which we should be aware of in preparing the final determination?

6 Energeia's cost benefit analysis for the rule change

The Commission considers that there are significant opportunities for consumers individually and collectively from investing in CER. Multiple studies have identified net benefits ranging from $1 billion to $6.30 billion from CER and integration in the power system.[139]

This rule change is critical to realising the broader potential of CER. It will also play a pivotal role in opening up opportunities for innovation, competition and integration of CER that, with other reforms in train, will deliver even greater benefits in the future.

This chapter summarises the draft findings of Energeia's cost-benefit analysis of the draft rule changes. This analysis focuses on the costs and benefits associated specifically with this rule change but also points to additional benefits that could be unlocked through complementary reforms.

It outlines Energeia's modelling approach, limitations, and draft findings for the three core areas presented in the draft determination:

1. Flexible trading with multiple energy service providers at large customer premises
2. Opportunities to optimise CER flexibility for small customers, and
3. Measuring energy flows from in-built technology (e.g., in streetlights, EV chargers, other street furniture).

More detailed information on the analysis is available in Energeia's reports:

- Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024 (Energeia report 1).
- Measuring Energy Flows from In-Built Technology (Streetlights, EV Chargers, Other Street Furniture) Analysis - Draft Report, 29 Feb 2024, published with this determination (Energeia report 2), and
- Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Methodology Report, 3 Aug 2023 (Methodology report).

6.1 Energeia estimated the costs and benefits of the draft rule changes

To conduct its analysis, Energeia modelled the draft rule changes in two streams:

1. The economic costs and benefits associated with the frameworks for:
   - flexible trading with multiple energy service providers at large customer premises, and
   - opportunities to optimise CER flexibility for small customers. Energeia modelled the system costs and benefits, and the uptake required to enable the rule change benefits to balance (or exceed) estimated costs (see section 6.2section 6.2).[140]
2. The economic costs and benefits associated with arrangements for measuring energy flows from in-built technology (streetlights, EV chargers, other street furniture) (see section 6.3).[141]

As noted in the November 2023 methodology report published alongside the Commission's Directions Paper,[142] the AEMC and Energeia are using the first model to provide an estimate of the

139 For example, see CSIRO and Baringa consulting, 2019, and NERA consulting for ARENA, 2022. The ENA Electricity road map estimates around $16 billion in network infrastructure investment could be avoided by orchestration of distributed energy resources.

140 Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024 (Energeia report 1).

141 Measuring Energy Flows from In-Built Technology (Streetlights, EV Chargers, Other Street Furniture) Analysis - Draft Report, 29 Feb 2024 (Energeia report 2).

142 Benefit Analysis of Load-Flexibility from Consumer Energy Resources: Methodology Report, 3 Aug 2023 (Methodology report).

total potential benefits of integrating flexible CER. This analysis is still ongoing and will be published at a later date as a standalone modelling exercise.

As noted in Chapter two, we consider that these rule changes would also deliver benefits associated with:

- Competition, particularly for large customers: supporting competition in the energy retail sector by making it easier for consumers to separate their flexible load from their inflexible load, to have visibility of the value of their CER, and by making it easier for large customers to engage multiple FRMPs at their premises.
- Innovation: a wider range of options for CER device management would become available (i.e. different energy products and service offerings), as well as better opportunities for innovation in technology with in-built metering.

While Energeia did not quantify these benefits, the Commission considers that these reforms could deliver benefits in the form of lower generation and ancillary service costs and greater opportunities for network services agreements offsetting a range of network capital expenditure.

6.1.1 Approach to the modelling for flexible trading at large customer premises and optimising CER flexibility for small customers

This section outlines the process that Energeia undertook to develop its model to analyse the costs and benefits associated with the draft rule changes for small and large customers.

Energeia research informed the technologies considered

Energeia's first step was to conduct desktop research and hold meetings with subject matter experts. Based on this research, the AEMC and Energeia agreed on the technologies to be included in Energeia's analysis:

- water heating for small and large customers
- solar PV for small and large customers
- pools and spas for small customers
- batteries for small and large customers (10 kWh and 150 kWh respectively)
- EV charging (and discharging to grid) for small customers
- ventilation for large customers, and
- refrigeration for large customers.[143]

Energeia identified the potential benefit streams from these technologies

Energeia identified what elements of the electricity market that the technologies could impact. Energeia identified that the relevant benefit streams are:

1. reduced wholesale market/electricity generation costs
2. reduced frequency control ancillary services (FCAS) prices costs
3. distribution network cost savings - both benefits from greater visibility and CER response maximum demand and high voltage events
4. transmission network cost savings, and
5. emissions reduction benefits.[144]

143 Energeia report 1, p. 53; Methodology report, p. 22.
144 Energeia report 1, p. 12.

Energeia also proposed that potential signals to CER devices could come from each of the above.[145]

We agreed on modelling limitations before building the model

Energeia and the AEMC agreed on what trade-offs we would make to balance the model's speed to run, simplicity, and accuracy. Key limitations associated with this model are that it:

- Relies on first order impacts such as the direct impact of CER in offsetting network investments. It does not look at second order impacts such as how increased participation by flexible CER would impact the wholesale price, or how additional benefits to CER owners could increase or speed up CER adoption.
- Applies a 30-minute resolution (i.e. the benefits of wholesale market interactions may be understated by the reduced volatility over the 30-minute resolution).
- Is susceptible to load homogeneity (i.e. the model builds customer impacts based on an existing representative customer which may exaggerate peak and minimum demand).
- Uses network-wide average costs, which is unbiased for overall benefits estimates but on a device-type basis may make it appear as though any adoption would reduce benefits, when it would increase benefits in parts of networks with large potential network cost savings from participation.[146]

These limitations are unlikely to have material impacts on model results and for the most part are conservative in nature, in that they are likely to bias net benefits downward.

Energeia then built a CER flexibility optimisation tool to model how the selected technologies would respond to signals and their impacts on benefit streams.[147] This model, which assumes unrestricted technology use, will inform Energeia's standalone work on total CER benefits that we will publish in the future.

Energeia identified potential scenarios and associated costs

The AEMC worked with Energeia to identify four scenarios each for flexible trading at large customer premises and optimising CER flexibility for small customers.[148] These scenarios are summarised in Table 6.1 for flexible trading and large customer premises and Table 6.2 for optimising CER at residential premises.

Energeia used these scenarios to assess the change in benefits and costs per scenario. Energeia's report focuses on comparing like-for-like scenarios (i.e. comparing scenarios where the VPP has a network services contract with and without the rule change). This drives the net benefit analysis on a per device basis. In addition, Energeia looked at the fixed system upgrade costs of the rule change that are paid for by all customers in the NEM. This drives the benefit threshold analysis.

Table 6.1: Model scenarios for flexible trading at large customer premises

Scenario	Description	Associated marginal costs
Embedded network	The existing set up where large customers form single premises embedded networks	Standalone metering for the child NMI in the embedded

145 Any emissions reduction signals are likely to come through the wholesale market, as wholesale prices tend to be lower when renewables are generating and emissions are low, and accordingly the Energeia modelling does not include separate responses for emissions and wholesale prices.

146 Energeia report 1, pp. 50-51.

147 Energeia report 1, p 14.

148 Energeia report 1, pp 18-19.

Scenario	Description	Associated marginal costs
	to allow two FRMPs to operate, with one controlling the CER device to trade on the wholesale market.	network.
Flexible trading arrangements	The post-rule change set up where large customers are allowed to engage two FRMPs, with one controlling the CER device to trade on the wholesale market.	NMI allocation and connection offer costs.
Embedded network with DNSP services contract	The embedded network scenario where the FRMP controlling the CER device is participating in a DNSP's demand management program.	Standalone metering for the child NMI in the embedded network.
Flexible trading arrangements with DNSP services contract	The embedded network scenario where the FRMP controlling the CER device is participating in a DNSP's demand management program.	NMI allocation and connection offer costs.

Source: Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, p 19.

Table 6.2: Model scenarios for optimising CER for small customers

Scenario	Description	Associated marginal costs
Retailer VPP	A common existing arrangement where small customers enter a VPP arrangement with a retailer who has remote control and access to in-built metering to manage all wholesale costs at the connection point.	No marginal costs.
Rule change VPP	A possible arrangement with the rule change where small customers enter a VPP arrangement with a retailer who has remote control and access to in-built metering to manage all wholesale costs on premises with separate market settlement	NMI allocation and connection offer costs.
Retailer VPP with network services contract	The retailer VPP scenario where the VPP is participating in a DNSP's demand management program.	Standalone metering for the CER device to provide revenue meter quality data to the network.
Rule change VPP with network services contract	The rule change VPP scenario where the VPP is participating in a DNSP's demand management program.	NMI allocation and connection offer costs.

Source: Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, p 18.

6.2 Draft findings for the rule changes for large and small customers

This section sets out the findings of Energeia's cost-benefit analysis associated with the draft rule changes for flexible trading at large customer premises and optimising CER flexibility at small customer premises.

Key findings of Energeia's analysis are:

- The costs of implementing the draft rules are relatively low and are primarily associated with upgrades to AEMO and retailer systems.
- The rule changes would reduce costs and unlock additional benefits. While many of the types of benefits are available today, these rule changes would enable new types of benefits and increase the size of these benefits.
- An achievable proportion of CER devices would need to take up proposed arrangements to cover system costs.
- These rule changes would pave the way for future reforms that would unlock additional benefits from CER devices, including from FCAS.

6.2.1 The costs of implementing the draft rule changes are relatively low

As part of its analysis, Energeia considered costs associated with implementing the draft rule changes for consumers, market participants, and market bodies, including AEMO, retailers, DNSPs, metering parties, and CER device manufacturers.

Energeia has estimated that the key implementation costs would be associated with upgrades to AEMO systems, retailer systems, metering coordinator systems, and NMI allocation costs. Specifically:

- AEMO and retailer systems: Energeia has estimated the costs of updating the costs for AEMO and retailers at $5.2 million per year, each.[149] The amount is based on the annualised costs for AEMO's Distributed Energy Resources Integration Program.[150] We received no submissions from AEMO or retailers on the likely costs of enabling multiple NMIs at sites and multiple FRMPs at large customer sites.
- NMI allocation: Energeia has identified that the participating customer will pay for NMI allocation.[151] The AER regulates NMI allocation charges as alternative control services.
- DNSPs: Enegeia found negligible costs for distribution networks given they already manage multiple data streams for multi-element meters.[152]
- CER device manufacturers: Energeia has identified that CER device manufacturers will have to pay to have their devices certified that they comply with NMI standards and develop the software solutions to allow the metering data to flow into AEMO systems.[153] [154]

For consumers, Energeia has estimated the costs would be:

- $0.98 per customer per year for all customers - those who would and would not be participating with flexible CER (i.e. shared system costs).

149 Energeia report 1, pp 20-21.

150 AEMO, 2022-23 Budget and Fees, p 16.

151 Energeia's estimate of NMI allocation costs includes the site establishment fee and the connection offer service charge. Energeia report 1, p 20.

152 Energeia report 1, p 21.

153 Energeia has assumed the costs of this to market participants (including purchasers of CER devices) are negligible, as scale economies reduce metering costs on a per-device basis and any remaining metering costs would be borne by manufacturers and installers in a competitive market. Many devices today already have in-device metering that is shared with virtual power plant operators outside of market systems.

154 Energeia report 1, p 20.

- A further $8.42 per device per year for customers who participate with NMI-separated, flexible CER (i.e. costs to the customer).[155] [156]

For comparison, the annual electricity cost for households is around $2,700 per year and the cost for small businesses is around $5,100.[157]

The breakdown of estimated costs associated with implementing the proposed arrangements are summarised in Table 6.3More detail on Energeia's estimated costs is available in its Draft Report section 3.1.3.

Table 6.3: Energeia draft findings - costs of implementation - draft rules for flexible trading at large customer premises and optimising CER at residential premises.

Action	Who bears the cost	Annualised cost per device
Updating AEMO systems	All customers	$0.49
Updating retailer/metering coordinator systems	All customers	$0.49
Updating network systems	All customers	Negligible
NMI allocation	Shared by retailer and CER device owner	$8.42
Device certification	CER device owner	Negligible
Device system changes	CER device owner	Negligible

Source: Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, p 20.

Note: We have only included the portion of device certification costs and device system changes incurred by market participants, in this case the purchasers of CER devices. Manufacturers and installers bear any remaining costs. Additionally, Energeia found the costs of system changes to networks are negligible as they can already apply sub-metering arrangements to multi-element meters.

6.2.2 The rule changes would unlock additional benefits

Energeia estimated net benefits associated with the draft rules for flexible trading at large customer premises and optimising CER at residential premises on a per device basis (i.e. CER device).[158]

For each device, Energeia considered five benefit categories, noted in Table 6.4.[159]

Table 6.4: Benefit categories

Benefit type	Allocation of benefits
Network visibility benefits that allow networks to better manage their network: the benefits are accrued by the network by reduced capital expenditure	Shared with the broader consumer base through reduced network charges.
Network peak benefits from the CER devices: the benefit of networks staying within their	Shared by the participating CER consumer, the retailer and network through the terms of

155 Retailers or networks may cover some of this cost in some instances to drive virtual power plant uptake or facilitate network service agreements.

156 Energeia report 1, p 20.

157 Based on the average default market offer in NSW, South Australia and South-East Queensland for 2023-24.

158 It considered a per device basis because the baseline data from AEMO's 2023 Inputs, Assumptions, and Scenarios Report (IASR) assumes that barriers to CER flexibility have disappeared. This approach was considered preferable to estimating specific take-up assumptions, given uncertainty around consumer willingness to participate.

159 The additional benefits for any particular category may be negative.

Benefit type	Allocation of benefits
thermal and voltage limits	network service agreements, with the benefits accrued to the retailer and network shared with all customers through both competition and reductions in network charges.
Wholesale cost benefits: the benefits from purchasing electricity from (or reducing or shifting load from) otherwise passive CER devices instead of building additional generation	Shared by the participating CER consumer, the retailer and eventually through competition to all customers.
Ancillary service benefits: the benefits from purchasing FCAS services from otherwise passive CER devices instead of building additional load and generation	Shared by the participating CER consumer, the retailer, and eventually through competition the broader customer base.
Emissions reduction benefits: the benefits from lower carbon emissions from otherwise passive CER devices instead of large generators, including coal and gas fired power plants.	Shared with society.

Source: Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, p 41.

Findings for core scenarios

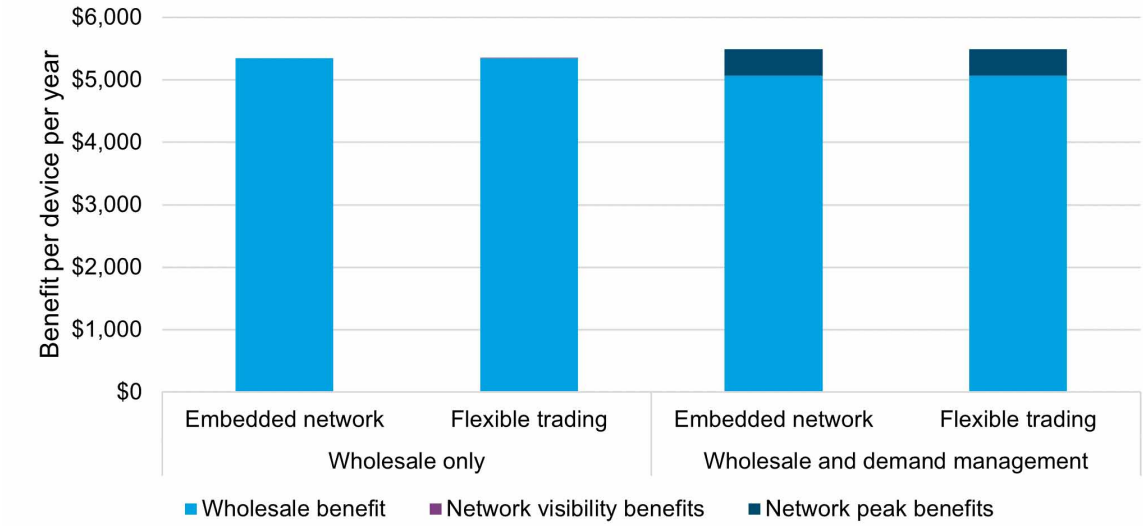
Considering these benefits and the scenarios noted at Table 6.1 and Table 6.2, Energeia made the following observations about benefits that this rule change could deliver:

- Net benefits could be achieved in the following circumstances as a result of savings from using proposed new metering types with a NMI relative to standalone metering costs:
  - Large customers trading flexibly, with and without network services agreements (Figure 6.1shows this relationship for 150 kWh batteries),[160] and
  - Small customers with retailer VPPs with network services agreements[161] (Figure 6.2 shows this relationship for small customer electric vehicle charging where a smart meter is installed at the premises for the first time).
- The rule change could reduce the costs of participating in network services for demand management, because the costs of NMI allocation using an in-built meter are less than installing a separate standalone smart meter to provide reliable data to the distribution network.
- The rule change could deliver wholesale cost benefits, ancillary service benefits and emissions reduction benefits if a NMI leads to the CER device having access to signals not available to it beforehand (e.g. where having a NMI on a CER device means a distribution network offers a network services agreement for demand management).

More details are available in Energeia's draft report, section 3.1.4.[162]

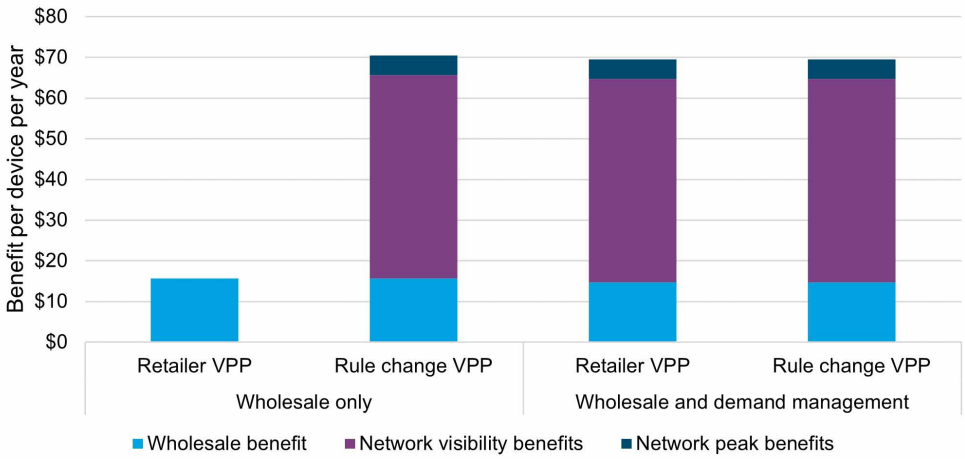
160 Energeia report 1, p 32-33.
161 Energeia report 1, p 31.
162 Energeia report 1.

Figure 6.1: Flexibility benefits of 150 kWh battery under current settings and under optimising CER flexibility for small customers rule change



Source: Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, p 32.

Figure 6.2: Flexibility benefits of small customer electric vehicle charging under current settings and under optimising the value of CER flexibility - small customers rule change



Source: Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, p 31, modified by AEMC for smart metering benefits (as per following section).

Note: We have used 'Rule change VPP' to identify between a retailer VPP operating with multiple NMIs at the premises versus 'Retailer VPP' to identify a retailer VPP operating with a single NMI at the premises.

Findings for alternative scenarios

To supplement its core analysis, Energeia conducted analysis for three additional scenarios:

1. The CER device is only flexible with the rule change - some customers may only be willing to operate their CER device flexibly when its retail billing is separated from the non-flexible load.
2. A new network service agreement - networks may be more willing to provide network service agreements as they are automatically provided revenue-grade device data through standard

market processes rather than having to develop business-to-business data sharing agreements with each virtual power plant.

3. The rule change provides connection point visibility - some customers with flexible CER may not have a pre-existing smart meter and the process of having a NMI allocated to their EV charger or hot water heating might provide network visibility for that connection point.

The net benefits associated with these scenarios are outlined in Table 6.5.

Table 6.5: Net benefits from scenarios not considered in Energeia's draft report ($/year)

Scenario	Net benefits for 10 kWh batteries	Net benefits for EV charging	Net benefits for150 kWh batteries	Net benefits for large customer ventilation	Benefit sources
The CER device is only flexible with the rule change	$345	$7	$5,335	**$1,123**	Wholesale costs/avoided generation expenditure and lower emissions.
A new network services agreement	$8	**n/a**	**$137**	$107	Network costs through delayed network augmentation partially offset by marginally higher wholesale costs and emissions.
The rule change provides connection point visibility	$50	$50	$50	$50	Network costs through improved visibility.

Source: AEMC analysis and ENA, Review of Smart Metering, 2014.

Note: When a VPP gains a network service agreement it will not use all of its access to the CER device to manage wholesale costs, at times it will decide to focus on network demand management. As a result, it will be slightly less active on the wholesale market, which leads to a marginal increase in wholesale costs and emissions.

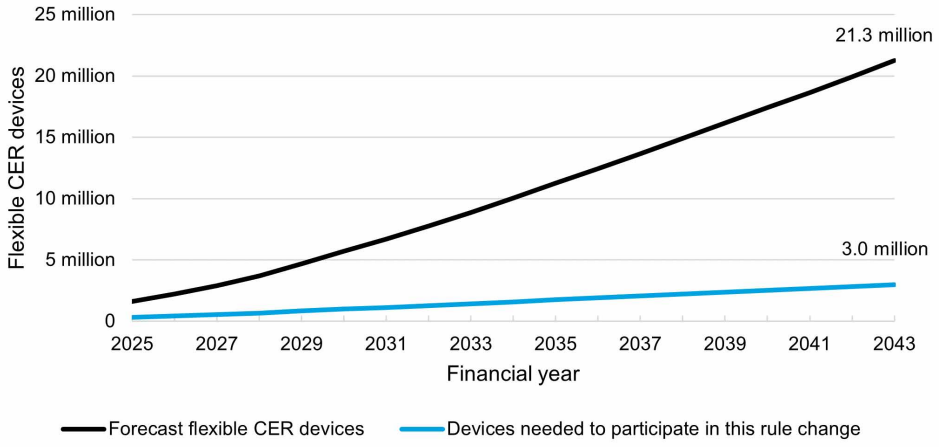
6.2.3 An achievable proportion of CER devices would need to take up proposed arrangements to cover system costs

To test whether the benefits of the draft rule change would exceed associated costs, Energeia and the AEMC have conducted break even analysis to identify how many devices would need to participate for benefits to exceed fixed costs and per device costs.

Breakeven analysis for consumers participating

Figure 6.3 shows the estimated take up needed for market benefits to exceed market costs compared to the device uptake forecast in the Draft 2024 ISP to 2043. The Commission considers that the estimated uptake is plausible and supports the pursuit of the draft rules.

Figure 6.3: Break even estimates for flexible CER devices needed to participate in the rule changes



Source: Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, p 39.

Breakeven analysis for consumers who are not participating

Energeia also conducted break even analysis in relation to consumers who would not be participating in the proposed arrangements. It found that if participation (comparing scenarios with and without multiple NMIs but with the same incentives available) exceeded the economic break even point, consumers without separately metered CER devices would see lower electricity costs.[163]

Benefits not taken into account

We note that Energeia's analysis does not take into account a number of additional benefits that we anticipate will be unlocked by these rule changes, including:

- locational variation driving opportunities for network demand management,[164]
- lower barriers to entry and associated costs, competition benefits of increased retail offers both for large and small customers,[165] and
- further reforms that could unlock more value from CER devices that may be more likely with this rule change.[166]

These could increase the market benefits and the benefits for non-participating customers.

6.2.4 These rule changes would pave the way for future reforms that would unlock additional benefits from CER devices

As part of its analysis, Energeia also identified future reforms that would unlock additional benefits and build on the benefits unlocked by the draft rule changes:

1. Allowing FCAS participation from in-device metering (with the necessary accuracy and other standards) through changes to the MASS.
2. Network businesses could offer cost reflective tariffs to CER devices using the metering data that these rule changes enable.

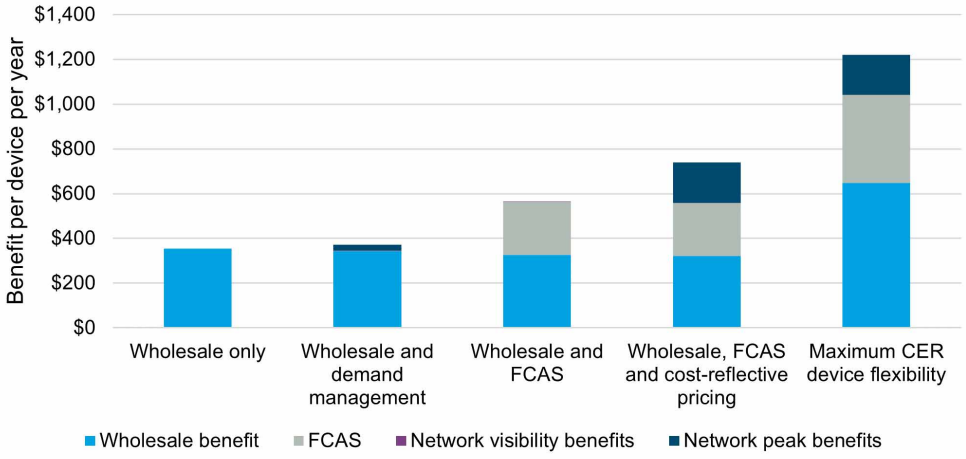
163 Energeia report 1, p 41.
164 Energeia report 1, p 32.
165 Energeia report 1, p 6.
166 Energeia report 1, pp 41-49

3. Customers agreeing to allow virtual power plant operators greater access to the CER device (currently most retailer-led virtual power plants are limited to around 50 days of operation per year).[167]

Figure 6.4 shows the potential additional value for a 10kWh battery[168] from unlocking additional CER benefits and Figure 6.5 does the same for large customer ventilation systems.

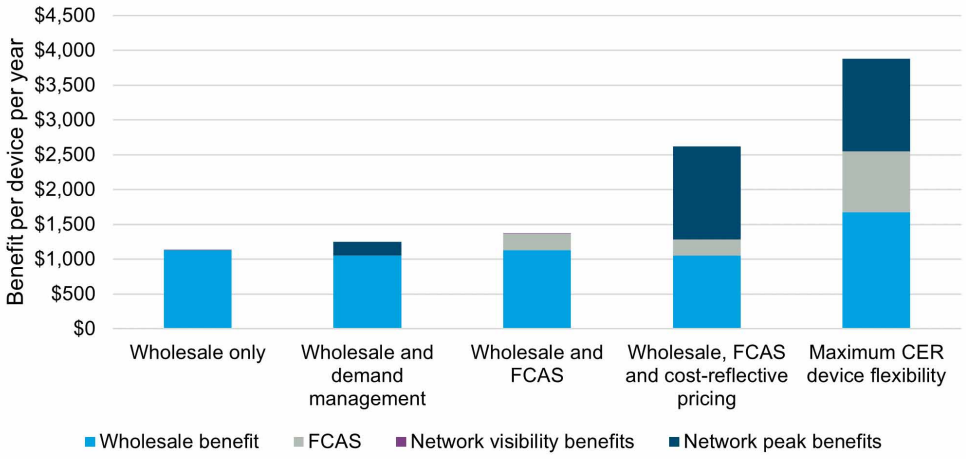
As noted in the executive summary, there is a range of work being done to integrate CER into the NEM, including the development of the Commonwealth's CER implementation plan and work such as the AEMC's forthcoming review of network and retail pricing.

Figure 6.4: Additional CER benefits unlocked from FCAS, cost-reflective network pricing, and greater virtual power plant access to 10kWh batteries



Source: Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, p 46.

Figure 6.5: Additional CER benefits unlocked from FCAS, cost-reflective network pricing, and greater virtual power plant access to large customer ventilation systems



Source: Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024, p 48.

167 Energeia report 1, pp 42-44.

168 Which is representative of household batteries.

6.3 Draft findings for the rule change for measuring energy flows from in-built technology

6.3.1 Approach to the model

For this aspect of the rule change, Energeia's cost-benefit analysis focused on two technologies:

1. Smart street lighting with in-built metering.
2. Kerbside electric vehicle chargers with in-built metering.[169]

Energeia focused on these technologies due to the estimated benefit associated with the uptake of these technologies and the availability of data to undertake the modelling.

To conduct its analysis, Energeia considered two scenarios:

1. The base case - All new and replacement street lights would use LEDs without smart controls and kerbside EV chargers would need separate metering that aligns with current NER requirements.
2. The rule change - All new and replacement streetlights would use LEDs with smart controls and kerbside EV chargers would use internal metrology that aligns with the draft determination.[170]

Energeia estimated that key benefits that this rule change could deliver are:

- reduced wholesale costs from the use of dimming technology in street lights (the ability to dim street lighting during low traffic hours) and being able to directly measure energy flows from the technology (instead of using an algorithm),
- reduced maintenance costs from the use of dimming technology in streetlights,
- reduced CO_2e emissions from the use of dimming technology in streetlights, and
- avoided metering and metering installation costs (as a result of being able to use technology with in-built metrology).[171]

Energeia estimated that the key cost drivers associated with this rule change are:

- additional capital expenditure for investment in smart streetlights, and
- AEMO implementation costs associated with updating procedures and managing data flows from technology with in-built metering.[172]

6.3.2 The rule change could deliver $106m in net benefits from measuring energy flows from in-built technology

Energeia's cost-benefit analysis has estimated that the draft rule could deliver a net benefit of $84 million in net present value over 20 years (excluding emissions benefits). It could also deliver over 262,000 tonnes of CO2 emissions reductions (over 20 years), valued at $22 million[173] applying the NSW Treasury carbon value.[174]

By technology type, Energeia has estimated the following benefits:

- $84 million from smart street lighting with in-built metering, and

169 Energeia report 2, p 7.
170 Energeia report 2, p 10.
171 Energeia report 2, pp 10-12.
172 Energeia report 2, p 12.
173 Energeia report 2, pp 19-20.
174 Technical note to NSW Government Guide to Cost-Benefit Analysis TPG23-08, Carbon value in cost-benefit analysis, NSW Treasury, 2023, available here.

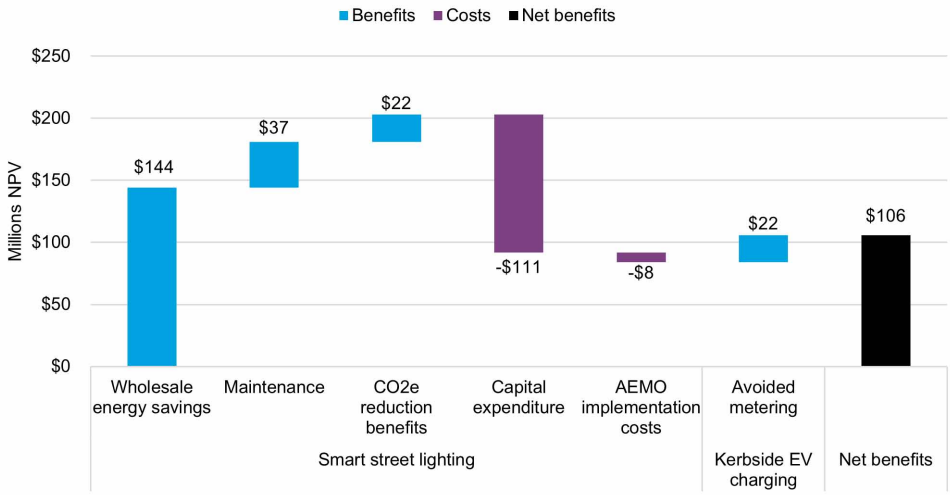
- $22 million from kerbside electric vehicle chargers with in-built metering.[175]

These findings are summarised at Figure 6.6

Over 20 years, these benefits exceed the initial capital expenditure costs of installing higher cost smart street lights and AEMO's implementation costs. These findings indicate that the rule change has the potential to deliver significant benefit to consumers (noting that benefits to local councils for streetlights will flow through to residents) and will contribute to the NEO and NERO.

More detail on Energeia's findings is available in Energeia's accompanying report.[176]

Figure 6.6: Costs and benefits for improving metering options for smart street lighting and kerbside EV charging



Source: Measuring Energy Flows from In-Built Technology (Streetlights, EV Chargers, Other Street Furniture) Analysis - Draft Report, 29 Feb 2024, p 3.

175 Energeia report 2, p 20.
176 Energeia report 2.

7 Implementation considerations

The Commission has engaged closely with stakeholders through a variety of forums to identify the nature and expected scale of costs that would be required to give effect to the proposed arrangements. The draft rules have been developed with the aim of minimising costs for market participants and consumers, while creating new opportunities for consumers to separate and use CER in different ways and utilise in-built measurement capability in technology - including CER devices.

Based on stakeholder feedback and Energeia's cost-benefit analysis, the Commission has identified that the following changes will be required to implement the arrangements provided for by the draft rules:

- Updates to AEMO's MSATS system, primarily related to the management of secondary NMIs.
- Updates to AEMO procedures, primarily MSATS Procedures, Metrology Procedures, and Service Level Procedures.
- Updates to AER guidelines related to embedded network arrangements, particularly Network Exemption Guidelines and Retail Exemption Guidelines
- Changes to retailer billing systems to account for the existence of secondary settlement points, and
- Updates to DNSP systems to enable the establishment and maintenance of secondary NMIs.

In its cost-benefit analysis, Energeia has costed the key changes associated with these rule changes. For rule changes related to small and large customers, Energeia estimates that key costs would arise from:

- AEMO system changes/updates
- retailer and DNSP system changes, and
- metering and NMI allocation costs.

For the rule change to enable measurement of energy flows in technology such as smart streetlights and kerbside EV chargers, Energeia estimates that key costs would arise from:

- cost of purchasing smart light controls
- DNSPs establishing NMIs and maintaining NMI data, and
- AEMO upgrading procedures to cater for the proposed new meter types.

The costs associated with these changes are described in more detail in Chapter six and Energeia's draft reports.[177]

The timeline for implementing the rule change is estimated to be approximately 18 months. We are consulting with AEMO, the AEMO reform delivery committee, and the National Measurement Institute between the draft and final determination on implementation considerations. As outlined, a commencement date has been proposed for 2 February 2026.

177 Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024; Measuring Energy Flows from In-Built Technology (Streetlights, EV Chargers, Other Street Furniture) Analysis - Draft Report, 29 Feb 2024.

A Rule making process

A standard rule change request includes the following stages:

- a proponent submits a rule change request
- the Commission initiates the rule change process by publishing a consultation paper and seeking stakeholder feedback
- stakeholders lodge submissions on the consultation paper and engage through other channels to make their views known to the AEMC project team
- the Commission publishes a draft determination and draft rule (if relevant)
- stakeholders lodge submissions on the draft determination and engage through other channels to make their views known to the AEMC project team, and
- the Commission publishes a final determination and final rule (if relevant).

For this project, due to the complex issues raised in the rule change request and in submissions, we included an additional stage in the process and published a directions paper in August 2023. We plan to extend the time to publish the final determination and final rules to mid-2024. You can find more information on the rule change process on our website.[178]

A.1 AEMO proposed a rule to introduce flexible trading and a minor energy flow meter

AEMO proposed to introduce flexible trading by enabling consumers to have their CER separately identified, and therefore treated independently in market settlements - allowing consumers to engage with multiple energy service providers if they choose to.

AEMO proposed a model and arrangements to enable more flexible trading. AEMO's proposed model would create new secondary settlement points for CER behind consumers' current meters. AEMO proposed that a consumer could choose to have one secondary settlement point for all of their controllable or flexible resources, while keeping all of their other electrical load measured by their primary settlement point and on a separate contract. Alternatively, a consumer could choose to have individual secondary settlement points for individual devices. In both cases, the proposal was for the arrangements to be made for and by one customer. Under AEMO's proposal, the consumer could contract with more than one financially responsible market participant (FRMP) for individual devices or one for less flexible load and another for their flexible load - or all of their resources could be managed by one FRMP, but with different types of pricing.

AEMO also put forward that current metering requirements would create barriers to the establishment of secondary settlement points. To address this, AEMO proposed establishing a new category of minor energy flow meter in the rules. This metering installation could then be used at secondary settlement points. AEMO also proposed that this new type of meter should also be able to be used for currently un-metered loads, such as streetlights and street furniture.

A.2 The proposal addressed barriers to consumers separating their CER and engaging multiple energy service providers at their premises

AEMO's proposal sought to address barriers to consumers being able to have their CER separately identified and therefore treated independently in market settlements and to consumers to engage with multiple energy service providers if they choose to. In its rule change proposal, AEMO noted

178 See our website for more information on the rule change process here

barriers that prevent or disincentivise consumers from separating their CER and engaging multiple energy service providers, including:

- existing network policies
- the time it takes to obtain a second connection, costs to consumers, including potential for additional distribution network access chargers
- the practicality of adding the connection (e.g. requirements on size and location of fusing, metering, and other equipment)
- current metering requirements, which create barriers (namely complexity and costs) to the establishment of secondary settlement points, such as the necessary size of meters in the current rules.

A.3 It proposed to do so by making it easier for consumers to separate their CER and engage multiple energy service providers, and reducing barriers related to metering

AEMO recommended a new flexible trading model with secondary settlement points and a new meter type that could be used at secondary settlement points and to measure energy at currently unmetered loads. The proposal addresses the issues above in the following ways:

- Consumers with CER devices would be able to separate their flexible devices (e.g. pool pump, battery, hot water heater) from their passive load (e.g. lighting, household appliances).
- Consumers with their separately metered CER would have access to different products and services and ways to participate in the market (e.g. wholesale market and network services).
- Would make it easier for large customers to establish secondary settlement points and choose to engage different energy service providers to manage their flexible CER at these points.
- Retailers would have better visibility of the value of flexible CER and can use this to participate in the wholesale market, provide network services, and offer different products to consumers.
- Assets with in-built measurement capability could be used for settlement and billing purposes (subject to National Measurement Institute approval). For example, using equipment inside an EV charger to measure energy would remove the need for a separate meter. Or, measuring energy flows from currently unmetered streetlights would unlock benefits such as reduced metering costs, reduced wholesale costs, and emissions reductions.

A.4 The process to date

On 8 December 2022, the Commission published a notice advising of the initiation of the rule making process and consultation in respect of the rule change request.[179]

A consultation paper identifying specific issues for consultation was also published. The Commission considered all issues raised by stakeholders in submissions, and responded to them in the directions paper, published on 3 August 2023. We received 53 submissions on the directions paper. Issues raised in submissions on the directions paper are discussed and responded to throughout this draft rule determination.

A summary of other issues raised in those submissions and the Commission's response to each issue is contained in Appendix F.

179 This notice was published under section 95 of the NEL and section 251 of the NERL.

B Regulatory impact analysis

The Commission has undertaken regulatory impact analysis for this draft determination and more preferable draft rules.

B.1 Our regulatory impact analysis methodology

We considered a range of policy options

The Commission compared a range of viable policy options within our statutory powers. The Commission analysed these options: the rule proposed in the rule change request; a business-as-usual scenario where we do not make a rule; and a more preferable rule allowing consumers to more easily separate and manage flexible loads, use flexible CER in different ways, and make use of in-built measurement capabilities of CER devices. These options are described in Chapter three of the draft determination.

We identified who would be affected and assessed the benefits and costs of each policy option

The Commission's regulatory impact analysis for this rule change used qualitative and quantitative methodologies. It involved identifying the stakeholders impacted and assessing the benefits and costs of policy options. The depth of analysis was commensurate with the potential impacts. Where commensurate and feasible, the Commission has quantified the impacts. The Commission focused on the types of impacts within the scope of the NEO and NERO.

Table B.1 summarises the regulatory impact analysis the Commission undertook for this rule change. Based on this regulatory impact analysis, the Commission evaluated the primary potential costs and benefits of policy options against the assessment criteria. The Commission's determination considered the benefits of the options minus the costs.

Table B.1: Regulatory impact analysis methodology

Assessment criteria	Primary costs	Primary benefits	Stakeholders affected	Methodology
Outcomes for consumers	No economic costs	Greater choice for customers on how they use their CER devices (making it easier to access network and retail pricing offers for CER assets) Access to lower-cost metering options by allowing consumers to use in-built measurement capability in technology Potential to reduce electricity costs for all consumers	• CER device owners • All electricity customers.	Energeia's quantitative analysis estimates the benefits of the rule changes for the customers participating, and what costs and benefits are shared with the broader customer base We considered stakeholder feedback on how customers could incur costs and benefits from the proposed rule changes
Innovation and flexibility	No economic costs	A wider range of options for CER device management (i.e. different energy products and service offerings) Opportunities for innovation in technology with in-built metering	• CER device manufacturers • Retailers • Third-party aggregators • CER device owners.	We engaged with stakeholders, including third-party aggregators, metering providers, retailers, and DNSPs on the opportunities for innovation that this rule change would create
Principles of market efficiency, particularly competition	No economic costs	Gains in allocative efficiency from exposing CER devices to better cost signals will drive dynamic efficiency gains over time Competition in the energy retail sector	All	Energeia's quantitative analysis estimates the long-run savings from greater CER device participation, in-built metering and smart street lighting to the energy system We considered stakeholder feedback on the

Assessment criteria	Primary costs	Primary benefits	Stakeholders affected	Methodology
		by making it easier for consumers to separate their flexible load from their inflexible load Networks could procure demand and export management services more efficiently from CER resources, helping to reduce the need for network augmentation		opportunities for increased retail competition through disaggregating existing energy services and encouraging new energy services
Safety, security and reliability	No economic costs	Networks would have better visibility of subloads (i.e. flexible CER), to plan for future infrastructure upgrades more accurately, such as network augmentation and the timing of replacement expenditure, which may help maintain reliability. Networks may also have a greater ability to enter into network services agreements with aggregated CER traders	All electricity consumers	We considered stakeholder feedback on whether the proposed rule changes would enable increased opportunities for CER to participate in network services and ancillary service markets
Implementation considerations	Costs for system changes for AEMO, retailers and DNSPs; Metering and NMI allocation costs; Capital costs for upgrading street lights	No economic benefits	• AEMO • Retailers • Owners and operators of CER devices • All customers	Energeia's quantitative analysis investigated the implementation costs of system changes incurred by AEMO, DNSPs, and retailers; individual costs for CER device owners; costs for councils upgrading street lighting and parties installing kerbside EV chargers
Emissions	No economic costs	Estimated reduction of 267,000 tonnes	All	Energeia's quantitative analysis estimated the

Assessment criteria	Primary costs	Primary benefits	Stakeholders affected	Methodology
reductions		of CO_2e from smart street lighting		emissions changes emanating from the rule change by considering reduced overnight use by streetlights. Changes in emissions reductions from wholesale market activity from introducing flexible metering arrangements to small and large customers are likely to be marginal

B.2 Cost-benefit analysis

Energeia has conducted a comprehensive cost-benefit analysis of the draft rule changes. The methodology in Table B.1 reflects the methodology utilised by Energeia to conduct its analysis. The findings of this cost-benefit analysis are summarised in Chapter Six and detailed in full in Energeia's draft reports published with this draft determination.[180]

180 Benefit Analysis of Load-Flexibility from Consumer Energy Resources - Draft Report, 29 Feb 2024; Measuring Energy Flows from In-Built Technology (Streetlights, EV Chargers, Other Street Furniture) Analysis - Draft Report, 29 Feb 2024.

C Legal requirements to make the draft rules

This appendix sets out the relevant legal requirements under the NEL and NERL for the Commission to make a draft rule determination.

C.1 Draft rule determination and draft rules

In accordance with sections 99 of the NEL and 256 of the NERL, the Commission has made this draft rule determination for more preferable draft electricity and retail rules in relation to the rule change proposed by AEMO.

The Commission's reasons for making this draft rule determination are set out in chapter 2.

The more preferable draft rules are attached to and published with this draft determination. Their key features are described in Appendix E.

C.2 Power to make the draft rules

The Commission is satisfied that the more preferable draft rules fall within the subject matter about which the Commission may make rules.

The more preferable draft electricity rule falls within section 34 and schedule 1 of the NEL as it relates to:

- section 34(1)(a)(iii) - the activities of persons (including Registered participants) participating in the national electricity market or involved in the operation of the national electricity system
- section 34(1)(aa) - facilitating and supporting the provision of services to retail customers
- section 27 of schedule 1 - the metering of electricity to record the production or consumption of electricity
- section 28 of schedule 1 - the registration of metering installations used to meter electricity.

The more preferable draft retail rule falls within section 237(1)(a)(ii) of the NERL as it relates to the activities of persons involved in the sale and supply of energy to customers.

C.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL and NERL to make the more preferable draft rules
- the rule change request
- submissions received during consultation on the consultation paper and the directions paper
- the ways in which the draft rules would or are likely to contribute to the achievement of the NEO and NERO, including considering the targets in the emissions target statement[181]
- the application of the more preferable draft electricity rule to the Northern Territory
- the extent to which the more preferable draft retail rule is compatible with the development and application of consumer protections for small customers.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[182]

181 In accordance with NEL s. 32A(5) and NERL s. 224A(5).

182 Under s. 33 of the NEL, the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for energy.

The Commission may only make an electricity rule that has effect with respect to an adoptive jurisdiction if satisfied that the proposed rule is compatible with the proper performance of AEMO's declared network functions.[183] The more preferable draft electricity rule is compatible with AEMO's declared network functions because the rule would not affect those functions.

C.4 Making electricity rules in the Northern Territory

The NER, as amended from time to time, apply in the Northern Territory, subject to modifications set out in regulations made under the Northern Territory legislation adopting the NEL.[184]Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.

As the more preferable draft electricity rule relates to parts of the NER that apply in the Northern Territory, the Commission is required to assess Northern Territory application issues, described below.

Test for scope of "national electricity system" in the NEO

Under the NT Act, the Commission must regard the reference in the NEO to the "national electricity system" as a reference to whichever of the following the Commission considers appropriate in the circumstances having regard to the nature, scope or operation of the proposed rule:[185]

1. the national electricity system
2. one or more, or all, of the local electricity systems[186]
3. all of the electricity systems referred to above.

Test for differential rule

Under the NT Act, the Commission may make a differential rule if it is satisfied that, having regard to any relevant MCE statement of policy principles, a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.[187] A differential rule is a rule that:

- varies in its term as between:
  - the national electricity systems, and
  - one or more, or all, of the local electricity systems, or
- does not have effect with respect to one or more of those systems

but is not a jurisdictional derogation, participant derogation or rule that has effect with respect to an adoptive jurisdiction for the purpose of s. 91(8) of the NEL.

A uniform rule is a rule that does not vary in its terms between the national electricity system and one or more, or all, of the local electricity systems, and has effect with respect to all of those systems.[188]

In developing the more preferable draft rule, the Commission has considered the application to the Northern Territory according to the following questions:

183 Section 91(8) of the NEL.

184 These regulations under the NT Act are the National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations 2016

185 Clause 14A of Schedule 1 to the NT Act, inserting section 88(2a) into the NEL as it applies in the Northern Territory.

186 These are specified Northern Territory systems, listed in schedule 2 of the NT Act.

187 Clause 14B of Schedule 1 to the NT Act, inserting section 88AA into the NEL as it applies in the Northern Territory.

188 Clause 14 of Schedule 1 to the NT Act, inserting the definitions of "differential Rule" and "uniform Rule" into section 87 of the NEL as it applies in the Northern Territory.

- Should the NEO test include the Northern Territory electricity systems? Yes. The Commission considers that the NEO test should include the Northern Territory electricity systems given that this rule will apply in the Northern Territory.
- Should the rule be different in the Northern Territory? No. The Commission's draft rule is a uniform rule because the Commission does not consider it appropriate for the draft rule to be different in the Northern Territory.

C.5 Civil penalty provisions and conduct provisions

The Commission cannot create new civil penalty provisions or conduct provisions. However, it may recommend to energy ministers that new or existing provisions of the NER or NERR be classified as civil penalty provisions or conduct provisions.

The NEL and NERL set out a three-tier penalty structure for civil penalty provisions in the NEL and NERL and the NER and NERR.[189] A Decision Matrix and Concepts Table,[190] approved by Energy Ministers, provide a decision-making framework that the Commission applies, in consultation with the AER, when assessing whether to recommend that provisions of the NER and NERR should be classified as civil penalty provisions, and if so, under which tier.

The Commission does not propose to recommend that any new provisions in the NER or NERR, introduced by the draft rules, be classified as civil penalty provisions or conduct provisions.

Where the draft rules amend provisions that are currently classified as civil penalty provisions, the Commission does not propose to recommend to energy ministers any changes to the classification of those provisions.

The more preferable draft rules do not amend any provisions that are currently classified as conduct provisions under the National Electricity (South Australia) Regulations or the National Energy Retail Regulations.

189 Further information about civil penalties is available here

190 The Decision Matrix and Concepts Table is available here

D Summary of draft rules

D.1 Overview

This Appendix outlines the amendments to the NER and the NERR that would be made by the draft rules.

If made, the amendments would commence on 2 February 2026. The draft amendments described in this Appendix relate to the NER and NERR as they will be in effect on the commencement date. This includes changes made by rules already made but not yet in force as at the date of this draft determination. This includes the 'Integrating Energy Storage into the NEM' changes that will commence on 3 June 2024 and introduces new terminology throughout the NER including 'Integrated Resource Provider' and 'Small Resource Aggregator'.

D.2 NER key concepts

Under the draft rule amending the NER, secondary settlement arrangements would be introduced by allowing a Market Participant to establish a metering installation within the premises of an end user as a 'secondary settlement point'. There would be some restrictions; for example, a secondary settlement point could not be established at premises that are the location of scheduled plant, or within a regulated SAPS, or in place of a child connection point in an embedded network. More than one secondary settlement point could be established at the same premises.

A subset of secondary settlement points would be 'small resource secondary settlement points'. This would be the equivalent of small resource connection points, but used for small resources (e.g. for small batteries or small generating units) at secondary settlement points.

Amendments to Chapter 2 would allow a secondary settlement point (including a small resource secondary settlement point) to be classified as a 'market connection point'. The term 'market connection point' currently refers only to connection points for which a Market Participant is financially responsible. The draft rule uses the same term for secondary settlement points that have been classified, but secondary settlement points are not intended to be a type of 'connection point' as that term is defined in NER chapter 10.

Classification of a market connection point results in the classifying Market Participant becoming the financially responsible Market Participant or FRMP for the point. Chapter 2 would require that for small customers, the same Market Participant must be the FRMP for the connection point and any secondary settlement points within the customer's premises.

Amendments to chapters 3 and 4A would give effect to the secondary settlement arrangements in settlement and under the retailer reliability obligation. Amendments to chapters 6 and 6B would provide for network charges to be billed to the retailer for the connection point and not the FRMP for the secondary settlement point. This will impact only large customers with secondary settlement points since. For small customers, the retailer will be the FRMP for both.

The draft rule would also provide for the two new metering installation types. The changes are primarily in chapter 7, with a consequential change in chapter 6.

D.3 Draft NER amendments by chapter

D.3.1 Chapter 2 - Registered participants and registration

Chapter 2 specifies the obligation to register to buy and sell electricity through the NEM and the criteria for eligibility to register as an Integrated Resource Provider, including where participating

as a Small Resource Aggregator, or Customer or to become a Metering Coordinator. Consequential changes to clauses 2.1A.3, 2.1B.2 and 2.1B.4 and rule 2.4A would extend these provisions to accommodate secondary settlement points.

Several provisions in chapter 2 specify that the Market Participant must, in relation to a market connection point for which it is the FRMP, purchase all electricity supplied through the national grid to the market connection point from the spot market. These provisions (clauses 2.2.4(d), 2.2.5A(c), 2.2.8(e) and 2.3.4(g)) would be amended to clarify that where the market connection point is a connection point with a related secondary settlement point, this obligation applies only to the net flow at the connection point. This deals with the possibility that, at a large customer site, there may be a different FRMP for the connection point and secondary settlement point.

The provision under which an Integrated Resource Provider may classify a small resource connection point as one of its market connection points (as a Small Resource Aggregator) would be extended to allow for the classification of small resource secondary settlement points within the premises of a large customer (clause 2.8.8, with a consequential change at draft new clause 2.3.4(a1)). This would not be extended to the premises of a small customer because a small customer would have the same FRMP for both the connection point and small resource secondary settlement point, in which case the Integrated Resource Provider would need to be a retailer and not a Small Resource Aggregator.

The provisions under which connection points can be classified as market connection points would be extended to allow for secondary settlement arrangements. The draft changes include a new provision to deal with a large customer becoming reclassified as a small customer (clause 2.3.2); premises with a secondary settlement point no longer being eligible to be classified as a secondary settlement point due to a scheduled resource being established at the premises (clause 2.3.3); and a new paragraph allowing a Customer or Integrated Resource Provider (in its capacity as a Market Customer) to classify a secondary settlement point as one of its market connection points (new clause 2.3.4(b1). This would be subject to the principles that a small customer must have the same FRMP at both its connection points and its secondary settlement points and that a secondary settlement point cannot be classified as a market connection point if there is a scheduled resource at the premises (new clauses 2.3.4(b2) and (b3)). Consequential changes to clause 2.3.4 would also be made.

A consequential change would be made to the provision defining a 'qualifying load' for the purposes of the wholesale demand response mechanism to confirm that premises with a secondary settlement point classified as a market connection point are not eligible to provide wholesale demand response (new clause 2.3.6(m)(viii)).

It is intended that where the metering installation for plant has been established as a secondary settlement point and classified as a market connection point, the plant would be eligible to provide market ancillary services in the same way it would be eligible if there were no secondary settlement point. To reflect this, drafting changes would be made to clause 2.3D.1.

Rule 2.10 deals with ceasing to be a registered participant. Where relevant, the provisions will be extended to refer to secondary settlement points (clauses 2.10.1(c) and (c1)). However, the draft rule does not extend the provision under which AEMO can reject a notice from a Market Customer that it wishes to terminate its classification of a connection point as one of its market connection points (clause 2.10.1(d)). Where a FRMP for a secondary settlement point ceases to classify that point (that is, where the child NMI becomes inactive), subtractive metering arrangements will no longer apply and so the energy flows through the point will continue to be settled in the market by the FRMP for the connection point. In practice, this will only affect large customer premises, since

the FRMP must be the same for the connection point and the secondary settlement point for small customer premises.

A consequential change would be made to the interpretation provision in rule 2.12 to recognise small resource secondary settlement points classified under clause 2.2.8.

Some minor drafting changes would be made to chapter 2 for consistency, such as changes to clause 2.3C.2.

D.3.2 Chapter 3 - Market rules

Chapter 3 would be amended so that the term 'market connection point' is used consistently in the settlement provisions. The draft changes are in clauses 3.15.4, 3.15.5, 3.15.6, 3.15.6A, 3.15.8(g), 3.15.8A(b), 3.15.9A(k) and 3.15.10(b). A consequential change would also be made to the clause confirming financial responsibility for market connection points to extend it to financial responsibility for secondary settlement points classified as market connection points (clause 3.15.3).

It is intended that a secondary settlement point would be assigned to the same transmission connection point as the connection point for the premises and similarly, that the distribution loss factor (DLF) for a secondary settlement point will be the same as the DLF for the connection point for the premises. No changes to chapter 3 have been identified for the draft rule to give effect to these principles.

Although the draft determination does not allow for secondary settlement points to be established within a regulated SAPS, the provision dealing with settlement in a regulated SAPS would be amended to replace the term 'connection point' with 'market connection point' to promote consistent drafting (rule 3.21).

The provision dealing with NMI standing data arrangements in Victoria (clause 3.13.12 – Victoria does not apply the NERL) would be amended to recognize that NMI standing data will be required for secondary settlement points since they will be allocated child NMIs to enable subtractive metering arrangements to be implemented.

D.3.3 Chapter 4 - Power system security

In chapter 4, the draft rule amends the provision under which Market Customers having expected peak demands in excess of 10 MW must provide automatic interruptible load (clause 4.3.5). The amendment would provide for the 10 MW threshold to be calculated by reference to load at market connection points, so that, in the case of a large customer with two FRMPs, any load at a secondary settlement point would be attributed to the FRMP for that point rather than the FRMP for the connection point, due to the subtractive metering arrangements.

D.3.4 Chapter 4A - Retailer reliability obligation

Under Parts D and F of this chapter respectively, obligations and compliance for the retailer reliability obligation are determined with reference to consumption at connection points for which an entity is financially responsible. The draft rule amends the provisions to refer to 'market connection points' in place of 'connection point', so that the provisions continue to operate as intended where a Market Customer or Integrated Resource Provider is financially responsible for a secondary settlement point. For Part D the change would be made by amending clause 4A.D.1 and in Part F, the term 'connection point' would be changed to 'market settlement point' throughout. Clause 4A.E.7 would also be amended to refer to market connection points in the provisions deals with adjustments to net contract positions.

D.3.5 Chapter 5A

In chapter 5A, a consequential change would be made to clause 5A.A.4 to reflect that the market connection point for a small generating units or small bidirectional units may not be the connection point to the local network.

D.3.6 Chapters 6 and 6B - Economic regulation of distribution services; retail markets

Clauses 6.20.1(b) and (c1) would be amended and (in chapter 6B) a new clause 6B.A2.1A would be inserted to confirm that network charges should be billed to the primary retailer. Clause 6.20.1(w) would be amended to refer to the new metering installation types being introduced in chapter 7.

D.3.7 Chapter 7 - Metering

Overview

Amendments to chapter 7 would allow a Market Participant to establish one or more secondary settlement points within premises unless the connection point for the premises is for a scheduled resource (including a wholesale demand response unit) or is a connection point in a regulated SAPS. The connection point must also have a type 1, 2, 3, 4 or 9 metering installation.

Amendments to chapter 7 would also introduce metering installation types 8 and 9.

Minor drafting changes would be made throughout the chapter to use consistent drafting when referring to child connection points. The aim is to be clear that child connection points relate to embedded networks and so limit the potential for confusion given that child NMIs, currently only used for child connection points, would be issued for secondary settlement points. Secondary settlement points are not a category of child connection point.

Table D.1: List of changes to chapter 7

Provision	Amendment
Clause 7.1.2	To apply the metering obligations in chapter 7 to secondary settlement points, clause 7.1.2 would be amended to give the term 'connection point' an extended meaning in chapter 7 that includes secondary settlement points.
New clause 7.2.6	Draft new clause 7.2.6 would allow a Market Participant to establish a metering installation situated within the premises of an end user as a secondary settlement point, if the eligibility criteria are met. These criteria are primarily that (1) the connection point for the premises must not be a connection point for a scheduled resource or a connection point in a regulated SAPS and (2) the metering installation must be NER compliant, must not be for a child connection point and (for a large customer) must not be a type 8 metering installation. Type 8 metering installations can only be used at the secondary settlement point of a small customer, due to the lower accuracy requirements.
Clauses 7.3.2(a) and (b)	Clauses 7.3.2(a) and (b) would be amended to recognise that a small customer, or someone on its behalf, may install the type 8 metering installation at a secondary settlement point, such as an EV charger. In that case, the Metering Coordinator would only be required to commission and maintain the meter, but not provide or install it.
Clause 7.6.2(a)	Clause 7.6.2(a) specifies who may appoint a Metering Coordinator.

Provision	Amendment
	Subparagraph (3) allows a large customer to appoint the Metering Coordinator for the connection point for its premises. This would be extended to allow a large customer to appoint the Metering Coordinator for secondary settlement points within its premises.
Clause 7.8.1	Clause 7.8.1 specifies metering installation requirements including (at paragraph (c)) that installation and maintenance of a metering installation must be carried out only by a Metering Provider. This would be subject to a new paragraph (d) that allows a type 8 metering installation to be installed by any person qualified under applicable law to do so. A new paragraph (e) would specify that the Metering Coordinator at a connection point must ensure that there is not a type 8 metering installation at the connection point unless it is a secondary settlement point within the premises of a small customer.
Clause 7.8.2	Clause 7.8.2 deals with metering installation components. Paragraph (a)(1) would be amended to clarify that the information display can either be part of the metering installation or can be made available to the customer by some other means, subject to there being no delay. Paragraphs (a)(3) and (a)(9), relating to electronic data transfer facilities and facilities for storing interval energy data respectively, would be extended to type 8 and 9 meters.
Clause 7.8.2(d)	Clause 7.8.2(d) requires a local network service provider (LNSP) to issue a unique NMI for each metering installation on its network. This would be extended to each metering installation for a secondary settlement point within premises connected to the LNSP's network.
Clause 7.8.2(ea)	Clause 7.8.2(ea) requires an Embedded Network Manager to apply to AEMO for the NMI for metering installations for child connection points. This would be extended to each metering installation for a secondary settlement point within premises connected to the embedded network. Similarly, AEMO's obligation under paragraph (ec) to issue NMIs for child connection points would be amended so it extends to these secondary settlement points.
Clause 7.8.3	Clause 7.8.3 requires new or replacement small customer metering installations to be type 4. Paragraph (a) would be amended to allow a type 4 or type 8 meter to be used for a secondary settlement point within the premises of a small customer. Consequential changes would be made to the cross references in clause 7.8.4.
Clause 7.8.3(b)	Clause 7.8.3(b) requires AEMO to make procedures relating to the minimum services specification and would be amended to refer the new provision at clause S7.5.2 under which AEMO would make procedures to specify the minimum services specification for type 8 and 9 metering installations.
Clause 7.8.10	Clause 7.8.10 deals with metering installation malfunctions. A new paragraph (e) would be added for type 8 metering installations provided by a customer. The FRMP would be required to notify the customer of the malfunction but would not be required to repair the metering installation itself. If the customer does not undertake the repairs within the required time, the secondary settlement point would cease to operate (that is, would be inactive) until the repairs are undertaken. During that time, all flows at the secondary settlement point will be settled through the FRMP for the connection point.

Provision	Amendment
Clause 7.9.6	Clause 7.9.6, which requires AEMO to publish a registration process to facilitate the application of the chapter, would be extended to refer to a process for establishing secondary settlement points.
Clause 7.10.1(a)(2)	The obligations of MDPs under clause 7.10.1(a)(2) relating to the validation and substitution of metering data would be extended to refer to type 8 and 9 metering installations.
Clause 7.10.5(a)(1)	Clause 7.10.5(a)(1), relating to periodic metering data, would be extended to include type 8 and 9 metering installations.
Clause 7.15.3(e)	Clause 7.15.3(e), under which passwords for security controls for energy data are provided to AEMO, would be extended to type 8 and 9 metering installations.
Clause 7.15.4(b)	A change to clause 7.15.4(b) would add a new paragraph (1A) to extend the list of access parties that have access to services provided by a small customer metering installation and metering data to those specified in the minimum services specification for type 8 and type 9 metering installations to be made by AEMO under clause S7.5.2.
New clause 7.15.5(c)(7)	Draft new clause 7.15.5(c)(7) would give an LNSP access to the metering data from secondary settlement points within premises connected to its network.
New clause 7.16.3(c)(6)(v)	Draft new clause 7.16.3(c)(6)(v) would require the metrology procedure to include procedures for the method to be used by a Metering Data Provider to determine the metering data for a secondary settlement point or a child connection point where its connection point or parent connection point has been de-energised or disconnected or the network serving its connection point or parent connection point is experiencing an outage.
Clause 7.16.5(a)(1)(iv)	Clause 7.16.5(a)(1)(iv) would be extended so that the metrology procedure may clarify the operation of the Rules in relation to metrology for a market connection point that is a secondary settlement point. Similarly, clause 7.16.5(a)(2)(iv) would be extended so that the metrology procedure may specify in detail the technical standards for metering of a market connection point that is a secondary settlement point.
Clause 7.16.6(c)	Draft new subparagraph (5A) in clause 7.16.6(c) would require the service level procedures to include the requirements for the assignment of a secondary settlement point within premises to the connection point for the premises. This is to facilitate the use of subtractive metering arrangements.
Clause S7.2.1(d)	Clause S7.2.1(d) would be amended to reflect that customers may provide type 8 metering installations such as EV chargers.
Clause S7.2.2(a) and table S7.2.2.2	Clause S7.2.2(a) and table S7.2.2.2, which deal with categories of registration, would be extended to type 8 and 9 metering installations and to reflect that customers may provide type 8 metering installations such as EV chargers, in which case the Metering Provider will be commissioning and maintaining the installation, but not providing or installing it.
Clause S7.2.3	Clause S7.2.3, which describes the capabilities of Metering Providers for, among others, type 4 metering installations, would be extended to type 8 and 9 metering installations and aligned with the capabilities required for type 4, in particular, at paragraph (f) relating to AS 9000.

Provision	Amendment
Clause S7.2.5	Clause S7.2.5 would be extended to categories of Metering Providers with accreditation for type 8 metering installations so that all Metering Providers for small customer metering installations are subject to the security control management plan and related requirements in paragraph (b).
Clause S7.2.6	Clause S7.2.6 relating to the capabilities of Accredited Service Providers would be extended to measuring installation types 8 and 9.
Table S7.3.2.1	Table S7.3.2.1 sets out the categories of registration for accreditation by metering installation type. The table would be extended to type 8 and 9 metering installations and the new registration categories 8M and 9M.
Clause S7.4.1	Clause S7.4.1 would be amended to incorporate provisions proposed in the rule change request. These deal with the use of extended range current transformers and the use of a generic design to demonstrate accuracy for type 4, 5 and 6 metering installations. The rule change request indicates that the changes in paragraph (b) are for clarification purposes and were recommended as part of a Meter Testing Review undertaken by AEMO in consultation with Metering Provider and Responsible Person representatives. The rule change request also indicates that new paragraph (d) is for clarification purposes and results from recommendations of the Metering Working Group, chaired by AEMO and resourced with representatives of Metering Providers and Responsible Persons. The text that is currently presented in Item 6 and Notes to the bottom of the tables in S7.4.3 would be repositioned as a lead-in to the clause to aid clarity. Table S7.4.3.1 would also be amended to remove the column 'maximum allowable overall error' and the related item in the Notes because the same material is set out in other tables in S7.4.3.
Clause S7.4.3	New paragraph (e) in the lead in to S7.4.3 would clarify that where subtractive metering arrangements are used (that is, parent and child NMIs used for secondary settlement point arrangements or embedded networks with child connection points) the annual energy throughput is the total throughput for the metering installation not the net throughput after subtraction of the child NMI metering data.
Table S7.4.3.1	Table S7.4.3.1 deals with the volume limits by metering installation types, the minimum acceptable class or standard of components and allowable clock errors. The table is supplemented by a set of notes set out as numbered 'items'. New rows would be added to the table to specify the requirements relating to type 8 and 9 metering installations. Consequential changes would be made to the notes in items 1 and 6. Item 2a would be amended to allow AEMO to relax the clock error for types 8 and 9 metering installations in the metrology procedure, as it can currently do for types 4 and 4A. A new item 7 would allow the maximum allowable error of a type 8 or 9 metering installation to be relaxed in the metrology procedure. Item 8, relating it to type 9 metering installations, would note that these may have a central management system.
Tables S7.4.3.2	Tables S7.4.3.2 to S7.4.3.6 specify detailed accuracy requirements by metering

Provision	Amendment
to S7.4.3.6	installation type. These would be corrected as proposed by AEMO in the rule change request. In addition, table S7.4.3.4 would be extended to type 9 metering installations. A new table S7.4.3.7 would be inserted to specify the overall accuracy requirements for type 8 metering installations. The table would be based on table S7.4.3.4 (which applies to type 4 category 4S and type 9 metering installations) except that the overall accuracy requirement at 100% of rated load would be 2%.
Table S7.4.4	Table S7.4.4 would be amended to specify that check metering is not required for type 8 or 9 metering installations.
Schedule S7.5	The schedule would be amended so that the minimum services specification in table S7.5.1.1 does not apply to type 8 or 9 metering installations. Instead, a new clause S7.5.2 would be inserted to allow AEMO to establish, maintain and publish procedures that set out each service required to be provided by type 8 and 9 metering installations, subject to the considerations in the clause. The new clause would also specify when a type 8 or type 9 metering installation meets the minimum services specification, consistent with clause S7.5.1.
Table S7.5.1.1	Table S7.5.1.1 sets out services and access parties for the services and metering data (references in clause 7.15.4). The table would be amended to add the LNSP as an access party for the remote on-demand meter read service at item (c) and the remote scheduled meter read service at item (d), in relation to a secondary settlement point located within premises connected to its network.
Tables S7.6.1.2 and S7.6.1.3	**Schedule S7.6** deals with inspection and testing requirements. Tables S7.6.1.2 and S7.6.1.3 would be amended to clarify and correct the tables as requested by AEMO in the rule change request and to extend the tables to the new metering installation types.

D.3.8 Chapter 8 - Administrative functions

A consequential change to clause 8.2.1(h)(10) would be made to clarify that the rules dispute framework in rule 8.2 does not apply to a decision by AEMO under clause 7.2.1(b) to refuse to permit a Market Participant to participate in the market in respect of a secondary settlement point.

D.3.9 Chapter 10 - Glossary

Table D.2: List of changes to chapter 10

Definition	Amendment
central management system	A new defined term 'central management system' would be included to allow for metering installations that comprise many devices over an area that are then aggregated into a single installation (ie type 9).
connection point	The term 'connection point' would be amended by adding a note referring to the extended meaning it has in chapter 7.

Definition	Amendment
interval energy data	The term 'interval energy data' would be amended to refer to type 8 or 9 metering installations which are assumed to be capable of providing data in the same manner as types 1, 2 and 3 metering installations.
market connection point	The term 'market connection point' would be amended to include secondary settlement points classified as such under chapter 2.
metering installation	The term 'metering installation' would be amended to include reference to central management systems and associated components. The second 'note' under the definition would be deleted; it is out of date because the term 'metering installation' now encompass revenue metering points and check metering points.
new connection	A drafting change to the term 'new connection' would include reference to its use in chapter 7.
secondary settlement point	A new definition 'secondary settlement point' would be included.
Small Resource Aggregator	The definition of 'Small Resource Aggregator' would be amended to reflect that a small resource secondary settlement point can be classified as a market connection point under clause 2.8.8.
small resource secondary settlement point	A new defined term 'small resource secondary settlement point' would be included to refer to secondary settlement points for small generating units or small bidirectional units, where the only supply to the point is for use by the small bidirectional unit or is auxiliary load. This is intended to reflect the definition of 'small resource connection point'.
spot price	The term 'spot price' would be amended to remove an out of date reference to the price at a connection point, since clause 3.9.2 only refers to determination of the spot price at a regional reference node.
SRA customer	The term 'SRA customer' would be amended to include a reference to small resource secondary settlement points, to reflect the new framework.
In addition to the changes mentioned above, the following defined terms would be amended by including a reference to secondary settlement points: active energy, Customer, Incoming Retailer, Market Customer, Market Settlement and Transfer Solution Procedures (MSATS), NMI standing data, Non-Registered Customer and small customer metering installation.	

D.4 NERR key concepts

The draft changes to the NERR would clarify how the rules apply where a secondary settlement point has been established at a customer's premises. The changes reflect that small customers will have the same FRMP for both the connection point and the secondary settlement point, but a large customer may have different FRMPs for each point.

A new term 'secondary settlement arrangement' would be introduced into the rules to refer to premises where a second settlement point has been classified as a market connection point. The

new term 'primary retailer' would be introduced to refer to the retailer that is financially responsible for the connection point – except in the case of large electricity customers, this will be the same as the retailer for the premises. The new term 'secondary meter' would be introduced to refer to the metering installation at a secondary settlement point. The term 'secondary settlement point' would have the same meaning as in the NER.

The changes would reflect that the metering installation for a secondary settlement point may have been provided by or on behalf of the customer (such as an EV charger) and retailers would not be entitled to replace those metering installations.

The primary retailer would have rights of access to the primary meter (as at present) and to metering data from any secondary meter if that will be used for the customer's tariff. There would be no right to de-energise for denying access to a secondary meter or its data. Instead, the retailer could move the customer to a tariff that does not require the metering data from the secondary meter.

The changes would clarify how the rights and obligations of retailers apply with respect to secondary settlement points and the meters and metering data from secondary settlement points. The draft rule reflects that these need not be the same as retailers' rights and obligations with respect to the connection point for premises, since the disconnection or de-energisation of a secondary settlement point can occur without loss of supply to the premises as a whole and if the customer fails to provide access to the secondary settlement point or the related metering data, there is no need to de-energise or disconnect premises. Instead, a small customer's retailer could transfer the customer to a tariff that does not use data from their secondary settlement point.

The draft amendments would however not allow de-energisation or disconnection of secondary settlement points at premises with life support equipment.

The changes would clarify how the rights and obligations of distributors apply with respect to secondary settlement points. With some exceptions, the distributor would only be required to give notice to the primary retailer or accept requests for reclassification or de-energisation from the primary retailer.

The standard retail contract would be amended to allow for the possibility that a retailer's standard tariffs may include one or more that recognises CER benefits.

D.4.1 Draft changes to the NERR

Table D.3: Outline of NERR changes in draft retail rule

Rule 3	**Definitions:** New terms 'primary retailer', 'secondary meter', 'secondary settlement point' and 'secondary settlement arrangement' would be included in rule 3.
Rules 5 to 11	**Classification:** Rules 5 to 10 would be amended to reflect the principle that a customer's primary retailer deals with classification and reclassification. Draft new rule 5(6)(b) would clarify that where premises are aggregated, there can be a different FRMP for a secondary settlement point at any of those premises. A consequential change would be made to rule 11(4)(b) for consistency and to clarify that for classification purpose, a distributor can use estimates from

	each retailer (in respect of its own meter), not just one of them.
Rules 29 and 37	**Bills**: Rules 29(5) and (5A) and rule 37(2) would be amended to reflect that more than one meter may be used to work out a bill. Rule 35(1) would be amended to reflect that the bill may relate to the premises and SSPs within the premises.
Rules 59B and 59C	**Retailer planned interruptions and de-energisation requests:** Rules 59B and 59C would be amended so that the 'retailer planned interruptions' obligations would not apply where the interruption is only to supply at a secondary settlement point, except that for a life support customer, the obligations would extend to all secondary settlement points within the premises. Similarly, a retailer would not be permitted to arrange for the de-energisation of a secondary settlement point within a customer's premises where the premises are registered as having life support equipment.
Rule 64	**Energy marketing:** Rule 64(1)(a2) would be amended so that the information provided by a retailer to a prospective customer would need to include information about terms and conditions associated with a proposed secondary settlement arrangement, including prices, charges and benefits and any requirements for operational control by the retailer or the distributor of equipment within the customer's premises.
	Retail support arrangements / shared customers:
Rule 79	Rule 79(3) would be amended to clarify that only a customer's primary retailer can apply for customer connection services.
Rule 82	Rule 84(2) would be amended to clarify that only the primary retailer has the obligation to cooperate with the distributor in relation to GSL payments.
Rule 93	A note would be added under rule 93(1) to confirm that a customer with a secondary retailer will be a 'shared customer' of that retailer and the distributor. This flows from the defined term in the NERL and would mean that except where otherwise specified, the obligations in Part 5 apply (separately) to ensure cooperation between the distributor and the primary retailer and the distributor and the secondary retailer.
Rule 99	Rule 99 would be amended so that a distributor would only be required to notify the primary retailer of distributor planned interruptions or unplanned interruptions, and rule 99A would be amended so that only the primary retailer would need to tell the distributor of retailer planned interruptions.
Rule 100	Rule 100 would be amended so that the distributor only has to notify the customer's primary retailer of unplanned interruptions. The obligation in rule 100(3) for retailers to refer a customer enquiry to the distributor would apply to both retailers.
Rule 101	Rule 101 would be amended so that if a shared customer makes an enquiry or complaint to the distributor about an issue relating to the sale of energy and there is a secondary settlement arrangement, the distributor must tell both retailers. Only the retailer the subject of the complaint or enquiry would be required to resolve it.

Rule 102	Rule 102(2) would be amended so that only a request from a primary retailer requires a distributor to provide information about a shared customer's energy consumption.
Rule 104	Rule 104 would be amended to give effect to the principle that only the primary retailer has to give or be given notice of de-energisation to or by the distributor.
Rule 106A	Rule 106A would be amended to give effect to the principle that only the primary retailer has to give or be given notice of re-energisation and to reflect (in subrule (6)) that only a primary retailer can request de-energisation of premises. However, rule 106A(3) would not be amended, so that both the primary and secondary retailer are subject to the requirement that a retailer must not arrange re-energisation of a customer's electricity supply by a person other than the distributor if the premises were de-energised by the distributor.
Part 6 (rules 107 to 122)	**De-energisation of premises:** Part 6 (rules 107 to 122) deals with de-energisation of premises. Few changes would be made on the basis that the relevant provisions work as intended given that the Part applies only to small customers, with the exception of rules 119 and 120(1)(a), (2) and (3)). Rule 113(1) would be amended so that there is no right to de-energise for denying access to a secondary meter. Rule 113(2) would amended so that there is no right to de-energise the premises if a customer does not provide the retailer or its representatives safe access to the customer's premises in accordance with any requirement under the energy laws or otherwise for the purpose of testing etc a secondary meter or replacing etc a secondary meter. Rule 116 would be amended with the addition of a new subrule (1A) to the effect that a retailer must not arrange for the de-energisation of a secondary settlement point within a customer's premises where the premises of a life support customer.
Rules 129, 132 and 147	**Prepayment meter systems:** The prepayment meter system rules would extend to secondary settlement points. Rule 129(2) would be amended to give effect to the principle that prepayment meters can have remote displays. Rule 132(1) would be amended to give effect to the principle that the energy consumption information etc to be provided by the retailer should be for the supply to which the customer's prepayment meter system applies. Rule 147(1) would be amended to ensure this provision (which deals with deemed customer retailer arrangements for move-in or carry-over customers) applies where a prepayment meter is at a secondary settlement point.
Rule 151	**Exempt selling regime:** Rule 151(1A) would be amended to state that the classes of persons in respect of whom an exemption is registrable may include persons (not being retailers) that are financially responsible for secondary settlement points within the premises of large customers.
Rule 167	**AER retailer performance reports:** Rule 167(3) would be amended to require the AER retailer performance report to include information by reference to

	supply to premises with and without secondary settlement arrangements.
Schedule 1, Model T&C for standard retail contracts	
Clause 4.3	Clause 4.3(b) provides that when vacating premises, the retailer must use its best endeavours to arrange for the reading of the meters. This would be amended to be clear that this extends only to the primary meter (ie the 'meter for the premises').
Clause 5.1	In clause 5.1(a), the references to the retailer's obligation to provide a meter would be amended to refer to the provision, installation and maintenance of the meter for the premises. Whether the retailer has to provide the meter for a secondary settlement point would depend on the equipment at the point, for example an EV charger owned by the customer may incorporate its own meter.
Clause 6.3	Clause 6.3(d)(iii) explains the retailer's obligations to provide notice of supply interruptions to premises with life support equipment and would be amended to align with changes to the NERR that extend the requirements to de-energisation of any secondary settlement point.
Clause 8.3	Clause 8.3 explains that the customer can be transferred to a different tariff if the customer ceases to be eligible for its existing tariff due to a change in use of energy. This would be amended to extend it to 'other change to the supply arrangements' at the premises to accommodate changes such as removing or disabling an EV charger that had previously been an SSP.
New clause 8.3A	Draft new clause 8.3A would explain that if the customer has provided the meter at a secondary settlement point and the meter no longer operates in accordance with the requirements of the energy laws, the retailer could transfer the customer to a new tariff.
Clause 9.3	Clause 9.3 deals with estimates of energy usage. It would be extended to refer to later collection of metering data, as well as meter reads.
Clause 11	Clause 11 deals with meters. Subclause (a)(1) would be amended to clarify the right to access to maintain etc meters applies only where required to meet obligations under energy laws. Subclause 11(d) would be amended to clarify that the retailer would only replace meters that it is responsible for providing under energy laws.
Schedule 2, Model T&C for deemed standard connection contracts	
Clause 9.1	Clause 9.1(a) would be amended to clarify that the rights of access described in the clause only operate to the extent permitted under the energy laws.

E Summary of other issues raised in submissions and additional consultation

Table E.1: Summary of other issues raised in submissions on the directions paper and additional consultation

Stakeholder	Issue	Response
AEMO, p. 9 and Energy Queensland Limited, p. 1.	AEMO, supported by Energy Queensland Limited, suggested that metering amendments be considered for primary customer meters in regulated stand alone power systems (SAPS). AEMO noted that "It is typical for the location of SAPS to be in areas that are remote and rural, and typical communications networks such as 3, 4 and 5G access is often restricted or inconsistent. AEMO noted the cost of metering for these connection points under existing requirements given that, due to low connectivity, expensive high-gain antennas or remote communication networks like the Starlink satellite network are required. AEMO suggested allowing the use of the new meter types proposed for secondary settlement points at SAPS primary connection points with alternative approaches for the management of metering data delivery and communications, namely without the same remote communication requirement. Energy Queensland Limited reiterated this noting that, for SAPS, its preference 'is to allow the Metering Data Provider to provide substituted metering data for SAPS generation in lieu of a collection process in its entirety (including avoiding establishment of remote comms)'.	The Commission has determined that metering arrangements for SAPS are out of scope for this rule change. This is because remote communications is at the core of the new meter types so any lessening of remote communications requirements for the new meter types would not be appropriate for the purposes they are intended to be used under this draft rule. In relation to data substitution for SAPS metering arrangements, the Commission considers that this would be best considered as a part of a distinct rule change on SAPS or microgrids rather than as part of this rule change process.
Energy Queensland, p.2	In discussing implementation issues, Energy Queensland proposed an alternative model. Specifically, "Energy Queensland suggests that an alternative pathway for separately identifying and managing flexible CER could be via dynamic connections (also known as flexible exports in South Australia). Dynamic connections and other DNSP equivalents are deployed using CSIP-AUS, which can provide another source of disaggregated CER monitoring data".	In its decision to progress with secondary settlement points and secondary metering arrangements, the Commission selected the option that not only was the most efficient amongst those evaluated but also offered consumers a range of opportunities to optimise their CER (access to FCAS markets, wholesale market and network services). Finally, we note the ongoing

Stakeholder	Issue	Response
		AER work on the Review of regulatory framework for flexible export limit implementation. This review is best placed to incorporate implementation considerations around this particular instrument of network management.
Rheem, p. 7, SwitchDin, p. 4.	Rheem raised concerns that this rule change would involuntarily exacerbate the existing issue of CER being non interoperable, with non-interoperable sub-metering risking consumer lock-in in situations restricting customer churn. Specifically, in its submission, Rheem mentioned "situations where disparate control of CER assets on the same site due to proprietary control and or bespoke wiring arrangements can lead to CER assets "fighting" each other causing consumer financial loss and negating contracted responses for grid services such as FCAS and Minimum / Peak demand abatement". SwitchDin echoed Rheem's call to address interoperability: "We note that the Final Report of the AEMC Review of the Regulatory Framework for Metering Services recommends that an enabling framework for consumer access to real-time smart meter data should consider interoperability as a matter of performance. SwitchDin supports this approach. It requires the consideration of the performance of the primary meter and secondary meters together, as a system."	Whilst the Commission recognises the importance that interoperability plays in CER coordination and orchestration, we highlight that communication protocols and aspects of CER controls are out of scope of this rule change and may not be subject to AEMC rule-making powers. The ESB work on interoperability is best placed to progress this issue. We note the proposal for a rule change on access to real-time data. Further, Commission comments are provided in Chapter four for this issue.
SwitchDin, p.5. Master Electricians Australia, p.5	In our Directions Paper we asked stakeholders what changes we could make to the NER and NERR to assist in overcoming the current barriers to the second connection point. In response to this question, SwitchDin answered "We urge the AEMC to review each jurisdiction's Service and Installation Rules for CER and EV chargers and the potential benefits of harmonising them.". Answering the same question, Master Electricians Australia advocated nationally harmonised guidelines regarding the installation of second settlement points, adding "the current lack of commentary within the Installation Rules could leave distributors averse to such installation".	The Commission is aware that the current inconsistencies between jurisdictional service and installation rules may affect eligibility and outcomes of connection requests. However, we note that this task is included in the National Electric Vehicle Strategy, where officials will work with DNSPs to consider how current jurisdictional service and installation rules can be

Stakeholder	Issue	Response
		streamlined. We consider this work a more suitable forum to deal with issues around jurisdictional network connection arrangements.
Tim Ryan	One stakeholder raised the question of how virtual or mobile NMIs could be incorporated into the new metering types/arrangements. This relates to the allocation of NMIs to vehicles for the purpose of settling electricity consumed through public charging via a customer's retailer.	The Commission considers that this proposal requires more detailed analysis, which is currently out of the scope of this rule change.

Defined terms and Abbreviations

Defined terms

Consumer energy resources (CER): Flexible load and generation at consumers' premises. CER assets include rooftop solar panels, batteries, home, and business energy management systems, pool pumps, and electric vehicles (and charging), as well as 'newer smart devices' such as hot water systems and traditional controlled hot water. For large customers, these can include heating and air conditioning (HVAC), on-site refrigeration, and on-site backup generation. We also include distributed energy resources (DER) such as community batteries for the purpose of this paper.

Flexible trading of CER: Consumers can take up different product and service offers for their CER. For the industry, it means consumer resources and consumption can be better enabled to use in the wholesale energy and ancillary services market and for network services.

Connection point: Connection point is used throughout the rules (and in the electricity sector) to mean the point which is both:

(a) the physical point of connection between the consumer's premises and the distributor's network, and

(b) the point at which energy is measured for market settlement.

Secondary settlement point: Points at a consumer's premises that would be behind the existing connection point (referred to as the primary connection point), which would have a National Metering Identifier attached to them, and would be able to be separately identified in AEMO systems. This is a new term established in the draft electricity rule.

Market connection point: Refers to connection points for which a Market Participant is financially responsible. The draft electricity rule would amend this definition to allow a secondary settlement point (including a small resource secondary settlement point) to be classified as a 'market connection point'.

National Metering Identifier (NMI): Each metering installation associated with a connection point (or in the case of this paper, settlement point) is identified in MSATS with a unique NMI. An NMI is generally generated by the local distribution network.

Financially Responsible Market Participant (FRMP): Entities (e.g. retailers or aggregators) that a consumer would contract with for services provided at settlement points, where those services are traded in the wholesale markets. A FRMP does not necessarily have to be an authorised energy retailer (this will depend on whether it sells electricity to its customers), but, as defined in the NER, must be registered by AEMO to be able to participate in wholesale markets.

Small Generation Aggregator (SGA): A registered participant role within the NEM. An SGA supplies electricity from one or more small generating units to the NEM and is financially responsible for the electricity provided. From 3 June 2024, this role will become known as a Small Resource Aggregator.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CER	Consumer energy resources (see above)
CMS	Central Management System
DNSP	Distribution network service provider
EAP	Energy Advisory Panel (replacing the ESB)

ESB	Energy Security Board
EVSE	Electric vehicle supply equipment
FCAS	Frequency control ancillary services
FRMP	Financially responsible market participant (see above)
FTM2	Flexible trading model 2, AEMO's term in the rule change request for its proposed approach to flexible trading (see above)
IPWEA	Institute of Public Works Engineering Australasia
LNSP	Local network service provider
MC	Metering coordinator
MDP	Metering data provider
MEFM	Minor energy flow meter
MP	Metering provider
MSATS	Market Settlement and Transfer Solutions
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERO	National Energy Retail Objective
NERR	National Energy Retail Rules
NMA	*National Measurement Act 1960* (Cth)
NMI	National metering identifier (see above)
NPV	Net Present Value
NT Act	*National Electricity (Northern Territory) (National Uniform Legislation) Act 2015*
SGA	Small generation aggregator (see above)