AEMC

RULE

Australian Energy Market Commission

RULE DETERMINATION

NATIONAL ELECTRICITY AMENDMENT (INTEGRATING ENERGY STORAGE SYSTEMS INTO THE NEM) RULE 2021

PROPONENT

Australian Energy Market Operator

2 DECEMBER 2021

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Energy Ministers' Meeting (formerly the Council of Australian Governments Energy Council). We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the Energy Ministers' Meeting.

SUMMARY

1 As our electricity system transitions to a net zero system with very high proportions of variable renewable energy, energy storage is playing an increasingly important role in the national electricity market (NEM). The regulatory framework needs to facilitate this shift. The Australian Energy Market Commission (Commission or AEMC) has made a final determination and rule as a step to achieving this goal. The final rule, which is a more preferable final rule, introduces a new participant category, the Integrated Resource Provider (IRP), that will facilitate the efficient entry and operation of storage and hybrid facilities in a flexible and technology-neutral way.

2 The final rule also makes changes to the recovery of the non-energy costs framework that recognise many participants now have two-way energy flows. This change will better reflect how participants use and benefit from the non-energy services the Australian Energy Market Operator (AEMO) procures to operate the power system in a safe, secure and reliable manner. A range of other changes are also made throughout the National Electricity Rules (NER) to better integrate storage and hybrid facilities into the NEM, and to update and streamline the NER.

3 The final rule has been considered alongside the Energy Security Board's (ESB) two-sided market work which is looking at simplifying the participation framework more holistically, with a move towards a services-based model and a single trader participant category in the future. The changes made in this final rule solve the immediate issues relating to integrating storage that were raised by AEMO, and take important steps towards the two-sided market future being developed by the Energy Security Board.

AEMO's rule change request

4 On 23 August 2019, AEMO submitted a rule change request to the Commission seeking to:

- amend the NER to define storage
- introduce a new participant category, the bi-directional resource provider
- apply storage-specific obligations.

5 AEMO's proposal was intended to remove barriers and better facilitate the integration of storage and hybrid facilities into the NEM.

A future-focused framework for a changing market

6 The market is moving towards a future that will be increasingly reliant on storage to firm up the expanding volume of renewable energy and deliver the growing need for critical system security services as thermal generators retire. While the existing storage capacity in the NEM is relatively small, it is forecast to increase significantly over the coming years. This rule change is critical not only to resolve immediate issues but also to create a framework that facilitates innovation to supply energy at the lowest cost to meet the long-term interests of energy consumers.

7 In the short-term, the final decision removes barriers to storage and hybrid systems participating in the market. This will primarily be achieved by introducing a new technology neutral participant category to accommodate participants with bi-directional energy flows. This new category allows aggregators to classify small storage units and provide energy and ancillary services. The reforms also level the playing field for all participants in relation to the recovery of non-energy costs. This will remove distortions in the market that would otherwise become greater and increasingly drive inefficient behaviour and outcomes.

8 The changes made in this final rule open the market up to greater participation by both small and large batteries. Greater participation will likely lead to lower prices for consumers through increased competition to supply energy and ancillary services. It will also allow customers with generators or storage units (e.g. home batteries) to achieve increased returns from these devices through access to a greater range of services and value streams.

9 In the longer term, these changes:

- will remove barriers to entry for more flexible resources and services in the future power system, including providing flexibility to accommodate new forms of participants such as small and large storage units embedded into hybrid systems as well as standalone
- will facilitate innovative business models that deliver efficient market solutions to address the needs of the transitioning system
- provide a market signal to investors that the new category is being set up as the future universal category outlined in the ESB's post-2025 work
- are the first steps along the path towards a two-sided market in the NEM where technical obligations are placed on services not participant categories.

The Commission has made changes to better integrate storage

Registration and participation

10 The Commission's final determination creates a new technology neutral participant category, the IRP. It accommodates a variety of participants with bi-directional energy flows that may offer and consume energy and ancillary services. This includes grid-scale storage, hybrids and aggregators of small generation and storage units.

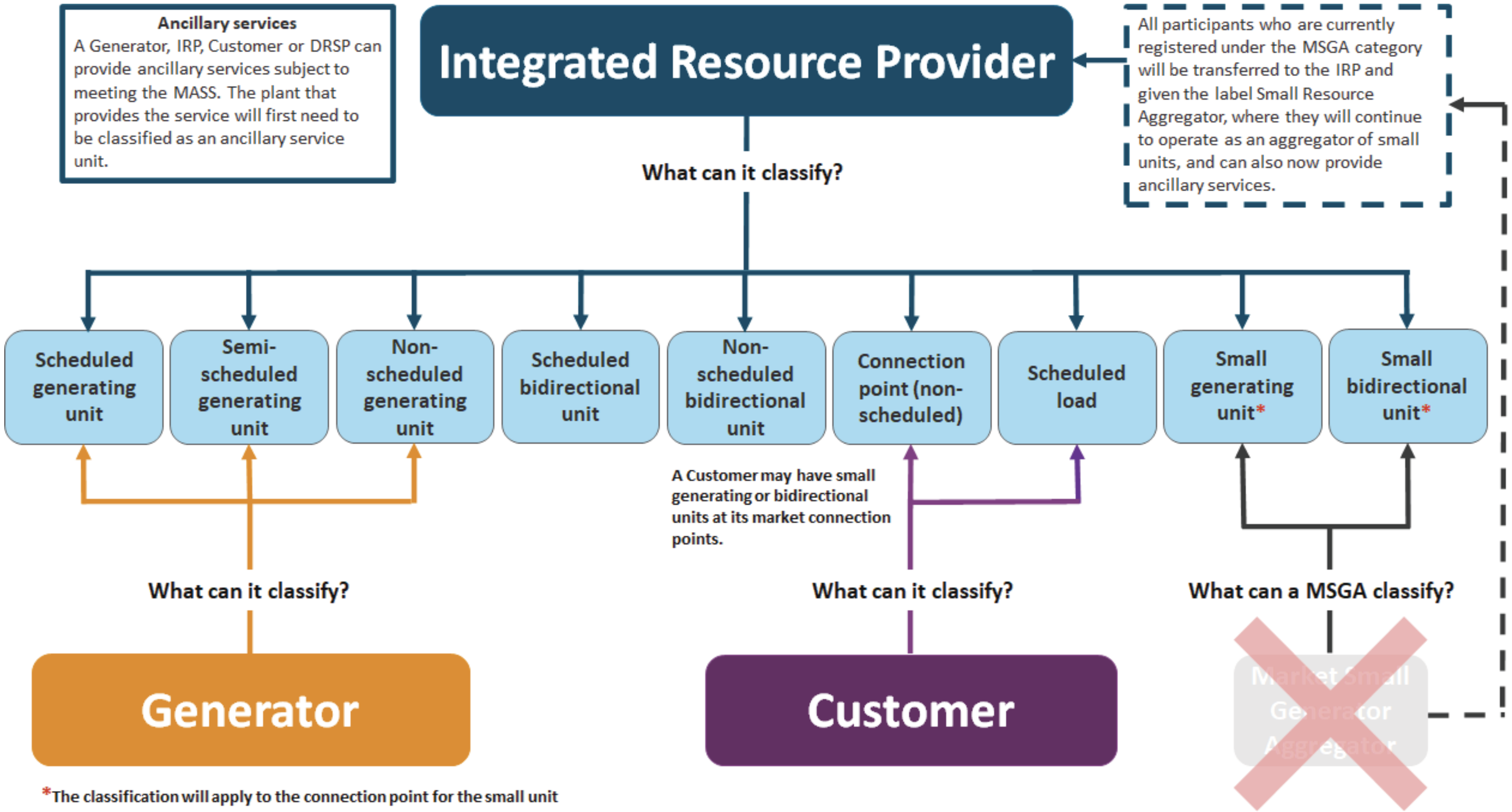
11 Introducing the IRP registration category addresses issues raised by AEMO and stakeholders by:

- enabling storage and hybrids to register and participate in a single registration category rather than under two different categories. Figure 2 provides an overview of the classifications and services that can be provided by the new IRP category.
- providing clarity for scheduling obligations that apply to different configurations of hybrid systems, including DC-coupled systems with different technologies behind a single inverter, who will have flexibility to choose whether those technologies are scheduled or semi-scheduled
- providing aggregated dispatch conformance for hybrid systems, subject to system security limitations

- enabling batteries to participate in dispatch as a single bidirectional unit
- clarifying that the approach to performance standards that are set and measured at the connection point will apply for grid-scale storage units, including where part of a hybrid
- transferring existing small generation aggregators to the new category
- enabling new aggregators of small generating units and/or storage units to register in this new category or as Market Customers
- enabling aggregators registered in the new category to provide market ancillary services from generation and load.

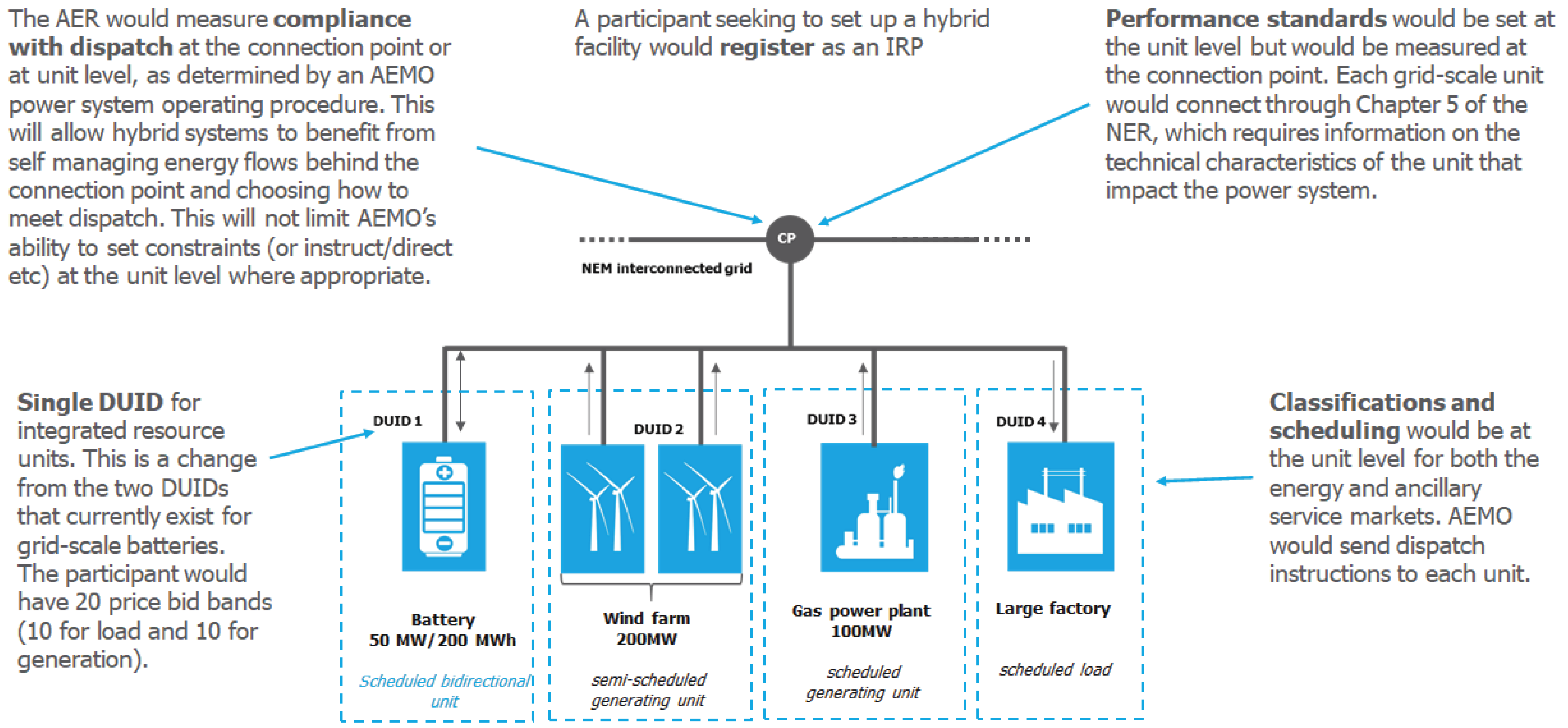
12 Figure 1 shows the range of classifications and services that can be provided by the IRP. It is optional for Market Customers and Generators to join the IRP category. Figure 2 outlines a number of the key design features for hybrid systems.

Figure 1: Classifications and services that can be provided by Market Participants



*The classification will apply to the connection point for the small unit

Figure 2: An example of a hybrid facility registered as an IRP



This diagram is an example of a potential hybrid facility. A hybrid facility could vary in the number and type of units behind its connection point.

Recovery of non-energy costs

1 The Commission's final determination amends the framework to recover non-energy costs based on a participant's consumed and sent out energy irrespective of the participant category in which it is registered. Consumed and sent out energy will be measured separately for all market participants and not netted at the connection point, or among a market participant's connection points.

2 This change provides a number of benefits. It:

- **Aligns cost recovery with the principle of beneficiary and causer pays** as the cost of services to support the power system will be funded proportionally from those who benefit from or cause the need for them.
- **Provides incentives for more efficient behaviour** by charging participants based on an accurate accounting of their share of gross load or generation, where relevant. This may provide stronger incentives for these participants, or their customers, to mitigate this cost by providing the service themselves, where possible. Other participants will see reduced costs, lowering their costs of participating in the market.
- **Aligns with a service-based approach** by assigning costs to participants based on the service they receive from the market, and is an important step towards a more efficient two-sided market.

3 In addition, the final rule provides a longer term solution to the settlement and equity issues raised by AEMO and Iberdrola (then Infigen) on settlement at low and negative demand conditions.

The final rule maintains the existing framework for network charges and should not impact existing connection agreements

4 The Commission's final decision maintains the existing framework to allow transmission-connected storage to choose between connecting under a negotiated agreement at a negotiated price, or the prescribed service and corresponding prescribed transmission use of system (TUOS) charge. The Commission does not consider that storage should automatically pay network charges, including the prescribed TUOS charge. Rather, storage participants can choose the service they need and whether they go through the process of obtaining a negotiated or prescribed shared transmission service. New transmission–connected storage participants will be able to negotiate arrangements with Transmission Network Service Providers (TNSPs) in the same way existing storage participants have. The Commission notes that, in accordance with the NER, TNSPs will negotiate price and service levels that are consistent with those that have been negotiated for other transmission customers receiving the same service, which in the case of existing storage participants could be zero or close to zero.

5 Under the decision relating to registration, existing storage participants will be transferred to the IRP category with a quick and straightforward process. AEMO will not charge fees for this

re-registration and reclassification, and will not reopen existing performance standards or re-examine an existing unit's compliance with its performance standards.

6 The Commission's intent is that the shift to the new category would not change existing connection agreements, including existing performance standards, network services and network charging arrangements. This is specified in clauses 11.145.5 and 11.145.14. The Commission understands that many storage proponents have negotiated very low or zero network charges with their TNSP, and does not consider any changes made in this rule change should alter those agreed charges.

7 New storage participants who choose to connect to the distribution network will receive a direct control service tariff or a storage tariff trial option, where offered.

Further work is needed to investigate network charging issues for storage and other participants

8 The Commission notes that the existing rules relating to prescribed transmission service tariffs were not designed for loads like storage that can respond to dynamic price signals and can be controlled to minimise their impact on, or indeed reduce, network congestion. The existing negotiated services framework can accommodate these types of loads without imposing prescribed TUOS charges.

9 The Commission considers there are broader issues that would need to be considered in relation to prescribed TUOS charges and this rule change is not the appropriate avenue to address these substantial and complex issues. Further work is needed on how network prices are set for storage and other large flexible loads (e.g. hydrogen) to provide them with efficient operational and investment incentives to support the energy market as it transitions to more renewables. The Commission anticipates a separate rule change request from interested participants that would allow us to consider these issues in more depth. The Commission will prioritise any such rule change request in the 2022-23 financial year.

Costs, benefits and implementation

Costs and benefits

10 The Commission notes the final rule will require changes to a number of AEMO systems, procedures and processes. AEMO has provided an estimated range of upfront costs for these changes of $20 million to $29 million. This includes:

- $8 million to $10 million for the introduction of a new bidirectional participant category
- $5 million to $7 million for changes to the recovery of non-energy costs framework,
- the remaining $6 million to $11.7 million for a number of additional changes made to AEMO's systems, procedures and processes that will better integrated storage, including allowing DC coupled systems and aggregators of small generating and storage units to provide ancillary services.

11 The Commission considers that, over time, the extensive benefits of the final decision are likely to far outweigh the costs of the reforms and therefore the final determination promotes

the National Electricity Objective. In particular, the Commission has considered solutions that keep costs as low as possible while maximising the long term benefits for the market and consumers, and notes the final rule:

- implements enduring changes that, as part of this reform, set up some systems more efficiently for the flexibility needed to implement further post-2025 reforms, where future changes that fall out of the ESB work will be simpler and cheaper to implement
- avoids making modifications to existing categories that would:
  - not necessarily be materially cheaper,
  - not realise the benefits of a simple and clear framework created through a single category
  - likely need to be unwound as a result of future ESB reforms.

Implementation

12 The majority of changes made by the final rule will come into effect on 3 June 2024. There are two changes that will come in earlier on 31 March 2023:

- Allowing aggregators of small generating and storage units to provide ancillary services.
- Allowing hybrid systems to use aggregate dispatch conformance. While the IRP category will not be available until June 2024, participants will still be able to register hybrid systems in the existing categories, for example as generators and market customers, and classify their units under the existing framework.

13 The Commission notes stakeholders considered some changes should be prioritised and brought forward as soon as possible. However, AEMO considered that 18 months would be insufficient for it to implement all the changes set out in the draft determination and has provided more detailed information recommending an implementation timeline of 30 months.[1] AEMO's reasons for needing a longer implementation timeline are primarily due to:

- **Concurrent projects**. The existing pipeline of work for retail and metering systems, namely Global Settlements, is the key constraint driving the timing.
- **Project dependencies**. AEMO has identified a number of direct dependencies that need to be considered when planning the final rule implementation, including the Short-Term Projected Assessment of System Adequacy (STPASA) redevelopment project, as well other projects on flexible trading arrangements, scheduled lite, Fast Frequency Response and other ESB initiatives.

14 The Commission notes that while ideally the final rule would be implemented before June 2024, it recognises the wide range of regulatory changes that are happening and dependencies between current and future reforms. The Commission appreciates AEMO's work on the proposed implementation plan and notes that it is important for the final rule to be implemented thoughtfully and with consideration of the broader regulatory reform road map, on which the Commission has been working closely with AEMO.

1 This is set out in the letter from AEMO dated [19] November 2021, published with this final determination.

A guide to this determination

15 This final determination have various levels of detail on the final decisions and rules:

- Chapters 1 and 2 provide a summary of the rule change request and process, and the Commission's final decisions.
- Appendices A to D outline more detail on stakeholder views, and the Commission's analysis and final decisions on:
  - registration and participation
  - non-energy cost recovery
  - network use of system charges
  - Other issues raised in the rule change request
- Appendix F provides a summary of the rule
- Appendix G provides a description of changes from draft rule to final rule.

A summary of the key parts of the final determination

Table 1: A guide to key parts of the final determination

TOPIC	FINAL DECISION	RATIONALE
Registration and participation	The changes to registration and participation include: • a new IRP participant category • treating storage as a single unit for the purposes of dispatch and increasing the number of bid bands to 20 (10 for both load and generation) • allowing flexibility for DC coupled systems to register and participate as scheduled, semi-scheduled or both • moving aggregators of small units and existing small generation aggregators to the IRP and allowing them to participate in the ancillary services market.	The final decision combines a number of reforms that simplify the registration process for storage participants and allows hybrid facilities a clear avenue to join the NEM. It: • enhances system reliability and security by promoting the entry of storage capacity to help to firm up the growing amount of renewable energy in the market • allows greater flexibility in how small storage units can be used in the market • aligns with the ESB's future direction of the trader-services model.
Recovery of non-energy costs	Two main changes: • The use of two new data streams in non-energy cost recovery — adjusted sent out energy (ASOE) and adjusted consumed energy (ACE). • Non-energy cost recovery would be based on a participant's gross energy flows.	The final decision removes the outdated participant category approach and provides a forward-looking framework that incentivises participants to manage their demand for these services by recovering non-energy costs proportionally from those who benefit from or cause the need for them.
Addressing inconsistencies in aggregation and ramp rates	Remove the 6 MW threshold for aggregating semi-scheduled units, creating one aggregation approach for semi-scheduled generating units and storage systems. Set a minimum ramp rate at the lower of 3 MW or 3% of capacity for scheduled units. An IRP may set separate up	This change sets minimum ramp rates to: • be more equitable for scheduled generation and load • be less complex for storage • allow semi-scheduled participants to aggregate units above 6 MW.

TOPIC	FINAL DECISION	RATIONALE
	and down ramp rates for the load and generation of its units.	
Network charges for storage	The final decision retains the current framework to allow storage to connect under a: • negotiated agreement at the transmission level • direct control service tariff or a storage tariff trial option, where offered, at the distribution level. Minor amendments have been made to the NER to clarify how the negotiated framework applies in relation to grid-scale storage and hybrids, and to accommodate the new IRP participant category. It also reduces barriers to the uptake of shared transmission services on a negotiated basis.	We consider that a change to the current framework that would automatically exempt storage from any network charges would not promote the NEO as it would not reflect the costs and benefits storage may have on the system. The Commission notes that the default position is not that storage must pay network charges. Rather, storage participants have the opportunity to choose the service they need and whether they go through the process of having a negotiated or prescribed shared transmission service. The Commission notes the rules were not designed for loads like storage that are price sensitive and can minimise impact on network congestion. It would be appropriate for a future rule change to address the broader issue of how network costs should be recovered.
Intervention compensation framework	The final rule does not develop any unique arrangements for storage and hybrids in the intervention compensation frameworks, but does integrate the IRP market participant category into these frameworks.	The benefits of the final rule are that it will: • consistently apply the intervention compensation framework across storage, hybrids, other generation and loads • build on changes made in a parallel rule change process on the intervention compensation framework.
Retailer Reliability Obligation (RRO)	The final rule makes IRPs liable entities under the RRO, in respect of their load, if aggregate annual load exceeds 10GWh in a particular NEM region.	The final rule will treat load of IRPs consistently with how load of Market Customers is treated. That is, any liable entity will be assessed to have a liable load where their

TOPIC	FINAL DECISION	RATIONALE
		aggregate load is greater than 10 GWh per annum.
Updating the language in the Rules	Using key terms such as load and generation in a more consistent way, replacing all mentions of offer with bid in Chapter 3 of the NER and providing generic references to scheduled plants and market participants where possible.	The benefits of the final rule are that it will: • improve the drafting of the rules by reducing the extent of technology specific, direction-specific and participant category-specific language • address the ambiguity of how certain terms and concepts apply to energy storage and hybrids • avoid implementing new definitions in the rules which are unnecessarily prescriptive on the direction of the flow of electricity • streamline the rules in a direction consistent with a potential future shift to a universal participant category.
Consolidating clauses in Chapter 2 that relate to ancillary services	This approach involves: • defining an umbrella term ('ancillary service unit') to replace the separate treatment of existing FCAS providers from load and generation • allowing the relevant types of Market Participants, including small resource aggregators, to provide FCAS under this umbrella term in accordance with the Market Ancillary Service Specification.	The final rule is more consistent with the ESB P2025 policy for a two-sided market. It creates frameworks that are more adaptable to change and better able to facilitate innovation, and reduce unnecessary differences in treatment between load and generation. The rule drafting is also streamlined as a result of this shift.
Streamlining the Rules	Improving the drafting throughout the Rules, where this is necessary or helpful, in clauses that are being amended for the changes above.	Given the final rule involves extensive drafting changes, this is an opportunity a 'spring-clean' and fix drafting errors or improve the clarity of provisions that are also being amended for the reasons above. These changes will contribute to the overall coherence of the Rules.

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APPENDICES

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1 AEMO'S RULE CHANGE REQUEST

1.1 The rule change request

On 23 August 2019, the Australian Energy Market Operator (AEMO) submitted a rule change request to the Australian Energy Market Commission (AEMC or the Commission) seeking to amend the National Electricity Rules (NER or Rules) to support the participation of energy storage systems as both standalone units and within hybrid facilities in the national electricity market (NEM). This included defining storage systems in the NER.

The Commission has completed three rounds of consultation on the rule change request. The consultation paper, options paper and draft determination stages are described below.

This chapter (**chapter 1**):

- outlines the rule change request
- explains its context and in particular, the relationship between the rule change request and the Energy Security Board's (ESBs) Post 2025 strategic policy direction
- gives an overview of the rule making process so far.

Chapter 2 sets out the Commission's final determination, including how the rule change request was assessed against the assessment framework and the reasons for the Commission's final determination.

The appendices provide more background information and a detailed overview of stakeholder feedback to the final determination and the Commission's analysis. The appendices are arranged as follows:

- Registration and participation framework (**Appendix A**)
- Recovery of non-energy costs (**Appendix B**)
- Network use of system charges (**Appendix C**)
- Other issues (**Appendix D**)
- The legal requirements under the National Electricity Law (NEL) for the final determination (**Appendix E**)
- Summary of the final rule (**Appendix F**).

1.2 Key terms used in the final determination

The following terms are used in this final determination:[2]

- **Storage:** encompasses different electricity storage technologies such as pumped hydro, batteries (grid-scale and exempt) or flywheels. It is an alternative term to Energy Storage Systems which AEMO uses in its rule change request. The Commission is no longer using Energy Storage Systems to refer to storage because the acronym is used by the ESB's post-2025 market design in its work on Essential System Services.

2 Additional defined terms can be found in the Abbreviations.

- **Grid scale batteries:** batteries that are 5 MW and above, the owners, operators or controllers of which are currently required under AEMO's policy to register in the NEM as a Market Generator (the battery being classified as a scheduled generating unit) and as a Market Customer (the battery being classified as a scheduled load).[3]
- **Exempt batteries:** batteries less than 5 MW, the owners, operators or controllers of which AEMO exempts from registering in the NEM.[4]
- **Hybrid facilities:** a grid-scale facility that has a group of assets that are co-located behind a single connection point that allow a registered participant to both consume and export significant amounts of electricity from or to the grid. This does not refer to aggregators of small customers with solar panels and batteries.

1.3 Current arrangements

When the NER were first drafted there was little storage in the system and the concept of single connection points with the potential for significant energy flows in both directions was not anticipated. As a result the NER do not define storage technologies or the ability to have bi-directional energy flows and there are no specific registration categories and classifications for storage units and hybrid facilities. This means that storage and hybrids must register in two separate categories.

In addition to being required to register and participate under two different categories, non-energy costs are currently recovered from storage differently compared to other market participants.[5] Grid-scale batteries are charged based on the two participant categories in which they are registered (market generator and market customer). This results in charges incurred for both consumed and sent out energy (based on gross meter data with two data streams). Other registered participants including market generators, market customers and Market Small Generator Aggregators (MSGAs) are charged based on being registered in a single participant category, where the consumed and sent out energy is netted within an interval (net meter data with one data stream).[6] [7]

Other relevant arrangements for grid scale batteries and hybrids are set out below:

- Batteries are currently liable as Market Customers under the Retailer Reliability Obligation (RRO) where their annual load exceeds the 10GWh threshold.
- Batteries are treated as both load and generation under the intervention compensation framework and so are compensated as two separate participants.
- They are currently subject to two different marginal loss factors (MLFs), one MLF on the load side and another for the generation side.

3 AEMO's policy is set out in its 2017 paper *Interim Arrangements for Utility Scale Battery Technology*, available on its website www.aemo.com.au.

4 AEMO, Integrating energy storage systems into the NEM — rule change request, August 2019, p. 9.

5 A full list of the NEM non-energy costs and the parties from whom these costs are currently recovered can be found in Appendix C.

6 This net meter data provides an energy value for market settlement, fees and non-energy cost recovery calculations. This arrangement has been in place since the commencement of the NEM and is reflected in the NER settlement formula as adjusted gross energy (AGE).

7 AEMO, *Integrating energy storage systems into the NEM - rule change request*, p. 15.

- Batteries are required by AEMO to be scheduled for their load and generation, if above the 5MW threshold.
- Batteries must bid in separately for load and generation; they cannot combine this into a single bid.
- For hybrids, the scheduling and dispatch obligations depend on the individual technologies and hybrids are required to issue separate bids for each different technology within the hybrid facility.
- The technical performance standards treat batteries as scheduled generation and load.
- Storage and hybrids are not explicitly represented on the Reliability Panel as they do not have a participation category that is represented on the Panel.
- Battery proponents are currently negotiating the application of network charges with network services providers (NSPs) at the distribution and transmission levels, on a case-by-case basis.

Smaller batteries that are less than 5MW are treated as generation and are currently included in the portfolios of MSGAs as though they were small generators. This treatment does not recognise that batteries also have a load side and can also offer these services in addition to generation.

1.4 Rationale for the rule change request

In the rule change request AEMO sought to provide greater clarity for how new technologies and business models, such as batteries and hybrid systems, register and participate in the NEM. AEMO considered this to be important in the context of:[8]

- growing grid scale battery storage connections[9]
- increasing numbers of applications and interest in registering storage systems and hybrid facilities[10]
- an expectation that there will be a growing role for storage into the future.[11]

While AEMO has made changes to its processes to accommodate batteries and hybrids, it says that issues remain because the NER create problems. In its rule change request, AEMO noted that categorising storage systems and hybrid facilities as both load and generation is having unintended consequences. The consequent impacts will be discussed in greater detail in subsequent chapters. However, in summary, AEMO is concerned that the current rules cause:[12]

- a lack of clarity in the NER for proponents regarding how to register and participate in the NEM

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8 AEMO, *Integrating energy storage systems into the NEM* — rule change request, p. 4.

9 See Appendix A for information about the numbers of grid scale batteries.

10 See Appendix A for information about upcoming storage and hybrid projects.

11 See Appendix A for information about AEMO's recent reports regarding the expected role of storage into the future, including the *2020 Renewable Integration Study* and the *2020 Integrated System Plan*.

12 AEMO, *Integrating Energy Storage Systems into the NEM* — rule change request, p. 17.

- increased operational complexity and inefficiency involved in treating a single asset as two components because the unit is treated as load and generation (in particular the need for storage to participate in dispatch with separate and simultaneous bids)
- possible issues where the technical requirements applicable at the grid connection point are not symmetrical for the same asset (for example ramp rates differ for the generation category compared to the load category)
- complicated IT arrangements for registered participants and AEMO
- difficulty for AEMO and other parties understanding and analysing market data, because it is necessary to reference two dispatchable unit identifiers (DUID) (one DUID for the generation category and one DUID for the load category) to understand the operation of the single storage asset
- uncertainty regarding the application of network charges at the transmission and distribution levels
- the recovery of non-energy costs not taking a technology neutral approach
- insufficient information provided on the limited energy capacity reserves of a storage system.

AEMO argued that the above combine to make the registration process slower, more expensive, complex and uncertain for batteries and hybrids, and increase AEMO's administrative costs and could impact on its role as market operator.[13] In addition, AEMO suggested that the existing NER contain barriers to entry for storage and hybrid facilities. Given the importance of storage and hybrids in supporting variable renewable energy (VRE), this is an issue that needs to be resolved to help facilitate the current transition in the NEM.[14]

AEMO also considered that the NER need to be changed to better recognise bi-directional flows. AEMO noted that the NER were written for an industry that was structured around one way energy flows from large generators to customers. However, the NEM is increasingly characterised by two-way energy flows where participants are both buying and selling electricity.[15]

1.5 Solution proposed in the rule change request

AEMO sought to resolve the issues discussed above by proposing a rule (proposed rule) to define storage and hybrid facilities, so that the NER can better recognise storage and connection points with bi-directional flows. To do this AEMO proposed that the NER should establish a new registration category called a "bi-directional resource provider" that could accommodate storage and hybrids with bi-directional flows and enable:

- storage and hybrids to register in one participation category instead of two
- batteries to be treated as a single scheduled asset and able to submit both load and generation tranches in the same bid

13 AEMO, *Integrating energy storage systems into the NEM* rule change request, pp. 17, 18.

14 AEMO, *Integrating Energy Storage Systems into the NEM* — Rule Change Request, p. 54.

15 AEMO, *Integrating energy storage systems into the NEM* — rule change request, pp. 4-5.

- storage to be treated equitably compared to other participants in the recovery of non-energy costs
- batteries to be exempt from being charged transmission use of system fees (TUOS) and for it be clarified that they will continue to be charged distribution use of system fees (DUOS)
- any necessary updates to be made to the performance standards for the connection of batteries and hybrids to the grid
- batteries to be exempt for being liable entities under the RRO
- the intervention compensation framework to specifically take into account batteries and hybrids
- the representation of storage and hybrid facilities on the Reliability Panel, if considered appropriate.

In addition, the proposed rule specified that with the definition of storage units in the NER, it would be possible to clarify that smaller batteries (less than 5 MW) can be included in the portfolios of MSGAs.

More broadly, the proposed rule also sought to update the language in the NER, which has become outdated as a range of market participants have significant bi-directional flows. AEMO noted that the NER were written in the context of generators that primarily sent out electricity and customers that primarily consumed electricity. Now, generation can be part of a battery or hybrid system that also draws from the grid and customers have installed growing amounts of behind the meter generation, and so they also export in increasing quantities.

AEMO's proposed solutions are discussed in greater detail in the relevant appendices of the draft determination, which can be accessed here.

1.6 Relevant background

1.6.1 Relationship with the Energy Security Board's Post 2025 market design

AEMO's proposed rule predates the work of the ESB post-2025 market design, which is considering a move away from defining specific technologies and assets in the rules towards a technology-neutral approach that attaches obligations to services and activities. One of the objectives of the ESB's work is to promote a two-sided market design, which includes better valuing the latent demand flexibility already existing within the system and increasing the quantity of flexible demand that is emerging with the growth in distributed energy resources (DER). When the demand side can better respond to price signals, it behaves in ways that benefit the system, reducing load when prices are high and increasing when prices are low. This reduces the need for investments in peaking generation and unnecessary network infrastructure upgrades.

There are many issues that need to be addressed on the path to a two-sided market. One of the key challenges is removing barriers to entry for more active participation on both sides of the market. The ESB's policy approach is to create a participation framework that supports the development of a two-sided market that focuses on addressing the costs and complexity of market entry. It also includes considering how to facilitate new business models and technologies, such as energy storage systems and those that involve aggregating customers' capability to provide demand response and other services, e.g. virtual power plants.

This is a similar objective to AEMO's proposed rule which seeks to remove barriers to entry for storage and business models that incorporate a mix of technology types, such as storage and different renewable generation, behind a connection point. Therefore, addressing the issues that AEMO has identified in its proposed rule can be considered as an important milestone on the path to a two-sided market.

The proposed design for a two-sided market promotes a trader-service model, which could:

- Simplify the existing registration process in the NEM by accommodating existing categories (other than network service providers) in a single 'trader' category. This would be one universal registration category covering all commercial parties participating in the NEM (e.g. retailers, aggregators, generators, scheduled loads, ancillary service providers). This would enable 'traders' to deliver a range of services to customers without having to register in multiple categories.
- Provide for greater regulatory flexibility that supports innovation by seeking to attach obligations to services at connection points as opposed to attaching them to registration categories and assets.
- Enable new participation models that allow customers to obtain services from more than one trader at a site. For example, a customer may have a contract with a trader providing standard retail services for the end user's uncontrolled load, and a separate arrangement with another trader that trades the end user's DER output or controlled load and buys and sells services on their behalf in the wholesale market.

The NER have been amended in recent years to add new categories of registered participant, resulting in one entity potentially needing to register in different categories in order to provide a range of services. This generally adds complexity and potential ambiguity for market participants and new entrants. There is also increasing overlap of formerly distinct categories (e.g. Market Customers representing 'load' connection points can be net exporters of energy at some intervals due to solar and other DER uptake). The trader-services model is an alternative to *ad hoc* changes to accommodate new business models and technologies. It is a framework that reflects the broader changes occurring in the NEM, where market participants are increasingly both consumers and generators of electricity. The intention is to make the arrangements in the rules keep pace and facilitate the changes in participation in the market, so they continue to be cost effective and meet the needs of market participants.

Additionally, the NEM arrangements, particularly for wholesale market participation, use 'asset focused' regulation. That is, participant categories (and the associated regulatory obligations) are based on the assets present, as opposed to the services bought or sold, at the connection point. This approach will become more complex as the number of services and service providers increase and new asset combinations emerge (e.g. hybrid facilities with load, generation and storage all behind a single connection point). The trader-services model allows innovations in services, without rigid market designs linking services back to physical types of generators, loads or storage devices. Technical capabilities and the set of services offered could then evolve without requiring incremental rule change processes.

The Commission has considered AEMO's proposed rule in the context of this broader reform. This has involved assessing additional solutions to AEMO's proposal to ensure that the NER are amended in line with the overarching policy direction. It is noted that implementing the trader-services model in full is a long-term reform that needs to be well sequenced and phased in over time. The final rule is a step towards the trader-services model that is within the scope of, and addresses, the issues AEMO raised in its rule change request.

1.7 The rule making process

1.7.1 The Consultation Paper

On 20 August 2020, the Commission published a notice advising of its commencement of the rule making process and consultation in respect of the rule change request.[16] A consultation paper identifying specific issues for consultation was also published. Submissions closed on 15 October 2020.

The Commission received 38 submissions as part of the first round of consultation.[17] Stakeholders had mixed views on the best solution to deal with the issues AEMO identified and a number raised the link between the proposed rule and the ESB's post-2025 market design initiative. AEMO also raised further issues relating to storage in its submission, on which other stakeholders had not yet had an opportunity to comment.

1.7.2 The Options Paper

In light of the feedback and the link with the ESB's work, the Commission granted an extension of time for this rule change to allow further engagement on alternative solutions that better align with the two-sided market design.[18] The Commission consulted further on several issues through an options paper. This paper was released on 17 December 2020 and submissions closed eight weeks later on 11 February 2021.[19]

Through the options paper, the Commission consulted further on the issues below:

- *Registration and participation*: The Commission sought feedback on four options for how storage and hybrid facilities could register and participate in the NEM. These covered a spectrum of options ranging from no change to more significant changes that attempt to move the market towards the trader-services model proposed in the two-sided market project.
- *Scheduling, dispatch, and performance standards*: The Commission sought feedback on how generation and load from storage and hybrid facilities should be scheduled and

16 This notice was published under s.95 of the NEL.

17 You can find the consultation paper and submissions to it on the project page here, under Initiation.

18 The date to publish the draft determination was extended to 29 April 2021. You can find the Notice of extension on the project page here.

19 The options paper and submissions on the options paper are on the project page here.

dispatched, and where performance standards should be set for hybrid facilities, i.e. at the connection point or the asset level.

- *Non-energy cost recovery*: The Commission asked how non-energy costs should be recovered from all market participants, including storage and hybrid facilities.
- *Additional storage-related issues raised by AEMO in its submission to the consultation paper:*
    - connection issues arising where the owner of a storage system is also the local network service provider
    - suggestions for simplifying the ancillary services provisions in the NER
    - opportunities to clarify how DC-coupled systems should register and participate in the NEM.

The Commission held a briefing for the options paper on 4 February 2021.[20] The Commission received 31 submissions in response to the options paper.

The Commission considered feedback provided by stakeholders in submissions. Issues raised in submissions are discussed and responded to throughout the draft rule determination, which can be accessed here.

1.7.3 Further consideration of implementation

On 29 April 2021, the Commission extended the time to publish the draft determination as AEMO requested more time to consider potential impacts from issues which it had previously not incorporated into its considerations, particularly on its operating systems and procedures.[21] AEMO had subsequently provided input on the cost breakdown of the key design features and this information has been included in Chapter 2.

1.7.4 The draft determination

On 15 July 2020, the Commission published the draft determination and draft rule. Submissions closed on 16 September 2020.

The Commission received 46 submissions as part of this third round of consultation.[22] Stakeholders were generally supportive of most of the draft decisions but many did not support the draft decision to not exempt storage participants from TUOS. Some of these stakeholders also raised alternative options for the Commission to consider.

1.7.5 Further consideration of stakeholder feedback to the draft determination

On 28 October 2021, the Commission extended the time to publish this final determination and final rule to consider the issues raised by stakeholders in their submissions.

20 The briefing session slides on the options paper are on the project page here.

21 AEMO's letter requesting the extension of time is on the project page here.

22 You can find the draft determination, draft rule and submissions to it on the project page here, under draft determination.

2 FINAL RULE DETERMINATION

This chapter provides:

- a summary of the Commission's final determination
- the relevant rule making requirements under the NEL, including the national electricity objective (NEO) and the more preferable rule test
- the Commission's assessment framework for considering the rule change request
- the Commission's consideration of the more preferable final rule against the NEO.

Further information on the legal requirements for making this final rule determination is set out in Appendix E.

2.1 The Commission's final rule determination

The Commission's final rule determination is to make a more preferable final rule, which is attached to and published with this final determination. The more preferable final rule includes the creation of a new technology neutral participant category called the integrated resource provider (IRP). This accommodates a variety of participants with bi-directional flows that provide and consume energy and may also offer ancillary services. It includes new grid scale storage, hybrids and aggregators of small generators and storage units. The final rule amends provisions throughout the NER to reflect this new participant category. In particular, the changes to registration and classification:

- enable storage and hybrids to register and participate in a single registration category rather than under two different categories
- provide clarity for scheduling obligations that apply to different configurations of hybrid systems
- introduce greater flexibility for storage, including allowing DC-coupled systems (which have different technologies behind a single inverter) who will be able to choose whether their coupled system is scheduled and/or semi-scheduled
- provide the ability for hybrid systems to store or consume energy when some constraints apply through aggregated dispatch conformance, subject to system security limitations
- enable storage to participate in dispatch as a single unit, facilitated by the proposed new term in the Rules — the bidirectional unit
- transferring existing small generation aggregators to the new category and allow these aggregators to provide market ancillary services from generation and load (aggregators of small generating units and/or storage units could continue to register as Market Customer).

The final rule also makes changes to a number of others areas in the rules. It:

- Amends the non-energy costs recovery framework so that recovery is based on a participant's gross consumed energy and/or gross sent out energy in an interval across its connection points. This is irrespective of the participant category in which it is registered.

The final rule removes the ability for a participant to net energy flows at a connection point or among its connection points.

- Retains the current framework to allow storage to choose between connecting under a negotiated agreement which may incur some network charges or the prescribed service and TUOS charge. The Commission notes that the default position is not that storage must pay network charges, including TUOS. Rather, storage participants may choose the service they need via the process of obtaining a negotiated or prescribed shared transmission service. In maintaining the current framework, the Commission's final rule does make minor amendments to the NER to clarify how the negotiated framework applies in relation to grid-scale storage and hybrids, and to accommodate the new IRP participant category. In particular, the final rule sets out the following transitional rule to reduce the risk of this final rule impacting on existing participants' connection agreements and agreed charges, see clause 11.145.14(a).
- Defines a new umbrella term for the provision of ancillary services to replace the separate clauses which relate to ancillary service generating units and ancillary service loads. The required changes to the definition of load have been made to achieve this. Additional changes have also been made to properly integrate the IRP in these provisions, including small resource aggregators (currently MSGAs).
- Updates technical performance standards with new terminology, including IRP and bidirectional unit, and provides clarity on how performance standards will apply to stand alone storage and hybrid facilities without any significant policy changes to the way in which standards are currently established and applied under chapter 5 of the NER.
- Change all mentions of 'offer' to 'bid' in Chapter 3 of the NER and to make generic references to scheduled plants and registered market participants throughout the rules where possible. It makes a more preferable rule to address the ambiguity of the terms 'load' and 'generation' as they apply throughout the NER.

A detailed description of the final rule is set out in Appendix F, and a summary of the changes between the draft and final rule is set out in Appendix G. Key differences between the proposed rule and the more preferable final rule are noted in the appendices.

The Commission's reasons for making this final determination are set out in section 2.4 below, as well as being discussed in more detail in the appendices and where relevant it has referred to the draft determination.

2.2 Rule making requirements under the NEL

2.2.1 Achieving the NEO

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the NEO.[23] This is the decision-making framework that the Commission must apply.

The NEO is:[24]

23 Section 88 of the NEL.

24 Section 7 of the NEL.

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.

2.2.2 Making a more preferable rule

Under s.91A of the NEL, 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 will or is likely to better contribute to the achievement of the NEO.

In this instance, the Commission has made a more preferable final rule. The reasons are summarised below. More detailed reasons for making this more preferable final rule, including analysis of the issues raised and responses to them, are set out in the appendices.

2.2.3 Rule making 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.[25]

For this rule change request, the Commission has determined that the reference to the "national electricity system" in the NEO includes the local electricity systems in the Northern Territory as well as the national electricity system.

This final rule relates to parts of the NER that apply in the Northern Territory. In making the final rule, the Commission has considered whether a uniform or differential rule should apply to the Northern Territory. The final rule determination is to make a uniform rule because the different physical characteristics of the Northern Territory's network would not affect the operation of the final rule in such a way that a differential rule would better achieve the NEO in this instance.

See Appendix E for further information on these determinations.

2.3 Assessment framework

In assessing whether the final rule is likely to contribute to the achievement of the NEO, the Commission has considered the following assessment criteria, in light of the current and future interests of consumers in a transitioning electricity system:

- ***Promotes competition:*** Will the rule remove barriers to entry and reduce operating costs?
- ***Promotes transparency:*** Will the clarifications to the obligations and charges in the rules reduce information asymmetry and improve the decision-making of participants?

25 *National Electricity (Northern Territory) (National Uniform Legislation) Act 2015* (NT Act). The regulations under the NT Act are the *National Electricity (Northern Territory) (National Uniform Legislation) (Modification) Regulations 2016*.

- ***Creates a level playing field:*** Are the obligations in the rule proportional, technology-neutral and do they provide participants efficient incentives across categories?
- ***Appropriately allocates risks:*** Will the appropriate parties be assigned responsibility for costs under the approaches in the final rule for cost recovery?
- ***Minimises administrative and regulatory burden:*** Will the changes reduce the administrative burden on AEMO and participants?
- ***Enhances system reliability and security:*** Will the obligations on storage improve reliability and security?

Promoting competition, including through enhanced transparency and enabling a level playing field, is in the long-term interests of consumers. This is because it increases choice for consumers, improves the service they receive and puts downward pressure on prices. In addition, ensuring appropriate allocation of risks and minimising administrative and regulatory burden contribute towards the efficiency of the market and in turn benefits consumers through fewer inefficient costs being passed onto them.

More broadly, the Commission considered how the rule change would benefit the reliability and security of the system (albeit indirectly) in light of the potential for new technologies and business models to assist in balancing the power system as the NEM continues its transition.

The assessment framework is consistent with that set out in the consultation paper and draft determination for this rule change process.

2.4 Summary of reasons

These changes will open the market up to greater participation by both small and large batteries. Greater participation from storage is essential to firm up the expanding volume of renewable energy as well as deliver the growing need for critical system security services as the ageing fleet of thermal generators retire. This will also likely lead to lower costs being passed onto end consumers through supporting cheaper renewable generation and increased competition to supply energy and ancillary services.

Having regard to the issues raised in the rule change request and during consultation, the Commission is satisfied that the more preferable final rule will, or is likely to, better contribute to the achievement of the NEO than the rule proposed by AEMO. The final rule:

Promotes competition:

- By removing barriers to entry for proponents of storage, hybrid facilities, and aggregators of small generating units and batteries. The more preferable rule promotes competition and removes barriers more effectively than AEMO's proposal because it:
  - accommodates aggregators as well as storage and hybrids in the proposed new participant category
  - gives hybrids more flexibility to manage electricity flows behind the connection point
  - accommodates DC coupled hybrids through clarifying the choices these configurations have regarding scheduling, allowing lower-cost system configurations to enter the market

    - enables aggregators of small units to provide ancillary services from those units.
- By providing a signal to the industry that the NER are being streamlined for the purpose of accommodating new technologies, business models and services that offer greater choice for consumers. The more preferable rule provides a stronger more enduring signal because it is technology-neutral and is consistent with the ESB's long term goal of a two-sided market for energy services.

Promotes transparency:

- By clarifying the obligations that apply to storage and hybrids, including:
    - that batteries can participate in dispatch through a single bid (making it easier to interpret market data)
    - how performance standards will be set for hybrids that have a mix of synchronous and non-synchronous technologies
    - how the minimum ramp rates apply.
- By updating the language and streamlining the NER so that it more appropriately accommodates new technologies and participants with significant bi-directional flows and makes the NER easier to read and understand.

Creates a level playing field:

- By introducing a new participant category. The more preferable rule more effectively contributes to a level playing field by avoiding the inclusion of additional technology-specific terms in the NER, such as a definition for storage. It takes a substantial step towards the trader-services model (part of the ESB's proposed P2025 reforms) that aims to achieve a technology-neutral services-based approach to applying obligations.
- By confirming the existing negotiated transmission framework which has been used by storage participants to date is to continue to apply to future storage and hybrids. This final decision to not change the existing framework and provide clear guidance on the intent of this rule provides some clarity for new storage and hybrids connecting to the NEM in the near term. However, the Commission considers, that there are broader issues with network charging for storage and other participants, and this should be addressed in a separate rule change.
- By amending the non-energy cost framework to ensure a consistent and efficient approach across participant categories and technology types in light of increasing bi-directional flows. The more preferable rule provides efficient incentives through applying a consistent approach to all participant categories, rather than only providing efficient incentives between grid-sized and smaller (exempt) batteries that are operated by MSGAs.
- By confirming that existing mechanisms in the NER, including the intervention and compensation framework and the RRO, will apply to storage and hybrids in the same way that they apply to other generators and loads.

Appropriately allocates risks:

- By amending the non-energy cost recovery framework so that participants have costs recovered from them when they contribute to a security or reliability event. The non-energy cost changes strengthen the causer pays signals to participants to encourage them to behave in ways that help promote the reliability and security of the system.

Minimises administrative and regulatory burden:

- By clarifying the registration and classification process for storage and hybrid facilities.
- By consolidating and streamlining the registration and classification provisions for market participants.
- By making it easier for AEMO's systems to receive bids from batteries and interpret market data (by enabling hybrids and energy storage systems to be a single unit, in certain circumstances).
- By clarifying the meaning of key terms such as "load", and ensuring these terms are used consistently throughout the NER and are not used in such a way as to be unnecessarily restrictive given the prevalence of two-way electricity flows.

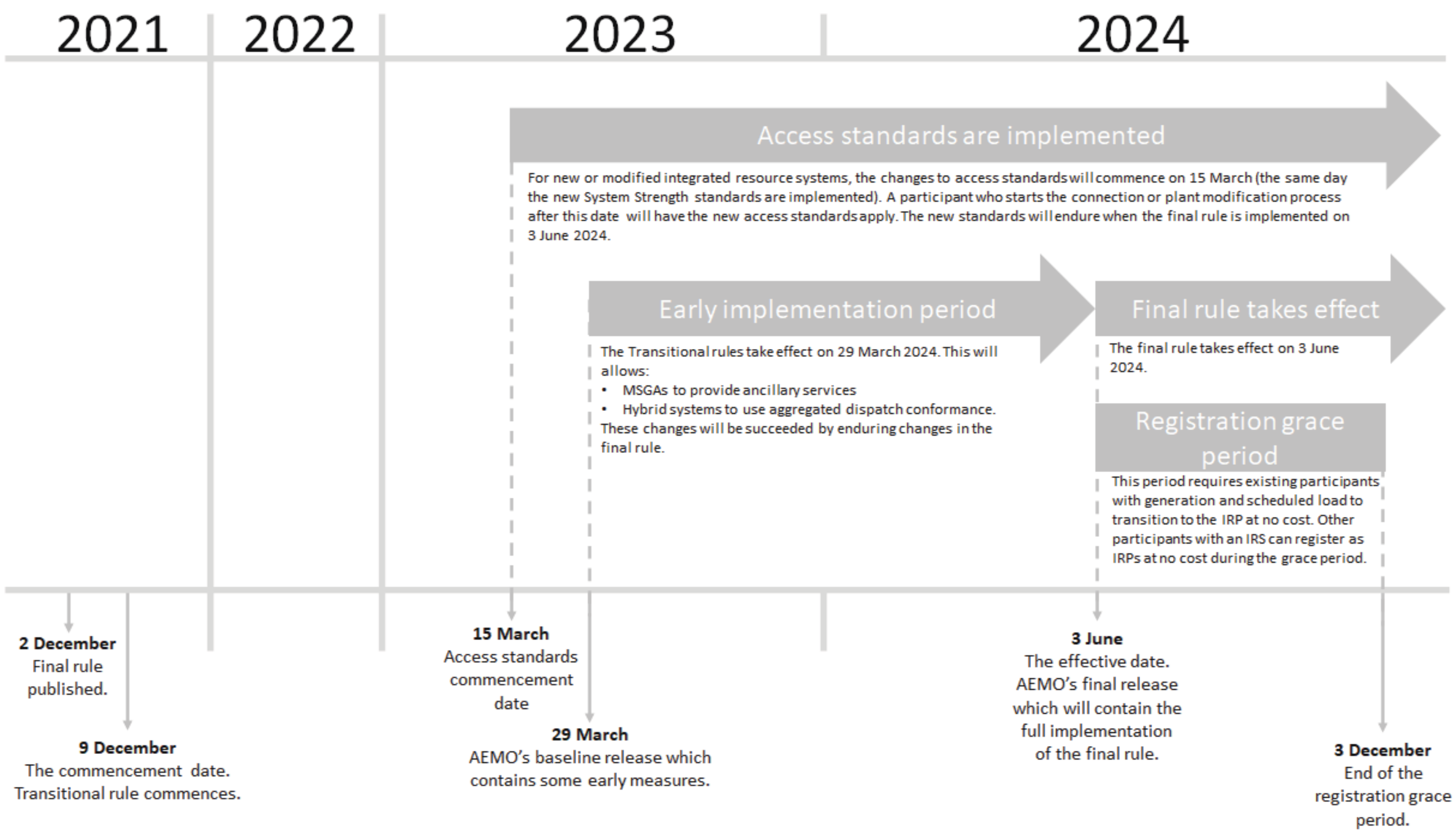
Enhances system reliability and security:

- By facilitating storage to participate in the NEM and thereby helping to increase the proportion of fast-responding dispatchable resources, which are needed to support increasing amounts of renewable generation.

2.5 Implementation of the final rule

The majority of the final rule will take effect on 3 June 2024, due to the time required by AEMO for implementation activities. However, some key benefits have been brought forward and will be available from the end of March 2023. Figure 2.1 sets out the implementation of the rule.

Figure 2.1: Implementation of the final rule



ABBREVIATIONS

AC	Alternating current
ACE	Adjusted consumed energy
AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGE	Adjusted gross energy
ASOE	Adjusted sent out energy
DC	Direct current
DER	Distributed Energy Resources
DNSP	Distribution network service provider
DUID	Dispatchable Unit Identifier
DUOS	Distribution use of system
ESB	Energy Security Board
FCAS	Frequency Control Ancillary Services
IRP	Integrated Resource Provider
IRU	Integrated Resource Unit
ISP	Integrated System Plan
MASS	Market Ancillary Service Specifications
MLF	Marginal loss factor
MSATS	Market Settlement and Transfer Solution
MSGA	Market Small Generation Aggregator
MW	Megawatt
MWh	Megawatt-hour
NEL	National Electricity Law
NEM	National electricity market
NEMDE	NEM Dispatch Engine
NEO	National electricity objective
NER	National electricity rules
NSP	Network service provider
PASA	Projected assessment of system adequacy
REZ	Renewable Energy Zone
RRO	Retailer Reliability Obligation
SAPS	Stand-alone Power Systems
SGA	Small Generator Aggregator
TNSP	Transmission network service provider
TUOS	Transmission use of system
VRE	Variable renewable energy

A REGISTRATION AND PARTICIPATION

BOX 1: FINAL RULE — REGISTRATION, CLASSIFICATION AND PARTICIPATION FRAMEWORK

The key features of the final rule are:

- the introduction of a new IRP participant category for storage and hybrid system operators
- the introduction of a new classification category, the bidirectional unit, which will be utilised by IRPs to classify storage (this is a change in name from the draft decision — we have replaced the proposed term 'integrated resource unit' with 'bidirectional unit' in response to stakeholder feedback)
- scheduling and dispatch obligations are set at the unit level, with conformance with dispatch for hybrids measured in aggregate where possible and appropriate
- inclusion of small unit aggregators in the IRP category, with the ability to provide ancillary services.

A more detailed summary of the final rule can be found in Appendix F.

Definition of storage in the NER

The Commission's final decision is for a technology-neutral approach for any new definitions in the NER to accommodate storage and hybrid facilities. This involves establishing a new term, bidirectional unit, for a unit that has both load and generation that does not refer to energy storage specifically. Energy storage is not defined as a service separate from generation and load. Instead of defining a new service, a bidirectional unit generates and consumes electricity.

Registration and classification

The Commission's final decision is to create a new participant category, the IRP, for storage and hybrid proponents, including aggregators of small units. It would be optional for any existing Generator or Customer to, with the consent of AEMO, change its registration category to IRP. From the effective date, it would be mandatory for any new participant to register as an IRP if, behind a single connection point, it has both:

- generation capability, that on its own would see it register as a Market Generator
- consumption from the connection point above auxiliary load (which is now defined to exclude load used to charge a battery or pump water in hydro facilities).

It is also mandatory for an existing participant that has scheduled load as well as generation in the same facility to transition to the IRP category. This will be a relatively quick and straightforward process. AEMO will not charge fees for this re-registration and reclassification, and will not re-examine an existing unit's compliance with its performance standards.

Participants registered as Small Generation Aggregators will be automatically transferred to the IRP category, and as such would be Small Resource Aggregators in respect of each of their small generating units.

An IRP:

- must classify standalone storage, 5 MW and above, as a scheduled bidirectional unit
- may classify storage under 5 MW as a non-scheduled bidirectional unit
- must classify each generating unit or bidirectional unit separately within a hybrid system, where scheduling requirements apply
- may classify connection points that do not have grid-scale generation or storage facilities as its market connection points, if it chooses to do so
- may classify loads as scheduled loads, if it chooses to do so
- may classify ancillary service units
- must classify a system that doesn't transition linearly through zero as a scheduled generating unit and scheduled load.

Aggregators of small storage units below 5 MW and small generating units below 30 MW will be allowed to register in the IRP category, under the new label Small Resource Aggregator. As well as selling unscheduled generation from these units in the spot market, this would allow them to provide market ancillary services from generation and load, where they meet the technical requirements to do so. This change includes moving the existing MSGA category into the IRP.

Participation

Under the final rule a bidirectional unit will have 20 price bands.

A storage unit that is unable to participate as a single unit (for example, certain types of hydro facilities that have a dead band when transitioning between generation and consumption) would continue to participate as a scheduled load and a scheduled generating unit, separately.

Aggregators of small units will not be required to participate in central dispatch.

Hybrid facility proponents will be required to register as an IRP and each unit within the facility will participate in central dispatch to the extent required by its classification. AEMO will be required to develop a new approach to assessing dispatch conformance for hybrid facilities in aggregate, where that does not risk the stable operation of the system.

For operational and technical issues raised by AEMO, the Commission made the these final decisions:

- **Ramp rates and aggregation** — Create one aggregation approach for semi-scheduled generating units and storage systems, reflecting NER clause 3.8.3. Set a minimum ramp rate at the lower of 3 MW or 3 per cent of capacity for scheduled units and remove the 6

MW threshold for aggregating semi-scheduled units. An IRP may set separate up and down ramp rates for the load and generation of its units.

- **Bidding parameters and forecasting** — Made minor changes to integrate the IRP effectively. Three provisions included in the draft rule, that would have required storage units to provide interval-level energy availability forecasts, have been removed in the final rule. Broader issues with forecasting and unit availability, for all participants not just those with storage, have not been further considered in this final rule.

Benefits of the final rule

The benefits of the final rule include:

- lower barriers to entry for new storage participants as a result of:
  - creating a clear regulatory framework for storage and hybrid participants to register, classify and participate in the NEM
  - reducing the administrative burden to register and classify storage units and hybrid facilities
- reducing system costs for AEMO by setting clear registration pathways and more efficient operational integration of storage and hybrids
- increasing operational efficiency through providing flexibility for hybrid facilities to manage energy flows between units behind the connection point
- improving competition in the ancillary services market by allowing Small Resource Aggregators to provide these services which will likely reduce system costs of procuring them.

A.1 Overview

The Commission's final decision largely retains the draft decision to introduce the new IRP participant category and a technology-neutral approach for any new definitions in the NER to accommodate storage and hybrid facilities. All existing and new grid-scale storage and hybrid systems will be required to register in this category. Aggregators of small units, and entities that would otherwise register as Generators or Market Customers, will also be allowed to register under the IRP category and provide energy and ancillary services into the market.

The final decision lowers barriers to entry for new storage participants, small and large, by creating a clear and simple regulatory framework for participation in the NEM. It increases operational efficiency by providing flexibility for hybrid facilities to manage energy flows between units behind the connection point. This decision aligns with the ESB's longer term view of a trader-services model for participation in the NEM with a universal participant category. Establishing the IRP is a no-regrets first step toward that longer-term outcome.

This appendix discusses the following about registration, classification and participation:

- stakeholder feedback to the draft determination

- the Commission's analysis and final decision
- background information.

A.2 Stakeholder views on the draft determination

A.2.1 Registration and classification

Registration and classification

A majority of stakeholders supported the introduction of the IRP registration category and IRU classification for storage and hybrid system participants, and noted these options would:

- simplify the NER by removing barriers and streamlining the registration and classification process for storage and hybrids[26]
- provide greater investment certainty[27]
- allow for a broad range of emerging business models, including AC and DC-coupled hybrid units and batteries used for behind the meter smoothing[28]
- provide a clear framework for hybrids[29]
- align with the trader-services model under the ESB's two-sided market reform proposals[30]
- complement other major reforms, including the *Access, pricing and incentive arrangements for distributed energy resources* and *Wholesale demand response mechanism* rule changes[31]

Iberdrola supported the draft decision to not impose a fee on those participants who would need to transition to the IRP. Endeavor Energy supported maintaining existing Generator and Customer obligations on IRPs.[32]

Other stakeholders considered that existing storage participants should not be forced to re-register as IRPs and therefore should be grandfathered across in the Rules because it:

- was unclear what benefits the IRP offered them[33]
- would avoid unnecessary administrative burdens and re-registering risks[34]

A number of stakeholders noted it was not clear that the benefits outweighed the cost and considered that the Commission should:

- set out what the stand-alone benefits of introducing the category are over tweaking existing categories, even in the absence of two-sided market reforms as it is too early to conclude this will be the outcome[35]

26 Submissions to the draft determination: Flow Power, p.2; Simply Energy, p. 1; CEC, pp. 1-2.

27 Submissions to the draft determination: AusNet Service, p.1; CEC, pp. 1-2.

28 Iberdrola, submission to the draft determination, p. 6.

29 Submissions to the draft determination: SA Dept. Energy and Mining, p. 2; Meridian Energy, p. 2; CEC, pp. 1-2; Enel Green Power, p. 1.

30 Submissions to the draft determination: SA Dept. Energy and Mining, p. 2; Simply Energy, p. 1; Endeavour Energy p. 1.

31 AusNet Services, submission to the draft determination, p. 1.

32 Submissions to the draft determination: Iberdrola, p. 6; Endeavour Energy, p. 1.

33 Submissions to the draft determination: CleanCo, p. 6; AGL, p. 2; Origin Energy, pp. 1-2.

34 Submissions to the draft determination: AEC, p. 3; Origin Energy, pp. 1-2

35 Submissions to the draft determination: Origin Energy pp. 1-2; Alinta Energy, p. 1.

- clarify how the benefits outweigh the cost to implement.[36]

Neoen did not support introducing the IRP, stating it provided no benefit to its operations, reduced functionality and created implementation costs.[37]

In submissions and discussion forums, many stakeholders sought clarity and certainty on the re-registration process and how this would impact on existing generator performance standards.[38]

Stakeholders also sought clarity on:

- whether it was necessary to include non-registered IRPs, as non-registered IRPs cannot operate without changes to retail rules to allow a party other than a retailer to sell electricity to a customer[39]
- if the rule will continue to provide flexibility for existing SGAs (that will become IRPs) to offer services to customers using the embedded network configuration, or any future configuration that may be developed as part of the ESB's consideration of flexible trader models[40]
- the need to clearly separate out the treatment of facilities that are designed to provide services to the wider system and consumers and those that are intended for use behind the connection point.[41]

Both AEMO and Sun Metals considered the term Integrated Resource Unit (IRU) could create confusion for participants when compared with other similar terms like IRP and integrated resource system. AEMO noted that while it may not be a material issue at this time, clarity would become increasingly important as participants look to utilise and expand the nature of their asset installations. AEMO suggested a different term, bidirectional resource unit, could be used instead.[42]

AEMO also noted that introducing the new IRP category will drive changes to its process and systems as it will break the existing links between a registration category and the participant's role in the market, access to systems and the processes that AEMO manages such as prudential requirements and settlements.[43]

DC-coupled systems

All stakeholders who commented on the flexibility and options created for DC-coupled systems were supportive[44], noting the draft decision would:

36 Shell, submission to the draft determination, p. 2.
37 Neoen, submission to the draft determination, pp. 3-4.
38 Submissions to the draft determination: Engevity, p. 3; Origin Energy, p. 4; Shell, p. 10.
39 AusNet Services, p. 3.
40 Enel X, submission to the draft determination, p. 2.
41 Sun Metals, submission to the draft determination, p. 4.
42 Submissions to the draft determination: AEMO, p. 6; Sun Metals, p. 4.
43 AEMO, submission to the draft determination, p. 8.
44 Submissions to the draft determination: Engevity, p. 2; Terrain solar, p. 3; EnergyAustralia, p. 2; Fluence, p. 4; Firm Power, p. 4; CEC, p. 2.

- provide participants with flexibility to pursue innovative business models[45]
- incentivise greater uptake and provide numerous cost saving opportunities by sharing resources and assets between the coupled units.[46]

Both Terrain Solar and Firm Power considered that no specific changes are required to performance standards for DC-coupled systems compared to other forms of hybrid facilities. Both encouraged AEMO to release further guidance on the assessment of DC-coupled system performance standards and the telemetry and metering requirements shortly after the final rule is published.[47]

While supportive of the changes, Shell considered there is the potential for unintended consequences for the semi-scheduled DC-coupled option where the battery may be able to operate unconstrained. Shell suggested changes to remove this risk:

- require every dispatch instruction issued to be a semi-dispatch interval
- require the registered capacity of the facility to be capped at the size of the intermittent generator(s)
- allow the facility to consume from the grid as a semi-scheduled load.[48]

AEMO was supportive of a framework that allows DC-coupled systems. However, it noted that to maintain a consistent approach with AC-coupled battery systems it intends to fully schedule any DC-coupled battery systems with a capacity of 5MW or greater.[49]

Generator performance standards

Most stakeholders who commented on generator performance standards were more concerned with ensuring that there would be no reopening of performance standards for storage participants re-registering as IRPs, or existing generators who wanted to added storage.[50]

EnergyAustralia and Origin Energy supported the draft decision to maintain the existing arrangement of generally measuring performance at the connection point, but allowing flexibility in how this is applied to cater for different assets and configuration.[51]

Sun Metals raised concerns about how the new term, integrated resource system, was integrated into various parts of rules. It considered that it is unreasonable to extend the generator performance standards to scheduled and non-scheduled loads that are part of a hybrid system e.g. unreasonable to expect load to provide voltage control, or maintain active power, or continuous uninterrupted operation.[52]

45 Engevity, submission to the draft determination, p. 2.
46 EnergyAustralia, submission to the draft determination, p. 2.
47 Submissions to the draft determination: Terrain solar, p. 3; Firm Power, p. 4.
48 Shell, submission to draft determination, pp. 8-9.
49 AEMO, submission to draft determination, pp. 17-18.
50 Submissions to the draft determination: Origin Energy, p.4; Engevity, p. 3; Shell, p. 10, Iberdrola, p. 6. CEC, p. 2.
51 Submissions to the draft determination: EnergyAustralia, p. 2; Origin Energy, p. 4.
52 Sun Metals, submission to the draft determination, p. 4.

Firm Power considered the final rule should clarify the approach to assessing performance standards for hybrid and IRP projects, particularly DC-coupled systems or otherwise clarify that the existing performance standards will apply to hybrid systems.[53] While Shell considered it was unclear how practical and achievable it would be to assess performance standards at the connection point when they could apply to a number of different technologies within the hybrid system.[54]

A.2.2 Participation

Central dispatch

Number of dispatchable unit identifiers and bid bands

Only a few stakeholders commented on the number of DUIDs. Flow Power, Fluence and AGL questioned if the benefits outweighed the costs, while Shell considered that if a single DUID was maintained for the final rule, participants should be given the choice of a single DUID or two DUIDs.[55]

All stakeholders who commented on the number of bid bands agreed with 20 bid bands if the decision was made to move to a single DUID.[56]

AEMO supported the move to a single DUID and noted it expects it could implement this approach largely by applying existing functionality. This would minimise the complexity and cost. Further, while its current thinking is an IRP would bid and be dispatched under a single 'parent' DUID for its bidirectional units, NEM Dispatch Engine (NEMDE) itself could continue to optimise separate (but linked) child DUID bids for the load and generation components of the battery.[57]

Dispatch aggregate conformance

Those stakeholders who commented were generally supportive of allowing hybrids systems to meet dispatch conformance in aggregate.[58] However, some considered that greater clarity is needed on how it would apply:

- Sun Metals wanted the scope broadened to include unscheduled resources, so that a hybrid could use a single scheduled resource to supply its load at any level, except where dispatch compliance is required.[59]
- Fluence and Iberdrola considered that the framework needed to be clear on when and how it would be applied to give developers and investors confidence. For example, how

53 Firm Power, submission to the draft determination, p. 3.
54 Shell, submission to the draft determination, pp. 7-8.
55 Submissions to the draft determination: Flow Power, p. 2; Fluence, pp.4, 12; AGL, p. 1; Shell p. 10.
56 Submissions to the draft determination: Snowy Hydro, p. 3; Origin, p. 4; CEC, pp. 1-2.
57 AEMO, submission to the draft determination, p. 13.
58 Submissions to the draft determination: AEMO, pp. 16-17; SA Dept. Energy and Mining, p. 2; Sun Metals, pp. 8-9; Fluence, pp. 5-9; Iberdrola, pp. 6-7.
59 Sun Metals, submission to the draft determination, pp. 8-9.

would aggregate conformance work when thermal and system strength constraints applied?[60]

AEMO supported introducing dispatch aggregate conformance for hybrid systems, but noted the NEM is becoming less stable to operate and this provides a challenge for implementation. AEMO considered that:

- it needs the ability to carry out due diligence on hybrid facilities, including consideration of potential locational issues such as system strength or voltage disturbance
- it needs the ability to reject the use of an aggregated conformance approach for a hybrid generating system where these issues are acute
- the aggregated conformance should be made available for hybrid generating systems on application, and may be rejected by AEMO in specific circumstances.[61]

Alinta Energy suggested more generally that a registration framework that allows aggregation, should also allow facilities behind the connection to withdraw from these arrangements and register separately so that they are not unduly locked into uneconomic arrangements. That is, registration as an IRP should not be a 'one-way gate' for incumbents, nor new entrants.

Shell considered it was not clear the benefits outweighed the costs, noting implementation would be complex and costly, and it was unclear how it would work for Frequency Control Ancillary Services (FCAS) as it is measured at the unit terminal.[62] Neoen considered the IRP framework more broadly was complex and costly, and that greater flexibility would be a better approach, for example, an exemption framework that allowed participants to integrate batteries with larger renewable generator where they would be under a single control system, and therefore not disincentivised by having to scheduling the battery separately.[63]

Aggregators providing ancillary services

Those stakeholders who commented on the change to allow aggregators of small generating or storage units to provide ancillary service were supportive and noted it:

- removes regulatory barriers to small generation aggregators[64]
- will allow community batteries to participate in providing FCAS[65]
- is an important step forward in enabling battery and hybrid units to support system security through the provision of regulation FCAS services.[66]

Both Enel X, and Citipower, Powercor and United Energy considered this a priority change that should be brought forward in the implementation.[67]

60 Submissions to the draft determination: Fluence, pp. 5-9; Iberdrola, pp. 6-7.

61 AEMO, submission to the draft determination, pp. 16-17.

62 Shell, submission to the draft determination, p. 7.

63 Neoen, submission to the draft determination, p. 4.

64 Submissions to the draft determination: Flow Power, p. 2; Origin Energy, p.2; Yes Energy p. 1; Tesla, p. 14; Enel X, p. 3; AusNet Services, pp. 2-3; Citipower, Powercor, United Energy, pp. 1-2; Simply Energy, p. 1.

65 Submissions to the draft determination: SA Dept. Energy and Mining, p. 2; Citipower, Powercor, United Energy, pp. 1-2.

66 AusNet Services, submission to the draft determination, pp. 2-3.

67 Submissions to the draft determination: Enel X, p. 3; Citipower, Powercor, United Energy, pp. 1-2.

Some stakeholders sought clarity on how community batteries will be affected by this rule change and if retailers will be able to continue operating them under the existing retailer VPP framework before and after the final rule is implemented.[68]

Ramp rates and aggregating semi scheduled unit

Stanwell and Fluence supported the draft changes to address inconsistencies in ramp rates and thresholds for aggregating semi-scheduled units, to ensure consistency between storage and non-storage participants, load and generation units, and scheduled and semi-scheduled units.[69]

Bidding parameters and forecasting

Shell noted if the single DUID bid form for an IRU was not clear it would replicate the existing bidding arrangements, and recommended that the final determination allows an IRU to provide separate:

- maximum and projected assessment of system adequacy (PASA) availability values
- up and down ramp rates for dispatch as a generator (i.e. when providing active energy) and as a scheduled load (consuming active power).[70]

Shell and Neoen raised concerns on the new subclauses, 3.7.3(e)(5), 3.8.4(c)(3A) and 3.8.6(g2), in the draft rule that would require batteries to forecast future energy availability for each 228 trading intervals across the day. Their concerns were that batteries could not accurately forecast future availability as it would be directly dependent on what they are dispatched for in the preceding interval, and this would represent a compliance trap.[71]

A.3 The Commission's analysis and final decision

A.3.1 Registration and classification

The Commission's final decision is to create a new participant category, the IRP, and a new classification, the bidirectional unit. These changes will simplify the registration and classification process for storage and hybrid systems. The final decision retains the draft decision, with minor amendments to address issues raised by stakeholders.

The following sections provide the Commission's analysis including addressing stakeholder feedback to the draft determination. Further background and analysis supporting the Commissions final decision can be found in the draft determination here, see appendix B, section B.6.

Amendments to registration and classification provisions

The amendments from the draft to final decision are:

68 Submissions to the draft determination: Simply Energy, p. 1; Citipower, Powercor, United Energy, pp. 1-2.

69 Submissions to the draft determination: Stanwell, p. 1; Fluence, p. 4.

70 Shell, submission to the draft determination, p. 9.

71 Submissions to the draft determination: Shell, p. 9; Neoen, p.4.

- Simplification of the process for existing grid scale storage participants to transition to the IRP, including specifying that the participant will not have to satisfy AEMO that its existing facility will be capable of meeting its performance standards, and AEMO is not required to be satisfied that the participant will be able to fulfil the applicable financial obligations and has demonstrated an ability to comply with the rules.[72] The Commission considers these changes address the risk stakeholders identified with the re-registering process outlined in the draft determination. Additionally, the transitional rule states that this final rule, and any changes in registration or classification for existing participants, are not intended to re-open performance standards, service levels or other terms of transitioning participants' connection agreements.[73]
- Small resource aggregators will only be able to classify exempt generating units/bidirectional units where there is a separate connection point (ie no retail load).[74] This change supports the continuation of current aggregator business models (which do not involve retail authorisation).
- The proposed term for the new classification 'integrated resource unit' has been changed to 'bidirectional unit' for greater clarity in the rules. The new name highlights the key characteristic of such units (the two-way flow of energy). The difference between the new name for the unit and the participant category name (integrated resource provider) avoids the impression that IRPs can only classify these units; IRPs can classify a range of units.

Other key features of the new framework

The other key features of the final decision on registration and classification are:

- It will be mandatory for each existing and new participant with scheduled load as well as generation in one facility to become an IRP.
- Storage participants whose units have a dead band around their zero point of generation/consumption, typically hydro units, will be required to register as IRPs. These participants' facilities will, however, maintain dual classifications as a scheduled generating unit and scheduled load.
- Operators of hybrid systems will register as IRPs and will classify each unit or load behind the connection point separately, according to their technical capabilities.
- It will now be possible to couple separate generation and bidirectional units together on the DC side of the inverter (a DC-coupled system). There will be flexibility available in how these register and classify. This is explained in more detail further below.
- Operators of small generating and storage units, currently registered as MSGAs, will be moved to the IRP under the label "small resource aggregator". They will have no change to their scheduling or dispatch obligations for energy, but will now be able to provide ancillary services where they meet the MASS and classify the relevant plant as ancillary service units.

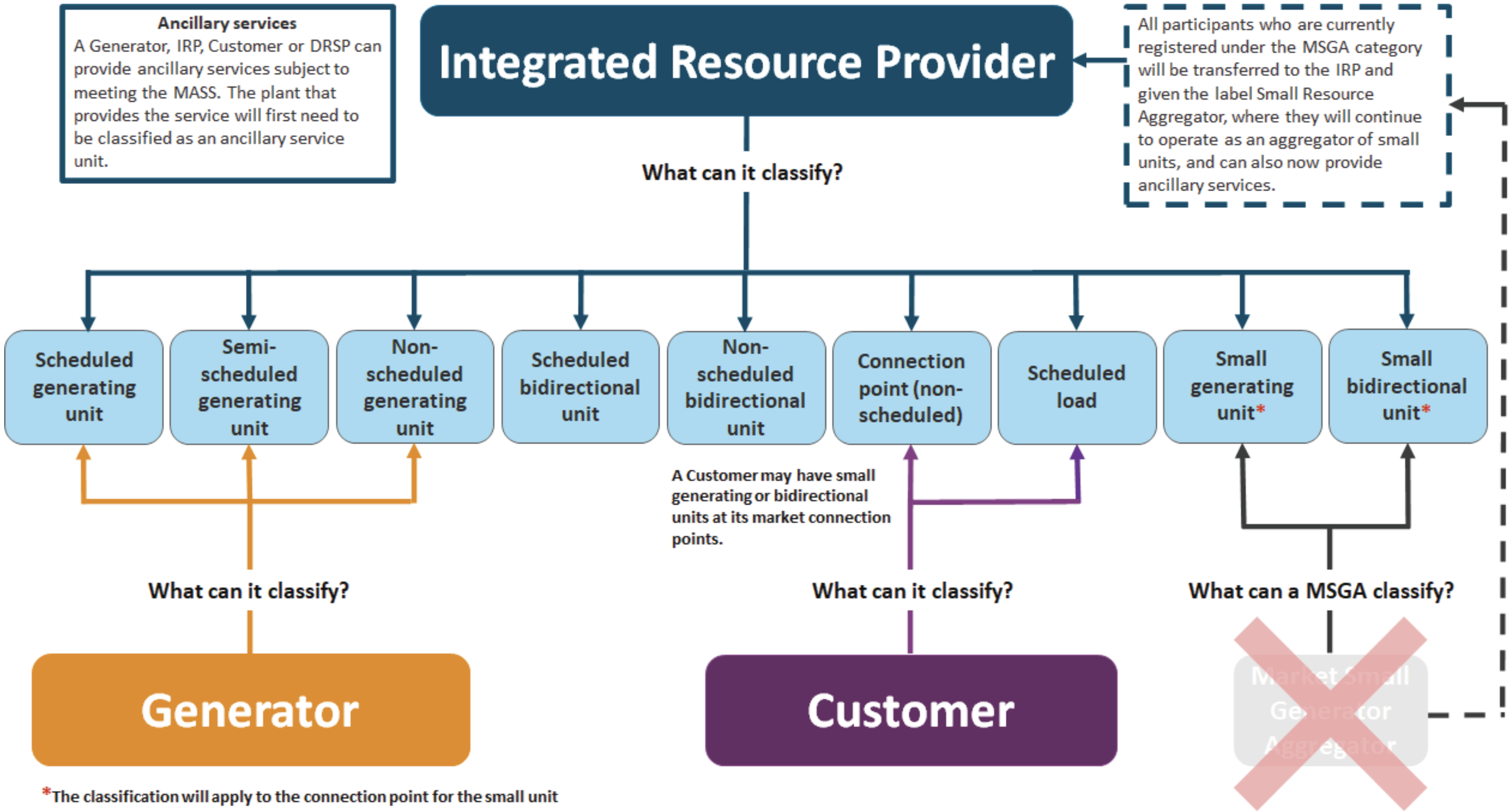
72 Final rule, new clause 11.145.2.

73 Final rule, new clauses 11.145.5 and 11.145.14.

74 Final rule, new definition of "small resource connection point" in chapter 10.

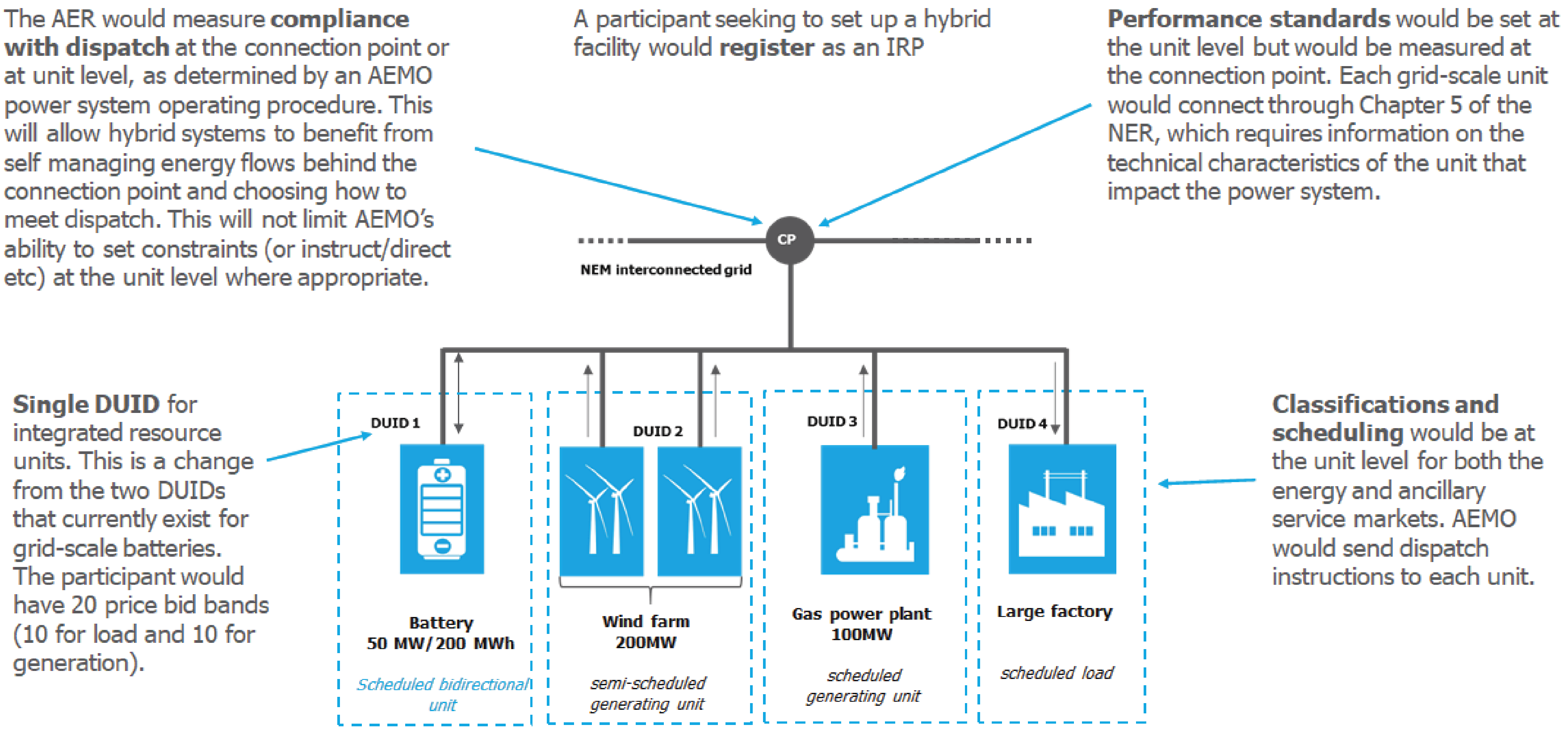
The IRP category can accommodate a variety of participants with bidirectional energy flows that may offer and consume energy and ancillary services. This includes grid-scale storage, hybrids and aggregators of small generation and storage units. Figure A.1 outlines the range of classifications and services that can be provided by the IRP. It is optional for Market Customers and Generators to join the IRP category. Figure A.2 outlines a number of key design features for hybrid facilities.

Figure A.1: Classifications and services that can be provided by Market Participants



Source: AEMC

Figure A.2: An example of a hybrid facility registered as an IRP



This diagram is an example of a potential hybrid facility. A hybrid facility could vary in the number and type of units behind its connection point.
Source: AEMC

The benefits of creating the IRP over amending existing categories

The Commission considers the IRP category provides a clear and simple framework for storage and hybrid systems to register and participate in the NEM, and that it is more preferable over the alternative approaches that were explored in the options paper.[75] The Commission provides the following analysis in response to stakeholders' request for clarity around the benefits of the final decision:

- Introducing a new single registration category for storage and hybrid systems creates a clear, simple and flexible framework that reduces the complexity of the existing framework. If the Commission only modified existing registration categories, some existing issues of complexity and lack of clarity would still persist. This is because there would be multiple registration combinations that would be possible, depending on what size and classifications of load and generation an intending participant is pursuing.
- The IRP adopts many of the same design features that would likely have been made under the option to modify existing registration categories. However, it implements these through a single category which is an easier framework for participants to navigate. The IRP does not implement a number of features explored in the options paper that were pitched at the 'greater change' end of the spectrum as these were a significant step change for industry and participants.[76]
- Importantly, the final decision includes clearer rules and allows greater participation from small storage units through allowing IRPs to classify small units and provide ancillary services from these and small generating units. This is a material change for aggregators of small generating and storage units and provides a strong market signal to investors that the new category is being set up to accommodate and promote innovation.
- The IRP has been designed to solve existing issues for storage and hybrid systems but also aligns with the longer term direction towards a two-sided market which would have a universal participant category based on services rather than assets. The Commission's view, as well as many stakeholders, is that an incremental approach that aligned with the ESB's direction is preferred. This is an approach that sees enduring changes made now that will not need to unwound in the near future.
- The final decision is still considered to best address the issues and concerns raised in the rule change request and by stakeholders, irrespective of a universal category being created in the future. This is because:
    - discussions with AEMO noted it is not clear that modifying existing registration categories would be a materially cheaper solution as many of the changes being made under the final rule would still need to be made, including changes to AEMO's processes and procedures

75 Further detail on the registration and participation options the Commission explored during the rule change process can be found in the options paper here, see Chapter 2.

76 These 'greater change' features included moving to a service based set of rules and allowing hybrid systems to classify whole integrated resource systems as one 'service provider' as opposed to separate classifications for each unit.

- the benefits of a simple and clear framework created through a single category to accommodate storage and hybrid systems would not be realised if existing registration categories were modified.

DC-coupled systems

The Commission's final decision introduces flexibility in how participants can classify DC coupled systems. It allows proponents of DC coupled systems the ability to choose from four different options for classifying DC coupled systems within an integrated resource system. DC coupled system proponents would register as an IRP and would then have the option to classify the system as either a:

- non-scheduled bidirectional unit (only for systems under 5 MW)
- scheduled bidirectional unit
- semi-scheduled generating unit
- dual classification approach where two units are separately classified as a scheduled bidirectional unit and a semi-scheduled generating unit, and treated as two separate units in dispatch.

Figure A.3 outlines the options for classifying grid scale DC coupled systems.

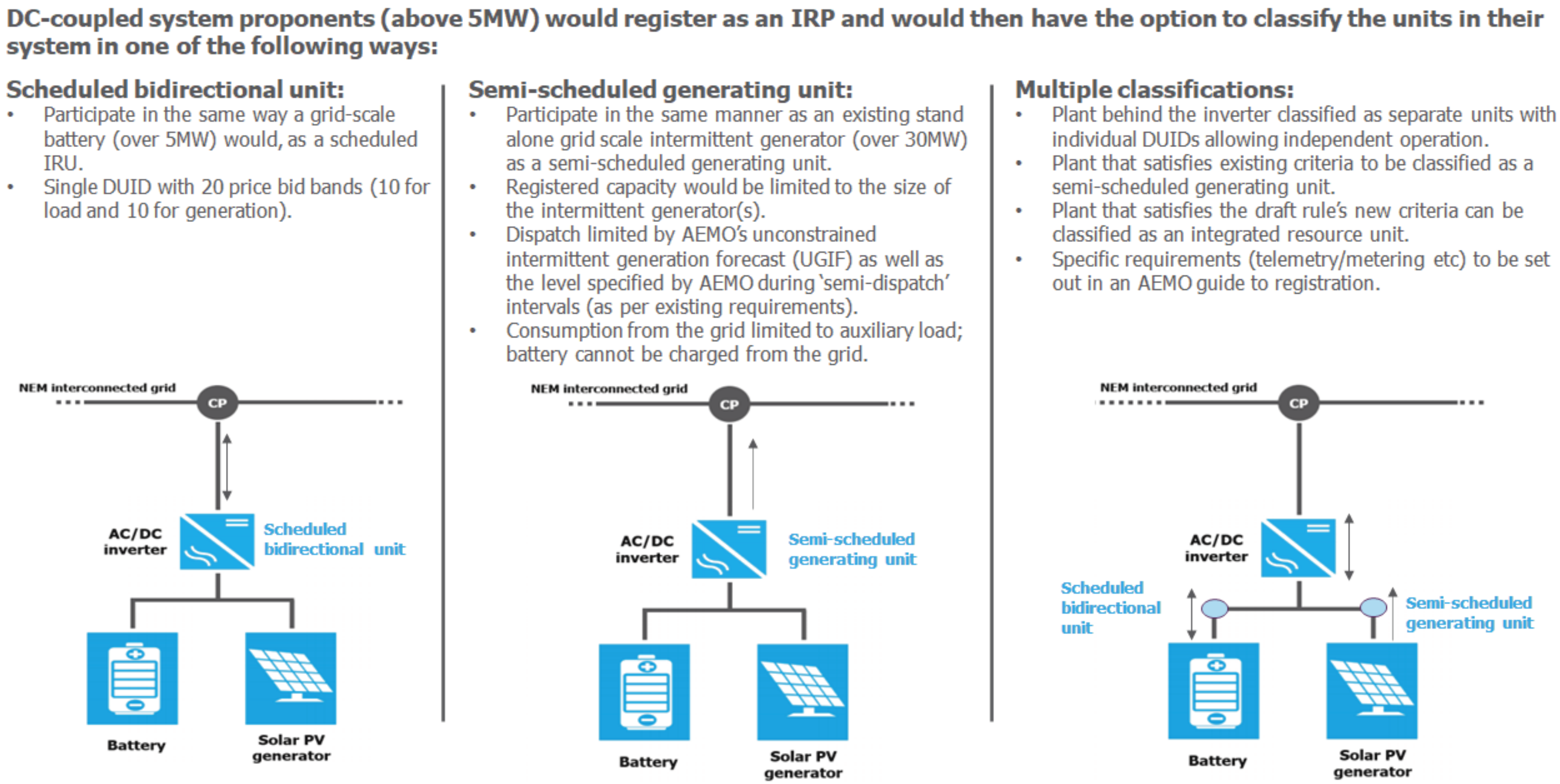
The final decision maintains the draft decision with one amendment to the option of classifying a DC-coupled systems as semi-scheduled, which is to require the registered capacity of the facility to be capped at the size of the intermittent generator(s). This caps the maximum amount of allowed generation to the intermittent renewable energy forecast (for wind or solar, as applicable).

The Commission considers this change still allows participants to install small batteries coupled with renewable generators. This will primarily assist in complying with dispatch and nothing more. This change will ensure storage units that are semi-scheduled cannot operate unconstrained.

AEMO has informed the Commission that it does not intend to allow a DC-coupled system with a storage unit that is 5 MW or above to be classified under the semi-scheduled generating unit option. AEMO considered this would reduce potential operational issues with forecasting generation for DC coupled systems.[77] This would effectively limit the size of a storage unit to under 5 MW if it was DC-coupled and the semi-scheduled classification option was chosen. The Commission considers this approach by AEMO would not materially impact on the uptake of DC-coupled options, and that no additional changes are required to the rules to allow AEMO to take this approach.

77 AEMO noted in discussions with the AEMC that where a storage unit is coupled with an intermittent generator and classified as semi-scheduled, there will exist uncertainty about the proportion of energy provided by the storage unit that feeds back into the forecast model, and the larger this storage unit is the greater the uncertainty in the forecast model output.

Figure A.3: How a grid scale DC coupled facility will register and participate



This diagram is an example of a stand alone DC coupled system. These options could also be used in a hybrid facility. A DC coupled system could vary in the number and type of plant behind the inverter.

Source: AEMC

The Commission considers the benefits of the decision on DC-coupled systems include potential savings on connection costs in the order of 10-20 per cent, as noted in Table A.1, and contribute to achieving the NEO by:

- promoting competition by removing barriers to allow storage greater flexibility in how it can be classified in the market
- improving investor certainty through providing more streamlined rules that accommodate a broader range of business models
- enhancing system reliability and security by better facilitating storage to participate in the NEM and helping increase the proportion of fast-responding dispatchable resources, which are needed to support increasing amounts of renewable generation.

Further analysis and details on DC-coupled systems can be found in the draft determination here, see appendix G, section G.5.

A.3.2 Participation

Central dispatch

The Commission's final decision is to retain the draft decision in how storage and hybrid systems participate in central dispatch, with clarification added to the final rule as to how aggregate dispatch conformance will apply. The key features are:

- Scheduled storage assets (5 MW and above):
  - that can transition between generation and consumption linearly (with no dead band around zero) will participate in central dispatch with a single bidding form and single DUID, and will be labelled as a scheduled bidirectional unit
  - that have a dead band around their zero point of generation/consumption, typically hydro units, will maintain dual bidding forms and DUIDs, one for each of its classifications as a scheduled generating unit and scheduled load.
- Each unit within a hybrid facility will participate in central dispatch separately to the extent required by its classification, but aggregate dispatch conformance will be allowed for hybrid systems except in certain circumstances, as discussed below.
- Market Small Generation Aggregators are permitted to provide ancillary services from the end of March 2023, ahead of the implementation of the remainder of the rule.[78]

Bidding form for storage units

The Commission's final decision is to maintain the draft decision, which is to introduce a new unit classification, the scheduled bidirectional unit, which would participate in central dispatch as a single unit across generation and consumption. The number of price bid bands is maintained at 20 (that is, 10 for the load side and 10 for the generation side of the bidirectional unit).

78 Final rule, new clause 11.145.15.

Some stakeholders questioned if the benefits of this change outweighed the costs. The Commission tested these views with AEMO, and AEMO noted it expects it could implement this approach largely by applying existing functionality, which would minimise the complexity and cost.

The Commission considers the rule is likely to provide a number of benefits which align with the assessment criteria for the rule change, including:

- Minimises administrative and regulatory burden — Reducing administrative cost on AEMO dealing with two separate units. This includes initially in the registration and classification stage but also ongoing in various IT and system processes such as forecasting and constraint formulation.
- Promotes competition — Reduces the set-up costs and ongoing operational complexity of participating in central dispatch for participants.
- Promotes transparency — Transparency of information in the market will increase as storage will be more visible compared to if it was two relatively unrelated DUIDs.

The Commission considers the final rule on bidding provides a simple and clear framework for participants, in alignment with a single registration and classification process. The Commission agrees with AEMO that the current arrangements, in the context of the introduction of the IRP in this final determination, makes participation unnecessarily complex and expensive for AEMO and scheduled storage units. This could create barriers to entry and impact on efficient investment and operation. Consequently, the Commission considers the final rule is in the long-term interests of consumers.

Further background and analysis on bidding can be found in the draft determination here, see appendix B, section B.6.3.

Aggregate dispatch conformance for hybrid systems

The Commission's final decision is to allow hybrid systems the ability to manage their energy flows (i.e. deviate from unit level dispatch instructions) to comply with dispatch in aggregate. However, AEMO will be able to require hybrid facilities to comply with dispatch at the unit level in specified dispatch intervals in certain circumstances, for example where required for stable power system operation.

In response to stakeholder feedback, the final rule provides more clarity on when AEMO may require unit-level conformance with dispatch. The new rule 4.9.2A effectively requires AEMO to consider a more tailored approach to how network constraints apply to hybrid systems; see Box 2 for further detail.

BOX 2: A MORE CONSIDERED APPROACH TO CONSTRAINTS AND HYBRID SYSTEMS

Under the existing approach NEMDE applies all constraints at a DUID level regardless of whether those DUIDs are co-located with load behind a connection point. Using a simple hybrid system with a scheduled generating system and scheduled load behind the same connection point as an example, when a thermal constraint is binding this would mean the scheduled generating system would be constrained down/off, even if the scheduled load would have consumed all of that generation. That is, in aggregate, the hybrid system would not have been exporting energy through its connection point but would still have its generation constrained down and the operator would need to purchase energy from the grid to meet its load instead.

The new rule 4.9.2A will require AEMO to reconsider how constraints apply for hybrid systems and apply these to the aggregate or net flow of energy, other than where the technical attributes of a hybrid system are a factor in AEMO managing the network constraint (in which case unit-level conformance can be specified).

The Commission's final rule intends to achieve the following outcomes, for example:

- When a thermal constraint is binding, a hybrid system would continue to be able to generate and consume energy behind its connection point to the extent it still complies with aggregate dispatch conformance. This is because contributing to a thermal constraint issue is directly related to how much energy is exported at the connection point (and is not affected by the amount of energy generated and used behind a connection point).
- When a system strength constraint is binding, a hybrid system would need to comply with dispatch as instructed for each unit. This is because contributing to a system strength issue is not dependent on how much energy is being exported or consumed at the connection point, but on whether system strength-demanding units are operating (system strength demanding units are otherwise referred to as inverter-based resources). In practice, when a system strength constraint is binding AEMO will constrain down system strength demanding units to allocate more system capacity to generation from system strength providing units.

The Commission engaged extensively with AEMO on this issue and notes AEMO's support for this approach. AEMO will develop further detail on how this approach will be implemented through NEMDE and will include this in its power system operating procedure.

The final rule allows for early application of aggregated dispatch conformance (for systems that include a scheduled or semi-scheduled generating unit and a scheduled load) from the end of March 2023, ahead of the commencement of the remainder of the rule in June 2024.[79]

The Commission considers this final decision will reduce barriers to the integration of storage and hybrids by increasing operational flexibility and reducing curtailed energy. Specifically, this approach would allow a hybrid system operator to:

- Use a storage or generation unit to firm up intermittent generation output up to its semi-scheduled dispatch target. This would allow it to reduce causer pays liabilities. Practically,

79 Final rule, new clause 11.145.16.

this would involve the scheduled bidirectional unit or generating unit exceeding its dispatch target, where this action does not impact FCAS enablement or response, to firm up a semi-scheduled generating unit.

- Exceed a unit's semi-scheduled dispatch target to charge a storage unit within a hybrid facility, for example if:
  - forecast output is lower than actual output
  - it is constrained off from exporting to the grid
  - prices are negative.
- Continue to allow a scheduled load or bidirectional unit to consume generation behind a connection point when some constraints are applied, as this constraint would apply to the net sent out energy from the hybrid system.

Further background and analysis on aggregate dispatch conformance can be found in the draft determination here, see appendix B, section B.6.3.

Aggregators providing energy and ancillary services

The Commission's final decision is to retain the draft decision, which is to:

- Require no additional scheduling or central dispatch participation obligations on aggregators of small units, in relation to energy. The current approach for MSGAs' small generating units to be non-scheduled will be maintained for aggregators of small generating and storage units, who will be transitioned into the IRP. The longer term path for the trader-services model will consider how this may change in the future.
- Allow aggregators of small generating units and/or storage units to provide market ancillary services from generation and load.

In response to stakeholders' requests for clarity, the Commission notes the following:

- this final rule will continue to allow retailers to operate VPPs
- where community batteries are used to compete in contestable markets (providing energy and FCAS) they will need to be operated by a market participant (such as a retailer) rather than the DNSP
- interested parties may contact AEMO for further information in relation to scheduling and operational requirements for FCAS provisions from VPPs and community batteries.

Further background and analysis on aggregators providing ancillary services can be found in the draft determination here, see appendix B, section B.6.3.

Ramp rates and aggregating semi scheduled units

The Commission's final decision is to allow one aggregation approach for semi-scheduled generating units and storage systems, reflected in NER clause 3.8.3. The Commission agrees that it is appropriate for the NER to allow AEMO the discretion to consider whether different technology types can be aggregated for dispatch under Chapter 3 of the NER (noting the separate provisions on aggregate conformance with dispatch, discussed above; where there is aggregated conformance under clause 4.9.2A(b), AEMO still provides dispatch instructions to each unit).

The Commission's final decision retains the draft decision, which is to set a minimum ramp rate at the lower of 3 MW or 3 per cent of scheduled load capacity and remove the 6 MW threshold for aggregating semi-scheduled units in NER chapter 2. For participants with the same number of units and total MW capacity, this would see a consistent method for setting the minimum ramp rate for:

- storage and non-storage participants
- load and generation units
- scheduled and semi scheduled units.

The Commission considers setting minimum ramp rates in this way will have the following benefits:

- set a more level playing field for scheduled generation and load
- make storage participation less complex
- allow semi-scheduled participants to aggregate units above 6 MW
- better align with the longer-term two-sided market vision (more consistent treatment of load and generation).

This a minor change from draft to final rule to clarify that an IRP can set different ramp rates for load side & generation side of a bidirectional unit.[80]

Further background and analysis on ramp rates and aggregating semi scheduled units can be found in the draft determination here, see appendix B, section B.6.3.

Bidding parameters and forecasting

The Commission's final decision would continue to require each unit, regardless of whether it is standalone or in a hybrid facility, to provide forecast information into the pre-dispatch, short-term and medium-term PASA processes, to the extent that is required by its classification (as scheduled, semi-scheduled or non-scheduled).

This final decision does include minor amendments from draft to final based on stakeholder feedback. These amendments are:

- The removal of draft rule clauses 3.7.3(e)(5) and 3.8.4(c)(3A) that would have required energy constrained scheduled bidirectional units to provide forecast energy availability per interval. Taking into account stakeholder feedback, the Commission considers these requirements may be impractical for storage units to meet as well as having the potential to create compliance issues.
- The amendment of existing clauses 3.7.3(e)(4), 3.8.4(c)(3) and 3.8.6(g2) to require energy constrained scheduled bidirectional units to provide daily energy availability (as storage units currently do as scheduled generating units).

80 Final rule, new clause, 3.8.3A(b).

A.3.3 Generator performance standards

The Commission's final decision retains the draft decision, which is to maintain the existing approach of setting performance standards at the connection point. An IRP will have a single performance standard apply to its facility. However, this performance standard would reflect the technical and performance capabilities of each unit behind the connection point. This approach provides clarity on how performance standards will apply to stand alone storage and hybrid facilities without any significant policy changes to the way in which standards are currently established and applied under chapter 5 of the NER. This approach is consistent with AEMO's proposal and is generally supported by stakeholders. The next section provides a worked example of how a hybrid system's performance would be assessed.

An example of how a hybrid system's performance standards would be assessed

The below scenario demonstrates how performance standards are intended to be assessed for a hybrid system.

A generating system or integrated resource system is required to have capabilities to meet an agreed level of performance, which will depend on whether the system is:

- meeting the automatic or minimum access standard
- a scheduled, non-scheduled, or semi-scheduled unit
- synchronous or asynchronous.

A hybrid system that has both a scheduled bidirectional unit (e.g. a battery) and a semi-scheduled generating unit (e.g. a wind farm) will have technical requirements set and assessed against both units or either unit, depending on the hybrid system's operating mode. This hybrid system has three operating modes (when at least one unit is operating):

1. both the battery and wind farm are operating
2. only the battery is operating
3. only the wind farm is operating.

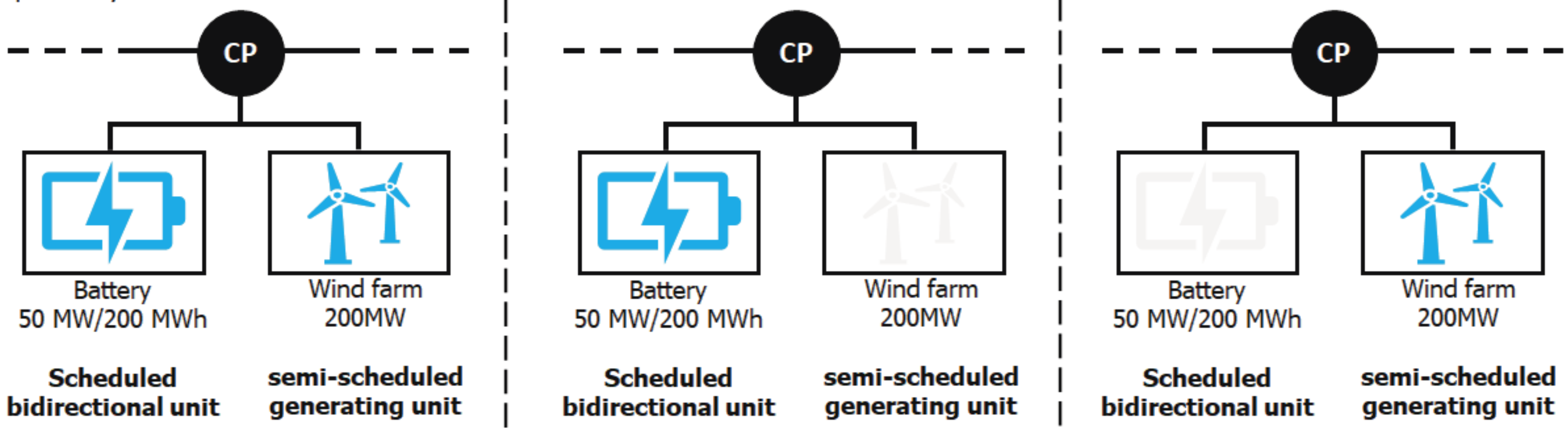
Figure A.4 outlines the hybrid system's operating modes and describes how its performance would be assessed.

Figure A.4: An example of how a hybrid system's performance would be assessed against its performance standards

In the mode where **both** the battery and wind farm are in service, the performance will be assessed against a composite response corresponding to the agreed performance of both the scheduled bidirectional unit and semi-scheduled generating unit. That is, AEMO would consider the requirements together at the point of obligation, as well as measure them separately.

In the mode where **only the battery** is in service, the performance will be assessed against the requirements for a scheduled bidirectional unit. That is, AEMO would only consider the requirements for the battery at the point of obligation.

In the mode where **only the wind farm** is in service, the performance will be assessed against the requirements for a semi-scheduled unit. That is, AEMO would only consider the requirements for the wind farm at the point of obligation.



Source: AEMC

Concerns raised and clarity sought by stakeholders on re-registration and performance standards

The Commission notes concern expressed by existing storage participants in relation to the requirement to change registration categories and whether this may pose a risk of re-opening their connection agreements and generator performance standards. The Commission does not intend for the change in registration to create these risks, and has clarified this in the transitional rules.[81]

In response to stakeholders seeking clarity in relation to performance standards, the Commission notes:

- It sought expert advice to ensure that changes made to Chapter 5 of the NER (which includes the provisions for connecting IRPs and bidirectional units to the network and setting their performance standards) to incorporate the new category and classifications do not change outcomes unnecessarily or result in unintended outcomes. Our technical experts considered that there are no unreasonable performance expectations placed on loads that are part of hybrid systems.
- For the purpose of setting and assessing performance standards, DC-coupled systems will be treated according to their chosen classification: as a semi-scheduled generating unit, a scheduled bidirectional unit, or both where they choose the dual classification option.
- Where an existing Generator wants to add a battery to its generating system (whether through having a separate inverter or creating a DC-coupled system) it will be changing the characteristics and technical capability of its system. The final rule maintains the existing arrangement where this type of activity would trigger NER clause 5.3.9, which is the procedure to be followed by a Generator proposing to alter a generating system. This issue is being considered as part of the Connection Reform Initiative, jointly sponsored by AEMO and the Clean Energy Council.[82]

A.3.4 Implementation, cost and benefit considerations

All changes made by the final rule, except those noted below, will come into effect 30 months and one day after the final determination is published - that is, 3 June 2024. The changes that will come in earlier have transitional rules to allow their implementation on 31 March 2023. These are:

- Allowing aggregators of small generating units (including small storage units) to provide ancillary services.[83]
- Allowing hybrid systems to use aggregate dispatch conformance.[84] While the IRP category will not be available until June 2024, participants will still be able to register hybrid systems and classify their units under the existing framework.

81 Final rule, new clauses 11.145.5 and 11.145.14.

82 For the latest on the Connection Reform Initiative, the web page can be accessed here.

83 Final rule, clause 11.145.15.

84 Final rule, clause 11.145.16.

Implementation to be completed by June 2024

In submissions to the draft determination, stakeholders considered some changes should be prioritised and brought forward as soon as possible, but AEMO considered that 18 months would be insufficient for it to implement all the changes set out in the draft determination.[85]

The Commission engaged further with AEMO to understand what changes could be implemented earlier, and subsequently AEMO has provided a letter outlining that it recommends an implementation timeline of 30 months.[86] AEMO considered that, under its recommended approach, the final rule would be implemented through two releases:

- A baseline release by 31 March 2023, which will include the main components of the registration and dispatch functionality, and changes to allow SGA to be ancillary service providers, but noted the latter was subject to further consideration through the detailed planning phase of work.
- A final release on 3 June 2024, which will consist of retail and settlement systems, as well as full integration of all market systems. AEMO also noted it will run a market trial from February to May 2024 to provide an opportunity for participants to test changes to registration, bidding and dispatch prior to the commencement of the rules.[87]

AEMO identified the main drivers of a two and half year implementation timeline are:

- **Concurrent projects**. The existing pipeline of work for retail and metering systems is the key constraint driving the timing of the delivery of the IESS rule change. Concurrent retail and metering projects include:
  - Global Settlements (GS)
  - Metering coordinator planned interruptions (MCPI)
  - Market Settlement and Transfer Solutions (MSATS) Standing Data Review
  - Stand-Alone Power Systems (SAPS)
  - Consumer data right (CDR)

  AEMO noted a number of the changes made by the final rule will need to be staggered one after another. That is, the concurrent changes to AEMO's processes and systems means that the development of the metering solution cannot commence until May 2022 following the completion of the GS project. In turn, the settlements solution cannot commence until the metering solution has been completed.[88]
- **Project dependencies**. AEMO has identified a number of direct dependencies that need to be considered when planning the final rule implementation, including the:
  - STPASA redevelopment project as well as other changes to the bidding and dispatch systems are co-requisites to this rule change

85 AEMO, submission to the draft determination, p. 1.

86 AEMO's supplementary letter to this rule change regarding implementation can be accessed on the project page here.

87 AEMO's supplementary letter to this rule change regarding implementation can be accessed on the project page here.

88 AEMO's supplementary letter to this rule change regarding implementation can be accessed on the project page here.

- registration model developed by this rule change will be a co-requisite to Flexible Trading Arrangements (FTA), Scheduled Lite, Fast Frequency Response and other ESB initiatives.

AEMO noted it will adopt a tranche delivery approach where a 'baseline' release on 31 March 2023 will allow for dependent initiatives to build upon the functionality delivered in the IRP registration model. The complex set of dependencies requires careful planning and well considered solution design to minimise the delivery risk associated with the implementation project.[89]

The Commission notes that while it is imperative that these changes are introduced as soon as possible, it recognises the wide range of changes that are happening and dependencies between current and future reforms. The Commission agrees with AEMO's proposed implementation plan and notes that it is important for the final rule to be implemented thoughtfully and with consideration of the broader regulatory reform road map.

Costs and benefits

AEMO provided a cost estimate for the draft decision to introduce the IRP and make changes to the registration and participation framework, of $14 million to $21.7 million.[90] This cost estimate has not been revised for the final determination. The Commission considers the benefits of these reforms are likely to outweigh the costs and will therefore promote the NEO. In the current circumstances, they are the best combination of reforms to integrate storage and hybrid facilities into the market. Table A.1 shows a breakdown of the costs and estimated benefits associated with each design feature.

89 AEMO's supplementary letter to this rule change regarding implementation can be accessed on the project page here.

90 This does not include the $5 million to $7 million cost estimate for implementing changes to the recovery of non-energy cost framework, which is presented in Appendix B.

Table A.1: **Estimated cost of implementing the final for registration and participation**

DESIGN FEATURE	AEMO'S ESTIMATED COST RANGE	ESTIMATED BENEFIT
New participant category	$8 to $10 million —This is the original and lowest cost estimate from AEMO to introduce a new bidirectional market participant category. This cost is necessary to set up a new category that specifically caters for participants with bidirectional energy flows, minimises the administrative burden that currently exists for storage participants and allows hybrid facilities to register and participate.	This change would also: • enhance system reliability and security as it would encourage and promote the entry of new storage capacity that would help to firm up the growing amount of renewable energy in the market • allow greater flexibility in how small storage units can be used in the market • align with the possible future direction foreshadowed by the ESB towards a trader-services model.
Increasing number of bid bands for IRPs to 20	$1.5 to $2 million	Moving to 20 bid bands for IRPs would allow a level playing field for storage participants as they will have 10 bid bands for each of their load and generation, the same as other scheduled load and scheduled or semi-scheduled generators. Recognising storage as a single bidirectional unit also complements a simplified registration and classification process through the IRP.
Allowing flexibility for DC coupled systems to register and participate	$1 to $2.5 million	Participants have noted that, by allowing DC connected systems (rather than registering and connecting a renewable generator and battery separately), there are savings in the order of 10 to 20 per cent for setup and connection costs. Setting up a clear framework for hybrid systems to register and participate in the market is important as it is anticipated hybrid systems will become increasingly common.

DESIGN FEATURE	AEMO'S ESTIMATED COST RANGE	ESTIMATED BENEFIT
Moving SGAs into the IRP and allowing them to participate in the ancillary services market	$1 to $2 million	This change would send clearer investment signals in allowing aggregators of small generating and storage units to provide more services, including the ability to provide ancillary services. It is a relatively low cost change that will allow more participants access to more revenue streams, and deliver services the market needs. This change aligns with an important element of the ESB's two-sided market work on developing a universal participant category (trader-services model) and establishing flexible trading arrangements.
Amending Generator Performance Standards for integrated resource units	$0.5 to $1 million	This is a relatively low cost that is necessary to integrate and allow storage and hybrid systems to connect to the system and participate in the market
Review of AEMO's procedures and guidelines	$0.5 to $1 million	This is a relatively low cost that is necessary to review and update AEMO's procedures and processes to implement the Integrated Resource Provider participant category and bidirectional unit classification.
Other system changes needed for this rule change that also set up flexibility to implement post-2025 reforms	$1.5 to $3.2 million Note: Some of these costs could be attributed to other design features, but it is not always possible to break out costs that are incurred because of a number of changes.	Incurring these costs now, as part of this reform, sets up some systems more efficiently for the flexibility needed to implement further post-2025 reforms. Future changes that fall out of the ESB work would be simpler and cheaper to implement.

Source: The costs have been provided by AEMO. The benefits have been developed through AEMC analysis, including stakeholder feedback.

A.4 Background information

Further background and analysis on the registration and participation can be found in the draft determination here as follows:

TOPIC	SECTION OF APPENDIX C
How registration, classification and participation occurs in the NEM	B.2
Issues and proposed solution raised by AEMO	B.3 and B.4
Previous stakeholder feedback	B.5
The Commission's draft determination analysis	B.6

B RECOVERY OF NON-ENERGY COSTS

BOX 3: FINAL RULE — RECOVERY OF NON-ENERGY COSTS

The final rule amends the non-energy costs recovery framework so that recovery is based on a participant's gross consumed energy and/or gross sent out energy in an interval across its connection points. This is irrespective of the participant category in which it is registered. The final rule removes the ability for a participant to net energy flows at a connection point or among its connection points.

Benefits of the final rule

The final rule will remove inefficient outcomes that may favour participants with large bi-directional energy flows and create a more level playing field for all participants, including storage and hybrid facilities.

B.1 Overview

The Commission's final rule retains the draft rule, which will remove inefficient outcomes that may favour participants with large bi-directional energy flows and therefore create a more level playing field all participants, including storage. The final decision aligns with the Energy Security Board's two-sided market work as it looks to treat all participants based on their interactions with the market.

In its rule change request, AEMO identified that non-energy cost recovery is inconsistent between grid-scale storage and other participants including small storage participants. This is because, currently, the recovery of non-energy costs for:

- grid-scale storage is based on registration in two categories (market customer and market generator), and separately measured energy flows that are not netted
- small storage participants is based on registration in the MSGA category, and a single measurement of net metered energy flow.

AEMO considered that this inconsistency creates inefficient outcomes that includes the ability for MSGA participants to reduce their share of non-energy costs compared to a grid-scale storage participant. AEMO also noted that the existing framework may:

- Provide incentives to register in certain participant categories to avoid the financial cost of non-energy services, and potentially other services like DUOS.
- Result in the burden of non-energy services being borne by customers that cannot afford to own and connect 'exempt' generating units or storage systems behind their connection point. This would be made worse if the base of registered participants to recover costs from diminishes further.

The Commission agrees with AEMO that there is an inconsistency with how non-energy costs are recovered from all participants due to the increasing amount of bidirectional energy flows. The Commission notes that some participants with bi-directional energy flows can reduce their share of non-energy costs through netting. This increases the share paid by other participants who do not have bidirectional energy flows.

The Commission's final decision is to amend the non-energy costs recovery framework so recovery of these costs is based on a participant's gross consumed energy and/or gross sent out energy in an interval (as applicable), irrespective of what participant category they are registered in. The Commission has made one amendment from the draft to final decision. That is, to remove demand response service providers from being liable for non-energy costs as they are not financially responsible market participants.

This appendix discusses the following, in relation to non-energy costs:

- stakeholder feedback to draft determination
- the Commission's analysis and final decision
- background information.

B.2 Stakeholder feedback to the draft determination

Stakeholders were generally supportive of the draft changes to the recovery of non-energy costs. Some stakeholders proposed that more needs to be done to remove inequity issues in how these costs are recovered. One stakeholder did not support aspects of the draft changes.

Those stakeholders who supported the draft decision considered these changes would:

- create an effective, enduring solution for an increasingly bidirectional power system[91]
- more clearly link costs to how a participant interacts with the system, not the registration category[92]
- are a long-term solution for both the settlement and low demand issues raised in other AEMO and Infigen rule changes.[93]

While supportive of the draft changes which reduce the inequity issues, a number of stakeholders considered more needs to be done to address the inequity issues will still be present in how non-energy costs are allocated.

- Some stakeholders supported a broader review of how non-energy costs are allocated.[94]
- Shell considered that the threshold for minimum demand when calculating non-energy cost brought in by the rule change, NEM settlement under low, zero and negative demand conditions needs to be enduring to avoid inequitable outcomes.[95]
- Neoen noted the draft changes are welcome, but argued that by continuing to allow netting of energy flows behind a connection, a participant can reduce their liability in

91 Submissions to the draft determination: Flow Power, p. 2; Origin Energy, p. 3; EnergyAustralia, p. 6.

92 Submissions to the draft determination: SA Dept of Mining and Energy, p. 2; Yes Energy, p. 1; Stanwell, p. 1; Alinta Energy, p.2; Endeavour Energy, p. 1; Fluence, p. 4.

93 Submissions to the draft determination: SA Dept of Mining and Energy, p. 2; CEIG, p. 2; EnergyAustralia, p. 6.

94 Submissions to the draft determination: AEC, p. 4; Bay Wa, p. 2; Iberdrola p. 7.

95 Shell, submission to the draft determination, pp. 10-11.

paying for the costs that are recovered but it does not reduce their contribution to the need for the non-energy services provided.[96]

Enel X did not support two aspects of the draft changes as it appeared it would create outcomes that saw customers double-charged for non-energy costs:

1. demand response service providers should not be *Cost Recovery Market Participants* as they are not financially responsible for the connection point and the final rule on the Wholesale demand response rule change determined that demand response service providers would not be liable for FCAS costs
2. child connection points should not be liable for recovery of non-energy costs as the parent connection point is already incurring these costs.[97]

B.3 The Commission's analysis and final decision

The Commission's final decision maintains the draft decision with one minor amendment (and a limited number of drafting corrections). The minor amendment is to remove demand response service providers from the definition of cost recovery market participants. That is, to maintain the existing approach where demand response service provides are not liable for the recovery of non-energy costs.

The final decision amends the non-energy costs recovery framework to align with the overarching principle that recovery of these costs should be on a beneficiary/causer pays approach, or if that is not possible then costs should be dispersed as broadly as possible. Therefore, the recovery of non-energy costs will be based on a participant's gross consumed energy and/or gross sent out energy in an interval (as applicable), irrespective of what participant category it is registered in. Consumed and sent out energy will be measured separately for all market participants i.e. consumed and sent out energy data in an interval will be measured separately and not netted among different connection points nor at a single connection point in any interval during which energy has been both sent out and consumed.

This approach will not count energy that is both produced and consumed behind the connection point for the purposes of calculating non-energy costs, for example, rooftop solar production that is consumed on site.

This decision requires two main changes:

- The use of two new data streams in non-energy cost recovery — adjusted sent out energy (ASOE) and adjusted consumed energy (ACE), which will be available after global settlement is implemented in May 2022 where the necessary metering is in place.
- Non-energy cost recovery would be based on a participant's gross energy flows i.e. gross consumed (i.e. ACE) or exported (i.e. ASOE) during relevant intervals, rather than the category a participant is registered in.

This final rule will replace the interim solutions that were implemented under:

96 Neoen, submission to the draft determination, p. 4.
97 Enel X, submission to the draft determination, pp. 3-4.

- AEMO's rule change NEM settlement under low, zero and negative demand conditions[98]
- Iberdrola's (then Infigen) rule change Settlement under low operational demand.[99]

The following sections address stakeholder feedback on the draft determination.

Stakeholders support further work on the recovery of non-energy costs

The Commission notes a number of stakeholders argued that even with the draft decision inequities still exist in the approach to recovering non-energy costs. This is because participants with both generation and load behind a connection point are able to reduce their share of the non-energy costs recovered.

The Commission considers the primary objective of this rule change is to better integrate storage and hybrid facilities into the NEM. The final rule achieves this by realigning the non-energy costs recovery framework to create a consistent approach for all participants.

Further, the Commission considers:

- This rule change has only engaged stakeholders on how to share the existing allocation of costs, not on changing the allocation of costs between the supply and demand sides of the market, or basing the recovery of these costs on behind the meter energy flows.
- It is not appropriate to retain the 150 MW threshold (as suggested by Shell, see appendix B.2). This was only intended as an interim measure and the Commission has not engaged on or assessed this approach as a long-term solution.
- Future work could focus on looking at how each of the non-energy costs should be allocated, including the option to separate energy flows behind a connection point when calculating who benefits from the provision of non-energy services.
- This work is not currently a part of the AEMC's priority work program.[100] Stakeholders should consider if, how and when this issue should be addressed.

Demand response service providers removed from the definition of cost recovery market participant

The Commission agrees with the arguments put forward by Enel X and has removed demand response service providers from the definition of cost recovery market participants. The Commission notes:

- demand response service providers are not the financially responsible market participant for their connection point
- this change ensures non-energy costs are not double-charged, and are only recovered from the financially responsible market participant.

Non-energy costs in embedded networks

The Commission has tested Enel X's view (see appendix B.2) with AEMO, and considers that embedded network arrangements with parent and child connection points are not being

98 This rule change can be accessed here.

99 This rule change can be accessed here.

100 The AEMC's priority areas of reform can be accessed here.

double charged for non-energy costs, and nor will the final rule result in double charging. The Commission notes that:

- The calculations of adjusted sent out energy and adjusted consumed energy are based on the amount of electrical energy flowing to or from a transmission network connection point in a trading interval, as recorded in the metering data in respect of that connection point and that trading interval.
- The types and configurations of metering installations at the parent and child connection points on embedded networks, and the subtractive or other arrangements used in those metering installations, must be maintained by the embedded network manager under clause 7.5A.2 of the NER.
- The metering provisions in the NER provide sufficient flexibility for market participants that are financially responsible for child or parent connections points to establish metering arrangements with the embedded network manager. This allows for recovery of non-energy costs on the basis of the amount of energy consumed or generated for which the market participant at the relevant connection point is financially responsible.

B.3.1 Implementation and cost

As noted in Chapter 2, the final rule will come into effect 30 months and one day after the final determination is published, that is 3 June 2024.

There are still a significant number of Type 6 accumulation metering installations, AEMO estimates up to 8.5 million across the NEM, which cannot separately measure bi-directional energy flows. Under the final rule these sites would continue to have non-energy cost recovery calculated on net energy flow, until meters are replaced with smart meters.

AEMO provided a cost estimate of $5 million to $7 million for the changes to the recovery of the non-energy costs framework. The Commission considers the benefits of removing inefficient cross subsidies and providing a long-term solution to the settlement issues raised in the AEMO and Infigen rule changes mentioned above, are likely to outweigh the cost to implement these changes to the framework for the recovery of non-energy costs.

B.4 Background information

Further background and analysis on the recovery of non-energy costs can be found in appendix C of the draft determination here as follows:

TOPIC	SECTION OF APPENDIX C
Non-energy costs	C.2
Issues and proposed solution raised by AEMO	C.3 and C.4
Previous stakeholder feedback	C.5
The Commission's draft determination analysis	C.6
How this final decision will impact on the different categories of non-energy cost	C.7

C NETWORK USE OF SYSTEM CHARGES

BOX 4: FINAL RULE — NETWORK USE OF SYSTEM CHARGES FOR STORAGE

The final rule makes minor amendments to transmission network charging arrangements

The new IRP participant category will be a Transmission Customer for the purposes of NER Chapters 5 and 6A in relation to electricity taken from the grid. An IRP is therefore required to decide whether to seek a prescribed transmission service and pay the associated charges, or a different level of service under the framework for negotiated shared transmission services.

The final rule reduces barriers to the use of negotiated shared transmission services. Where a connection applicant seeks a shared transmission service and jurisdictional legislation is, or may be, an impediment to the provision of a negotiated transmission service, the Transmission Network Service Provider (TNSP) must, where requested:

1. provide information to the connection applicant about the nature of the issue and how it may be addressed; and
2. provide reasonable assistance with any governmental or regulatory approvals or coordination with the jurisdictional planning body required to address the issue.

The final rule amends distribution network charging arrangements

Amendments relate to the application of NER Chapter 6 pricing principles to non-retail distribution customers under the tariff structure statement process (including the objective that tariffs should reflect efficient costs).

This appendix sets out the Commission's analysis, final decision and stakeholder views on the draft determination relating to network use of system charges for storage. Additional information and background on network charges can be found in appendix D of the draft determination, which can be accessed here.

C.1 Overview

We are retaining the current framework on network charges

Our final decision retains the current framework to allow storage to connect under a negotiated agreement for any network charges.[101] We consider that a change to the current framework that would exempt storage would not promote the NEO as it would not send storage proponents and operators price signals that reflect:

- the efficient cost of providing network services

101 Storage may choose between a prescribed service or to negotiate. To date, all storage have connected under a negotiated agreement

- the benefit storage may have on the network (where a cost-reflective charge may result in storage being paid for the benefits they provide at certain times).

The Commission notes that the default position is not that storage must pay network charges, including TUOS. Rather, storage participants can choose the service they need and whether they go through the process of obtaining a negotiated or prescribed shared transmission service.

In maintaining the current framework, the Commission's final rule does make minor amendments to the NER to clarify how the negotiated framework applies in relation to grid-scale storage and hybrids, and to accommodate the new IRP participant category. It also reduces barriers to the uptake of shared transmission services on a negotiated basis.

AEMO proposed to define storage and exempt storage from TUOS charges

In its rule change request, AEMO considered that there was a lack of clarity on how network use of system charges apply to grid-scale storage and hybrids because they are not defined in the NER.[102] To address these issues, AEMO proposed to define storage and exempt it from TUOS charges. AEMO considered that an exemption would increase investor certainty and eliminate inefficient storage location decisions.

AEMO did not propose a similar exemption for storage connected at the distribution level from paying distribution use of system (DUOS) charges.[103]

Our draft decision did not define storage or exempt storage from network charges

The draft rule did not define storage and kept the current framework for how load and generation face network charges. However, it did make minor amendments to clarify the current arrangements. The Commission received extensive feedback on the draft rule, while network businesses, the Australian Energy Regulator (AER), SA government and the MEU supported the decision, many others including storage proponents and operators strongly opposed it.

Further work is needed on network charging issues

The pricing of transmission services should be considered as the energy market transitions to more storage and other large flexible load (e.g. hydrogen). This includes determining the most efficient approach that sends the right price signals to storage to locate in the right areas, use the network and provide network services at the right times, and reward storage for doing so. As noted in appendix C.1.4, the Commission anticipate a rule change will be submitted to address these issues, and it will prioritise this work.

C.1.1 Benefits of the final rule

The Commission considers that the decision to maintain the current framework with amendments to support the negotiation of charges with TNSPs has the following benefits:

102 AEMO Integrating Energy Storage Systems into the NEM rule change request, 23 August 2019, p. 20.

103 Ibid, p. 29, 54.

- improves clarity on the treatment of distribution and transmission network charges for storage
- retains the flexibility for storage applicants to choose between negotiated and prescribed agreements for shared transmission services
- reduces barriers to the uptake of shared transmission services on a negotiated basis
- provides certainty to existing storage proponents. While existing storage will be transitioned across to the new IRP participant category, no changes will be made to existing network charging arrangements, allowing existing negotiated arrangements to remain in place.

C.1.2 The Commission does not intend the move to the IRP will impact current agreements

Under the decision relating to registration, existing storage participants, both transmission and distribution-connected, will need to move to the IRP category.[104] However, the intent of this decision is that the shift to the new category would not change existing connection agreements (including existing network services or charging arrangements) as specified in clause 11.145.18. The Commission understands that many storage proponents have negotiated very low or zero network charges with the TNSP, and does not consider that any changes made in this rule change should alter those agreed charges.

C.1.3 New storage participants

New transmission–connected storage participants will be able to negotiate arrangements with TNSPs in the same way existing storage participants have. The Commission expects that, in accordance with the NER, TNSPs will negotiate price and service levels that are consistent with those that have been negotiated for existing storage participants.

New storage participants who choose to connect to the distribution network will receive a direct control service tariff or a storage tariff trial option, where offered.

C.1.4 Further work is needed to investigate network charging issues for storage and other large flexible loads

The Commission notes that the existing rules relating to prescribed transmission service tariffs were not designed for loads like storage that can respond to dynamic price signals and can be controlled to minimise their impact on, or indeed reduce, network congestion. The existing negotiated services framework accommodates these types of loads without imposing prescribed TUOS charges. However, there are broader issues still to be considered, including how to better provide network price signals to incentivise efficient operation and location signals to storage operators and investors.

The Commission considers that these broader issues would need to be considered in relation to network charges more broadly and this rule change is not the appropriate avenue to address these substantial and complex issues. The Commission notes that these issues are relevant for other large flexible loads (e.g. hydrogen) which are entering the NEM. Changes

104 Final rule, new clause 11.145.2.

to the Rules should be technology-neutral and thereby provide efficient price signals to all such loads, rather than specific regulations for storage.

The Commission considers this is an important issue that needs to be addressed and further work is needed on providing efficient network prices signals to storage and other market participants to support the energy market as it transitions to more renewables. Some stakeholders have indicated to the Commission they will submit a rule change on this issue following the final determination. The Commission agrees this is the right approach to dealing with such a significant reform area and anticipates a separate rule change request from interested participants that would allow us to consider these issues in more depth. The Commission will prioritise any such rule change request in the 2022-23 financial year.

The Commission also notes that other reforms may need to be considered alongside a future rule change, including:

- the ESB's recommended Congestion Management Model-Renewable Energy Zone (CMM-REZ) which proposes to put in place real time dynamic pricing to reflect the locational price of using the transmission network
- the AER's review of the transmission ring-fencing guidelines which is expected to be started in 2022.

C.2 The Commission's analysis and final decision on transmission network use of system charges

This section provides:

- a summary of stakeholder feedback on the draft rule that retained the current arrangements, with minor amendments
- an explanation of why the final determination does not exempt storage participants from going through the usual process of obtaining a shared transmission network service
- an explanation of why the final determination retains the current arrangements and makes a minor amendment to improve the negotiating process for shared transmission services
- a summary of other reform processes that will work alongside the final rule by improving signals for efficient investment and use of the electricity network.

C.2.1 Summary of stakeholder feedback on the draft rule that retained the current arrangements, with minor amendments

The draft rule retained the current arrangements and made minor amendments to provide additional clarity. Additional information can be found in the draft determination here, see appendix D, section D.6.

The key stakeholder feedback on the draft rule is summarised below.

- Many stakeholders, including storage proponents and operators, did not support the draft rule. Generally, these stakeholders preferred one of the following outcomes:

- a full exemption from network charges for transmission connected storage participants[105]
- introducing more cost reflective services[106] with lower performance standards and lower tariffs, such as an interruptible service for transmission connected storage and other scheduled loads.[107]

- Network businesses, the AER, South Australian Government and the MEU supported the draft rule as it allowed storage to connect and negotiate an outcome that reflected their impact on the network.[108] The AER and ENA did not consider that a blanket exemption on network charges was appropriate for transmission connected storage.[109]

More detail on stakeholder feedback on the draft rule is provided in appendix C.2.2, appendix C.2.3 and appendix C.2.4.

C.2.2 The final rule does not exempt storage from the process of obtaining a shared transmission network service

The final rule retains the draft rule to not exempt storage from network charges. This means that storage participants can choose whether to seek a prescribed or negotiated transmission service, and follow the relevant pathway for the determination of any charges, noting that negotiated charges may be set at zero.

Many stakeholders, including storage proponents and operators, considered that the rules should specify that storage is exempt from paying TUOS for a number of reasons. The Commission's analysis in response to these reasons is outlined below.

A blanket exemption of storage from network charges would not be cost reflective or technology neutral

The Commission's position is that it is important for the rules to adopt a technology-neutral approach and not create cross subsidies. Incentivising the uptake of particular technologies or the provision of particular services is best determined by governments as an overlay to the technology-neutral framework the NER seeks to provide.

Stakeholder views on this were mixed. For example, Tesla suggested that the application of network charges for storage creates a cross-subsidy to end consumers of energy.[110] On the other hand, Endeavour Energy considered that exempting storage from network charges, as a default position, would require "networks to initiate a process to unwind cross-subsidies that are introduced from the outset."[111]

105 Australian Energy Council, p. 1; AGL, p. 1; Alinta, p. 2; AEMO, p. 19; ARENA, p. 1; ATCO, p. 1; BayWa, p. 1; CleanCo, p. 1; EnergyAustralia, p. 1; Flow Power, p. 1; Clean Energy Investor Group, p. 1; Hydro Tasmania, p. 1, Iberdrola, p. 1; Meridian, p. 1; Neoen, p. 2; Origin, p. 1; Snowy Hydro, p. 2; Stanwell, p. 1; Tesla, p. 4; Tilt Renewables, p. 1; Windlab, p. 1

106 Akaysha submission, p. 1.

107 Shell Energy submission p. 1.

108 Submissions on draft determination from: AER, p. 1; AusNet Services, p. 2; Energy Networks Australia, p. 1; SA Department of Energy and Mining, p. 3; Major Energy Users, p. 3; Endeavour Energy, p. 1; TasNetworks, p. 1

109 Submissions from AER, p.1; ENA, p. 1.

110 Tesla submission, p. 3.

111 Endeavour Energy submission, p. 2.

Our final position is not to provide a blanket exemption from network charges. The Commission considers that AEMO's proposed technology specific exemptions will not contribute to the NEO. A blanket exemption would not reflect the efficient cost of providing the service to a bi-directional unit or the benefit or cost impact it may have on the network.

Other reforms will also seek to provide a level playing field for all participants by focusing on services rather than the technology that provides it, including the ESB two-sided market design and the CMM-REZ. More information on the CMM-REZ is set out in appendix C.2.4.

Exempting storage from network charges would not support efficient location decisions

Exempting storage from network charges, as proposed by AEMO, would not address concerns about the potential for inefficient locational or operational decisions made by storage. However, other reform processes outside of this rule change, detailed in appendix C.2.4, may address AEMO's concerns by providing more efficient and consistent network charges for storage.

The MEU considered that storage should pay for its use of the network as it may cause "a need for augmentation of the network to accommodate its peak import demands".[112] On the other hand, AusNet Services considered that transmission augmentation expenditure is currently driven primarily by new renewable projects.[113]

Investment incentives and clarity

AusNet Services, Meridian and Stanwell noted that the rules should support investment in storage, as it provides dispatchable generation and network support services.[114]

CleanCo and Tesla suggested that not exempting storage may impede the commercial viability of storage projects.[115] Snowy Hydro did not support the draft rule as "storage assets would be liable for TUOS, subject to their ability to negotiate TUOS charges under a negotiated service."[116] AEMO noted that an exemption from TUOS "would provide certainty for TNSP planners to contract with every IRU".[117]

The Commission notes that the default position is not that storage must pay TUOS, but that storage participants must go through the process of obtaining a shared transmission service. In doing so, storage participants can choose whether to seek a negotiated or prescribed shared transmission service. The final rule does not change the existing arrangements in which storage participants can obtain a negotiated service, and existing storage participants have been able to negotiate low or no network charges under this framework. Incentivising the uptake of particular technologies or the provision of particular services is best determined by governments as an overlay to a technology-neutral framework the Commission is seeking to provide in the rules.

112 MEU, p. 3.

113 AusNet Services, Transmission-Connected Storage and TUOS slides, October 2021.

114 AusNet Services, Transmission-Connected Storage and TUOS slides, October 2021; Meridian, p. 1; Stanwell, p. 3.

115 Submissions from CleanCo, pp. 4-6; Tesla p. 4.

116 Snowy Hydro submission, p. 1.

117 AEMO submission, p. 19.

Tesla suggested that if the AEMC's "end goal is to create a framework of cost reflective tariffs under a two-way trading participant model, it would be better for the AEMC to provide certainty" in the interim by exempting storage from paying TUOS and DUOS.[118] The Commission notes that exempting storage would not promote the NEO as explained above and the issue of how network costs should be recovered from storage and other participants are broader than this rule change and should be addressed in a specific rule change, which the Commission will prioritise.

AEMO and AusNet considered that the risk associated with uncertain shared transmission service charges needs to be priced by storage providers, and will flow through to higher costs for consumers.[119] The Commission notes that the intent of the final decision is that:

- there would be no change to existing connection agreements, including existing network charging arrangements, for storage participants, some of which do no pay network charges
- new transmission–connected storage participants can negotiate arrangements with TNSPs in the same way existing storage participants have. The Commission expects that TNSPs will negotiate price and service levels that are consistent with those that have been negotiated for existing storage participants.

The status quo maintains a level playing field

The Commission considers that the status quo approach maintains a level playing field. Some stakeholders suggested that storage should be exempt from network charges as they are competing to supply services with generators that do not pay network charges. However:

- when exporting energy, storage is treated in the same way as other generators and does not pay TUOS
- when importing energy, the current framework allows the storage proponent to negotiate the level of service it wishes to receive and the commensurate charge, which can be zero.

AusNet Services suggested that a level playing field was not necessary as there are different drivers and benefits of storage at the transmission and distribution level.[120] The Commission intends there to be a level playing field in terms of incentives to invest in storage at the transmission and distribution levels.

Appropriately allocating risks related to shared network costs

AEC, EnergyAustralia, Neoen and Snowy Hydro considered that network charges should be allocated downstream to end use consumers and not to storage, which are consuming energy for later discharge.[121] However the AEC "also recognised that there will be complexities with hybrid facilities and that a blanket rules based exemption, while beneficial for investor confidence in upstream storage, may unintentionally create avoidance

118 Tesla submission, p. 4.

119 AEMO submission, p. 19; AusNet Services, Transmission-Connected Storage and TUOS slides, October 2021

120 AusNet Services, Transmission-Connected Storage and TUOS slides, October 2021

121 Submissions from AEC, pp. 1-3, EnergyAustralia, p. 1; Neoen, p. 2; and Snowy Hydro, p. 2.

opportunities".[122] Therefore, the AEC suggested "incorporating within the rules clear principles about the intent of TUOS charging".[123]

The Commission decided to keep the current framework for the reasons explained above, and did not add principles around network charges. Such new principles could be considered in a separate rule change, which the Commission considers a priority in the near future, as explained further in appendix C.2.4.

Auxiliary loads

Snowy Hydro considered that "as the new rules would effectively no longer recognise the concept of auxiliary supply for pumped storage, pumped hydro assets will bear an unfair allocation of the costs of the transmission system, harming competition".[124]

The Commission notes, in addition to defining auxiliary load to exclude load used to charge storage, that the final rule clarifies that all existing pumped hydro providers will be moved to the IRP category. New integrated resource providers will need to go through the process of obtaining a negotiated or prescribed shared transmission service, consistent with all other types of storage and other transmission customers. However, moving existing participants to the new participant category is not intended to require them to renegotiate existing connection agreements; existing arrangements (which may provide for zero charges) could continue, subject to their own terms.

Alternative options

Shell Energy suggested the introduction of an interruptible transmission shared service for storage and other scheduled loads that are flexible and connected to the transmission network.[125] This could be defined with a lower network performance standard and lower network charges, compared to a prescribed transmission service, to reflect that it is a non-firm service that "is willing to be constrained off during times of peak network utilisation or localised network congestion".[126] The Commission notes that the introduction of an interruptible shared transmission service in the NER would require further consideration of a range of issues, including potential implications for transmission network planning, cost allocation, pricing principles and compliance.

The Commission notes that there are likely to be other alternative approaches to network charging that should be considered. This may include alternative approaches for distribution network charging, as explained in appendix C.3.4.

C.2.3 The final rule retains the current arrangements and makes amendments to improve the negotiating process

The final rule retains the current arrangements and makes amendments to:

122 That is, the potential to try to avoid network charges. AEC submission, p. 3.

123 AEC submission, p. 3.

124 Snowy Hydro submission, p. 2.

125 Shell Energy submission, p. 4.

126 Ibid, p. 4.

- specify that the new IPR market participant category is a Transmission Customer for the purposes of NER Chapters 5 and 6A in relation to electricity taken from the grid, and so will need to go through the process of obtaining a negotiated or prescribed transmission service[127]
- reduce barriers to the uptake of shared transmission services on a negotiated basis.[128]

Summary of stakeholder feedback on the draft determination

Storage participants were concerned that, through the negotiation process, a flexible schedule load such as storage, "bears the risk that

- the TNSP may set a price that is higher than what is cost reflective
- the TNSP may impose unreasonably onerous non-price conditions
- the TNSP may offer different pricing to different proponents seeking the same type of negotiated service, which would disadvantage the proponent compared to its competitors."[129]

Network businesses and the SA Government supported the flexibility of the current arrangements:

- AusNet Services, Endeavour Energy and TasNetworks supported the flexibility to negotiate agreements with batteries and other hybrid facilities.[130]
- The SA Government supported the ability for storage to receive a different service level than a prescribed transmission service, where "negotiated charges may be applicable and no TUOS is being charged".[131]
- AusNet Services noted "that TNSPs can agree to waive TUOS if they are operating as scheduled or semi-scheduled loads or operated to the net benefit of consumers".[132]
- AusNet Services noted that storage can be controllable and operated in a way to guarantee that it will not draw load during times of peak demand.[133]

The final rule retains flexibility for storage participants to choose between a negotiated or prescribed shared transmission service

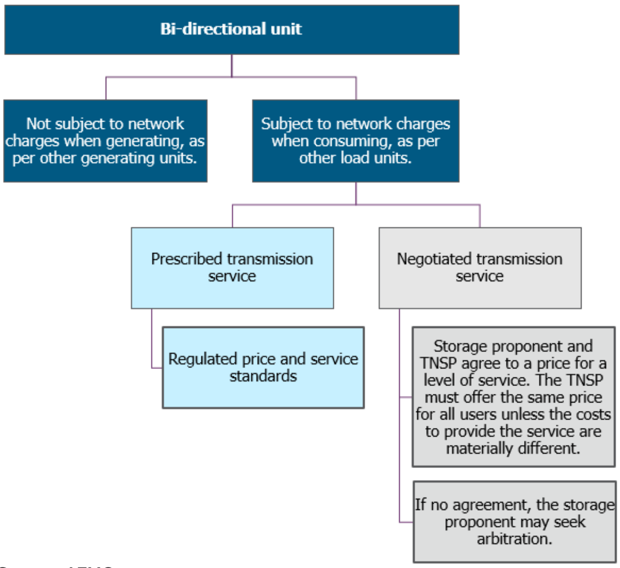
Figure C.1 outlines whether network use of system charges may apply to different types of participants under the final rule, and the process for obtaining a shared transmission network service. A storage provider seeking to connect to the transmission network has the following options for obtaining a shared transmission service, a:

- **prescribed transmission service** that has a regulated price and service standards

127 The final rule is as per the draft rule.
128 This is an additional amendment made between the draft and final rule.
129 Shell Energy, p. 3.
130 AusNet, p. 1; Endeavour Energy, p. 2.;TasNetworks, p.1.
131 SA Government, p. 3.
132 AusNet Services, p. 1.
133 AusNet Services, Transmission-Connected Storage and TUOS slides, October 2021.

- **negotiated transmission service** for a price and level of service that is negotiated with the TNSP. If the storage applicant and TNSP cannot reach an agreement, the storage provider may seek arbitration.

Figure C.1: Network charges for bi-directional units connected to the transmission network



Source: AEMC

Where a shared transmission service is provided as a negotiated transmission service, the TNSP may charge for the service. The amount of the charge is governed by existing principles in the NER, including:

- the difference between the price for a negotiated service, that does not meet or exceed the network performance requirements in schedules 5.1a and 5.1, and the price for a prescribed transmission service which meets these network performance requirements, should reflect the TNSP's avoided costs of providing the latter service[134]
- the price for the negotiated service must be the same for all transmission customers (including storage participants), unless there is a material difference in the cost of providing the service[135]
- the price may be reduced over time, if a portion of the costs of the relevant TNSP assets starts to be recovered from other participants.[136]

The final rule retains the current arrangements where a storage provider may seek a negotiated or prescribed transmission service. However, the final rule does not include the clause in the draft rule which stated that a shared transmission service may be classified as a prescribed or negotiated transmission service by reference to the network performance requirements in a connection agreement. The Commission now considers that draft clause

134 NER Schedule 5.11(4).
135 NER Schedule 5.11(5).
136 NER Schedule 5.11(6).

(cl. 5.2A.3(b1)) was unnecessary and could cause confusion, as prescribed transmission service and negotiated transmission service are defined terms in the NER.

The final rule improves investor clarity related to the negotiation process

While the process for negotiating a shared transmission service is clear in the NER, it does not appear to be straightforward in practice. The following issues were identified with the process to negotiate shared transmission services:

- CleanCo suggested that there was "uncertainty and transaction costs involved in negotiating an outcome with a TNSP"[137]
- Snowy Hydro suggested that "the unequal bargaining position is complicated by NSP's own storage investments"[138]

The Commission has made an amendment to reduce barriers to the uptake of negotiated shared transmission services. For example where a jurisdictional regulator must approve a different service performance standard for a negotiated transmission service, compared to the standard for a prescribed transmission service. The final rule requires that, where a connection applicant seeks a shared transmission service and jurisdictional legislation is, or may be, an impediment to the provision a negotiated transmission service, the TNSP must, where requested, provide:

1. information to the connection applicant about the nature of the issue and how it may be addressed; and
2. reasonable assistance with any governmental or regulatory approvals or coordination with the jurisdictional planning body required to address the issue.[139]

The Commission also notes that:

- the AER intends to re-commence its review of transmission ring-fencing guidelines in 2022. For more information, refer to appendix C.2.4.
- a further rule change, which the Commission will prioritise, which refined prescribed TUOS for large flexible loads would ideally reduce the need for storage to go through the negotiating process and therefore reduce uncertainty and transaction costs.

The final rule does not change existing negotiated agreements

The final rule is not intended to require parties to reopen existing negotiated agreements for shared transmission services. All storage providers currently connected to the transmission network have a negotiated agreement with the relevant TNSP, some of which provide for network charges of zero, and the final rule will not change this. While existing storage operators will be moved to the integrated resource provider category, this would not impact existing network charging arrangements between the storage provider and TNSP.

137 CleanCo submission, p. 6.

138 Snowy Hydro submission, p. 2.

139 Clause 5.2A.6(2A).

The ENA and CleanCo considered that this rule change should not affect existing shared services arrangements.[140]

New negotiated agreements should be consistent with existing negotiated agreements for storage participants

The Commission expects that, in accordance with schedule 5.11(5) of the NER, TNSP's and storage participants will negotiate prices for new shared transmission agreements that are consistent with existing negotiated agreements.

C.2.4 Other reform processes that may support the final rule by improving signals for efficient investment and use of the network

The Commission considers that further work is required on how network costs are recovered from storage and other market participants, as the energy market transitions to more storage and to a more dynamic pricing environment. This includes determining the most efficient approach that sends the right price signals to storage to locate in the right areas and reward storage for doing so. As noted above in appendix C.2.2, this rule change is not the appropriate avenue to address these issues.

This section outlines other reform processes that may support or work alongside the final rule, including:

- the ESB's recommendation to develop a CMM-REZ
- changes to the transmission ring-fencing arrangements.

The ESB's post-2025 recommendation to develop a CMM-REZ

On 26 August 2021, the ESB published its final advice to Energy Ministers on the post-2025 redesign of the NEM. As part of the transmission and access reform pathway, the ESB recommended a CMM. The CMM would complement the interim REZ framework and address the emerging congestion management needs of the system. A CMM-REZ is intended to:

- promote efficient investment by improving market signals for new generators and storage participants to locate in REZs[141]
- promote efficient operation and use of the network by providing better operational incentives for storage to be paid to alleviate transmission congestion[142]
- reduce uncertainty for investors.[143]

In October 2021, the National Cabinet endorsed the development of a CMM. The ESB proposed a CMM with both charges and rebates for generators.[144]

The AER's upcoming transmission ring-fencing review

The purpose of ring-fencing is to prevent regulated businesses from:

140 CleanCo, p. 1.

141 Energy Security Board, Post-2025 Market design final advice, Part a, 27 July 2021, p. 46.

142 Ibid, p. 46.

143 Ibid, p. 46.

144 For more information, please refer to: ESB, Post-2025 Market Design, Transmission and access reform pathway, October 2021.

- discriminating in favour of their related parties to disadvantage competitors operating in contestable markets; and
- not use revenue earned from regulated services to cross-subsidise contestable services.[145]

AEMO's concerns about inefficient storage location decisions, for example where a storage provider chooses to locate in a jurisdiction where network charges are favourable, are more likely to occur where ring-fencing is ineffective, rather than how network charges are applied.

The Commission notes that the AER considers that the current transmission ring-fencing guidelines, which were last updated in 2005, do not adequately address the risk of cross-subsidisation between prescribed transmission services and other services provided by the TNSP or an affiliate.[146]

The AER intends to re-commence its review of transmission ring-fencing guidelines in 2022. The Commission supports this review and notes that it is timely in the context of this final rule taking effect on XXX.

Additional information and analysis on ring-fencing is set out in the Commission's draft determination.[147]

C.3 The Commission's analysis and final decision on distribution network use of system charges

This section provides:

- a summary of the final rule that retains the current arrangements relating to distribution charges with a minor amendment
- a summary of stakeholder feedback on this aspect of the draft rule
- the Commission's analysis on distribution charges under the final rule.

Information on the draft determination can be found here, see appendix D, section D.6.

C.3.1 The final rule retains the current arrangements, with a minor amendment

The final rule retains the current arrangements where the AER classifies services and approves the DNSP's tariff classes and levels in accordance with the pricing principles.[148]

The final rule includes a minor amendment to make clear that, in the event of a dispute, the tariffs that a DNSP charges for the provision of common distribution services for customers that are not retail customers should reflect the efficient costs of providing those services to the customer.[149] The final rule reflects the draft rule.

C.3.2 Summary of stakeholder feedback on the draft rule

Key stakeholder feedback on the draft rule was:

145 AER, Ring-fencing, website viewed 28 October 2021, https://www.aer.gov.au/networks-pipelines/ring-fencing

146 AER, Electricity Transmission Ring-fencing - a review of current arrangements, Discussion paper, November 2019, p. 22.

147 AEMC, Integrating Energy Storage into the NEM, Draft determination, 15 July 2021, pp. 113-114.

148 For more information refer to AEMC, Integrating Energy Storage into the NEM, Draft determination, 15 July 2021, pp. 101-114.

149 For more information refer to AEMC, Integrating Energy Storage into the NEM, Draft determination, 15 July 2021, pp. 111.

- Distribution charges should be more cost reflective and it is inefficient to solely rely on the dispute resolution process to apply cost-reflective pricing principles[150]
- Terrain Solar suggested that, for consistency and transparency, DNSPs and TNSPs should be required to publish negotiated charges for individual projects.[151]
- The AER, Endeavour Energy and TasNetworks supported the draft decision to not exempt storage from transmission or distribution network charges.[152]
- AusNet Services suggested that a level playing field between incentives to invest in storage at the transmission and distribution levels is not necessary, given different drivers and benefits of storage at these levels.[153]
- TasNetworks noted that the inability to charge use of system would be inconsistent with the recent Access, Pricing and Incentive Arrangements for Distributed Energy Resources rule change that introduced the optionality for a DNSP to charge for export services[154]
- The AER noted that the proposal to exempt storage from TUOS "could lead energy storage proponents to invest at the transmission network, even if investment at the distribution network would be more efficient."[155] CitiPower, Powercor and United Energy had similar views.[156]

C.3.3 The final decision reflects the draft decision

The final decision retains consistency between distribution and transmission network charges

The final rule retains consistency in that storage is not exempt from paying network use of system charges, for load, whether it is connected to the transmission or distribution network. The Commission notes that the *Access, pricing and incentive arrangements for distributed energy resources* final rule removes the prohibition on DNSPs charging for export services, which means distribution level generators and small and grid-scale storage may eventually face cost reflective DUOS export charges which could also include DNSPs making payments to providers of energy import or export services.

The final decision does not change network charging arrangements for existing storage

The final decision provides greater focus on the need for network use of system charges to reflect the efficient cost to serve distribution customers that are not retail customers.

150 Terrain Solar submission, p. 2 and 3; Shell Energy Submissions, p.7..
151 Terrain Solar, p. 3.
152 AER, p. 1; AusNet Services, p. 1; Endeavour Energy, p. 1 Tas Networks, p. 2.
153 AusNet Services, Transmission-Connected Storage and TUOS slides, October 2021
154 TasNetworks, p. 2.
155 AER submission, p. 2.
156 CitiPower, Powercor and United Energy, p. 2

C.3.4 Other reform processes may support the final rule by improving signals for efficient investment in and use of the network

The Commission notes that Terrain Solar and Shell Energy suggested alternative approaches to distribution charges, such as developing additional more cost reflective service classes for storage and other participants.

As outlined in appendix C.2.4, the Commission considers that further work is required on how network costs are recovered from storage and other market participants. The Commission anticipates a rule change request to consider network charging issues for storage and other participants in more depth, which could include network charging arrangements at both the transmission and distribution network levels.

D OTHER ISSUES

This appendix considers stakeholder feedback and outlines the Commission's final decision on the remaining issues raised in this rule change. All of these final decisions have retained the draft decision and for most, stakeholders provided minimal feedback on the draft determination. Table D.1 below lists each issue and provides a summary of the Commission's final decision with more detail in the following sections.

Table D.1: Summary of the Commission's final decisions for other issues

ISSUE	COMMISSION'S FINAL DECISION
Retailer Reliability Obligation	The final rule makes IRPs liable entities under the RRO in respect of their load if aggregate annual load exceeds 10GWh in a particular NEM region. This is consistent with how Market Customers are treated.
Ancillary service provisions in Chapter 2 of the NER	The final rule defines a new umbrella term for the provision of ancillary services to replace the separate clauses which relate to ancillary service generating units and ancillary service loads. The required changes to the definition of load have been made to achieve this. Additional changes have also been made to properly integrate the IRP in these provisions, including small resource aggregators (currently MSGAs). Transitional provisions enable MSGAs to provide ancillary services from their small generating units from March 2023.
Technology specific drafting in the rules	The final rule implements AEMO's proposal to change all mentions of 'offer' to 'bid' in Chapter 3 of the NER and to make generic references to scheduled plants and registered market participants throughout the rules where possible. It makes a more preferable rule to address the ambiguity of the terms 'load' and 'generation' as they apply throughout the NER.
Other integration issues	The final rule makes a more preferable rule to address the majority of the other integration issues identified by AEMO.
Intervention compensation frameworks	Other recent rule changes have focused on intervention compensation provisions. The final rule integrates IRPs into these revised frameworks, for example by including the generation and load of bidirectional units into the compensation provisions for Affected Participants and Market Customers in rule 3.12.
Network losses and MLFs	The final rule makes no changes to the way network losses and MLFs are calculated for bi-directional connection points.
Reliability Panel representation	The final decision does not amend the Reliability Panel representation provisions to require storage and hybrid representation.
Network	The final decision will not create a unique connection pathway for NSP

ISSUE	COMMISSION'S FINAL DECISION
service provider connection points	owned energy storage systems. Therefore, the current arrangements will remain whereby an NSP owned battery must make use of a separate operator for contestable market services to file a connection agreement.

D.1 Retailer Reliability Obligation

D.1.1 Overview

The RRO is designed to encourage Market Customers to contract and invest in dispatchable capacity and demand response to support the reliability of the power system.[157] A Market Customer is considered a liable entity under the RRO if its aggregate annual load is over 10 GWh in a particular NEM region.[158]

In its rule change request, AEMO raised the issue of whether storage and hybrids should be liable entities under the RRO in respect of their loads. The Commission sought feedback on this issue in the consultation paper, asking if stakeholders thought it was appropriate for operators of these facilities to be liable entities under the RRO.

The Commission's final decision retains the draft decision, that is for IRPs to be treated the same as other participants with load (i.e. Market Customers), that is, considered liable entities under the RRO if their aggregate annual load exceeds the 10 GWh threshold.

D.1.2 Stakeholder feedback to the draft determination

Six stakeholders did not support the draft decision for storage participants to be liable entities under the RRO. These stakeholders considered:

- It may have the unintended consequence of disincentivising or preventing storage from providing load ancillary system security services during reliability events.[159]
- This draft decision is inconsistent as it carves out most existing storage except for Neoen's assets, the Hornsdale Power Reserve and Victorian Big Battery. Neoen stated the rule should apply equally to everyone or no one at all.[160]
- It would be counterproductive to require storage generation, required to firm supply of clean energy generation, to contract with ageing thermal plant to meet RRO liabilities.[161]
- Storage is an intermediary in the system and should not be treated as final consumption.[162]

Both the South Australian Department for Energy and Mining and Stanwell supported the draft decision for storage participants to be liable entities under the RRO, noting:

157 COAG Energy Council Energy Security Board, *Retailer Reliability Obligation Final Rules Package*. Available here.

158 See Part D in Chapter 4A of the NER.

159 Submissions to the draft determination: AGL, p.2; Fluence, p. 11; Shell, pp. 11-12.

160 Neoen, submission to the draft determination, pp. 5-6.

161 Submissions to the draft determination: CEC, p. 2; Merdian Energy, p. 2.

162 Submissions to the draft determination: BayWa, pp. 2-3; Neoen, p.2.

- participants with significant amounts of load at their connection point should be subject to the same requirements under the RRO[163]
- this avoids perverse incentives to register in one category rather than another and is unlikely to materially affect the way these facilities participate in the market during a reliability event.[164]

D.1.3 The Commission's final decision

The Commission's final decision retains the draft decision, which amends chapter 4A of the NER to include an IRP as a liable entity under the RRO if its load exceeds 10GWh in a particular NEM region in a year.

The Commission notes the scope of this issue was to integrate storage into the existing RRO framework, not to redesign the RRO framework and intent. Therefore, storage and hybrid facilities should not be exempt as being liable entities under the RRO, because:

- it is inappropriate to introduce technology-specific exemptions; obligations under the NER should be based on the services provided rather than an entity's technology or its participant category
- the annual consumption threshold was designed to exclude small batteries, and with the introduction of the IRP category (covering a battery's generation and load), this threshold will operate as it was originally intended.

Benefits of the final rule

The final decision ensures there will be consistent treatment of load, in respect of RRO liability, across participant types, avoiding any inefficient incentives that may arise if the load of certain participant types was exempted.

Storage can still provide load ancillary services during reliability events

The Commission notes stakeholder concern that storage may be discouraged from providing load ancillary services during RRO-triggered reliability events, but considers:

- it is more efficient to let the market provide the incentives, rather than exempting technology types
- the market price for ancillary services should accurately reflect the value of that service at the time
- if the ancillary service is valuable to the market, the price will be high, and the storage operator can decide whether to provide it and hedge, provide it and take the risk of not hedging, or not provide it.

The final decision maintains the intent of the RRO and treats storage and non-storage load consistently

The Commission considers that the new IRP participant category, in which existing and new grid-scale storage participants would be required to register, should be treated consistently

163 Stanwelll, submission to the draft determination, pp. 1-2.

164 South Australian Dept. Energy and Mining, submission to the draft determination, p. 2.

with how Market Customer load is treated, for the purpose of liability under the RRO. This would mean that an IRP's aggregate load, like a Market Customer's, would be calculated with reference to its generation as well as its load.

The Commission notes this is a change from the existing treatment where storage, being registered in two different categories, has its liability under the RRO assessed on gross load. The Commission does not agree with Neoen's position that this change targets some participants and not others,.n. The final decision provides a consistent approach for all load, regardless of which category it registers in.

The RRO is not designed to reward or punish technology or fuel source types

In response to the CEC's concern, the Commission notes the objective of the RRO is to ensure system reliability is achieved, not which technology and fuel sources are used to provide that reliability.

Further background and analysis behind this final decision can be found in the draft determination here, see Appendix E, section E.2.

D.2 Ancillary service provisions in Chapter 2 of the NER

D.2.1 Overview

The Commission's final decision retains the draft decision, which is to make a rule which streamlines the ancillary services provisions in Chapter 2 of the NER, similar to the approach that AEMO outlined in its submission to the consultation paper.

In its submission to the consultation paper, AEMO proposed revised drafting for ancillary services provisions in Chapter 2 of the NER as an improvement to its original rule change request. AEMO proposed a simpler drafting approach that is more in line with the trader-services model being developed as part of the ESB's post-2025 work. Given this was a new issue relating to the rule change request, the Commission sought feedback on this in the options paper.

D.2.2 Stakeholder feedback to the draft determination

The four stakeholders who commented on this issue supported the draft decision to create a new umbrella term for the provision of ancillary services to replace the separate clauses which relate to ancillary service generating units and ancillary service loads. These stakeholders all considered this change would create greater flexibility, improve competition in the provision of ancillary services, and facilitate innovation.[165]

Both Enel X and Tesla considered the implementation of this change should be prioritised given the benefits it would have.[166]

165 Submissions to the draft determination: South Australian Dept. Energy and Mining, p. 2; Stanwell, p. 2; Tesla, p. 14; Enel X, p. 3.

166 Submissions to the draft determination: Tesla, p. 14; Enel X, p. 3.

D.2.3 The Commission's final decision

The final decision retains the draft decision, which defines a new umbrella term for the provision of ancillary services to replace the separate clauses which relate to ancillary service generating units and ancillary service loads. The required changes to the definition of load have been made to achieve this. Additional changes have also been made to properly integrate the IRP (including small resource aggregators) in the ancillary service provisions.

The Commission notes that this drafting change will be implemented along with the majority of the rule in June 2024. However, to bring forward a key benefit of the revised provisions, the Commission has made a transitional rule which will allow market small generation aggregators to classify their small generating units as ancillary service generating units, and use them to provide ancillary services, from 31 March 2023. These units will automatically become ancillary service units under the new framework from June 2024.[167]

Benefit of the final rule

The final rule:

- is consistent with the policy objectives of the ESB's two-sided market work stream by aligning the rules with the trader-services model reform agenda
- accommodates the reality that an increasing number of connection points (controlled by participants of various types) have two-way flow and may be able to provide ancillary services both by varying import and export quantities, not just one or the other
- reduces administrative burden by making the rules less complex by minimising the number of clauses that currently relate to the provision of ancillary services for each type of asset, and removing unnecessary distinctions between ancillary services provided by varying import quantities and those provided by varying export quantities
- increases competition in the provision of ancillary services as soon as practicable, by allowing market small generation aggregators to provide those services, as a transitional provision before AEMO is able to implement the other ancillary service changes.

Further background and analysis behind this final decision can be found in the draft determination here, see Appendix H.

D.3 Technology specific drafting in the rules

D.3.1 Overview

The final decision retains the draft decision, which implements AEMO's proposals to change all mentions of 'offer' to 'bid' throughout the NER, and to make generic references to scheduled plants and registered market participants throughout the NER where practicable. It makes a more preferable rule to address the ambiguity of the terms 'load' and 'generation' as used in different contexts throughout the NER. Some additional streamlining of drafting has been done between the draft and final rules.

167 Final rule, new clause 11.142.19.

In its rule change request, AEMO identified that the NER currently contain technology specific language which does not recognise bi-directional flows at a connection point. AEMO considered this impedes the effective integration of storage and hybrids into the NEM. This issue is separate from the decision on having a definition of storage in the NER. Instead, it focuses on amending existing terms and definitions in the NER to make them more consistent with the way the market is evolving.

D.3.2 Stakeholder feedback to the draft determination

Only one stakeholder provided feedback on this draft decision. The South Australian Department of Energy and Mining supported the draft changes to address the ambiguity of the terms 'load' and 'generation' as they apply throughout the NER.[168]

D.3.3 The Commission's final decision

The final decision retains the draft decision, which is to makes a more preferable rule for addressing technology specific drafting. It directly incorporates two of the solutions proposed by AEMO for addressing this issue:

- replacing all mentions of 'offer' with 'bid' in the NER
- making generic references to scheduled plants and market participants where practicable.

The final rule also considers the use of the terms generation and load throughout the NER, and replaces them with clearer, more accurate terms where necessary (noting that these terms include the activities of storage technologies in producing and consuming electricity; there is no separate definition of 'storage' as an activity or service). This has been done to address the concerns AEMO raised about existing terms being based on an assumption of one-way electricity flows in the NER, which does not reflect the current reality of the NEM.

Benefits of the final rule

The final rule will reduce regulatory burden in the longer term and make the NER more future-proof by:

- improving the drafting of the rules by reducing the extent of technology specific language in them
- addressing the ambiguity of how certain terms and concepts apply to energy storage and hybrids
- better reflecting the fact that a large and increasing number of connection points in the NEM have two-way flow
- updating the NER to provide a more suitable basis for future reforms under the ESB's P2025 program.

Further background and analysis behind this final decision can be found in the draft determination [here](), see Appendix E, section E.1.

168 South Australian Dept. Energy and Mining, submission to the draft determination, p. 2.

D.4 Other integration issues

D.4.1 Overview

The Commission's final decision retains the draft decision, which is to address the majority of these drafting issues identified by AEMO. Other minor drafting issues identified by AEMO will be addressed, or have been addressed, in minor rule changes initiated by the Commission.

When writing its detailed drafting proposal for Chapters 2, 3 and 10 of the rules, AEMO also identified a collection of additional issues in the existing drafting of the NER that do not directly relate to the integration of storage and hybrid facilities. AEMO suggested the Commission consider these in the rule change process.[169] However, these issues do not explicitly relate to achieving the core objectives of the rule change.

There has been minimal stakeholder feedback on this issue, with only one stakeholder commenting and supporting the draft decision.

D.4.2 Stakeholder feedback to the draft determination

Only one stakeholder provided feedback to the draft decision. Stanwell supported streamlining the NER by fixing drafting errors and improving clarity of the provisions being amended as part of the rule change, improving the overall coherence of the NER.[170]

D.4.3 The Commission's final decision

The Commission's final decision retains the draft decision, which is to make a more preferable rule that addresses the majority of the other drafting issues identified by AEMO. Table D.2 outlines the issues and the Commission's analysis.

Although these issues do not directly relate to the integration of storage and hybrids into the NEM, the Commission considers it appropriate to address a number of these issues, where they are minor corrections to errors in the NER. The Commission is comfortable addressing these issues as part of this rule change as they will improve the drafting of the rules by making them more coherent. Where the issues are more material, the Commission has carefully considered whether they are best dealt within this rule change or otherwise.

Further background and analysis behind this final decision can be found in the draft determination here, see Appendix E, section E.6.

Table D.2: **Commission response to other drafting issues in the NER identified by AEMO**

CLAUSE	ISSUE RAISED BY AEMO	COMMISSION'S ANALYSIS
2.2.1(c) and (d)	Note in paragraph (c) is incomplete and therefore inaccurate. Paragraph (d) only identifies that AEMO can	In relation to (c), the note has been removed as the provision has been redrafted. In relation to (d), now moved to clause 2.1A.2(b), the

169 AEMO, *Integrating energy storage systems into the NER — rule change request, p. 24*

170 Stanwell, submission to the draft determination, p. 2.

CLAUSE	ISSUE RAISED BY AEMO	COMMISSION'S ANALYSIS
	exempt a person or class of persons from the requirement to register as a Generator for only a generating system or class of generating systems. This should also include generating units.	Commission has determined not to make this change given the wording of the relevant registration and exemption provisions in the NEL.
2.2.6(b), (e)(2), 2.3.5(b)(1)(e)(1A), (2)	Where occurring, the references should be to an 'applicant' since the person is not yet a registered participant.	These provisions have been redrafted.
2.2.6(d), 2.3.5(d), 2.9.1(c) and 2.9A.2(d)	These clauses require AEMO to deem an application as withdrawn if AEMO has not received all the necessary information or clarifications within 15 business days of AEMO requesting the information. It is more appropriate to allow AEMO the discretion to withdraw an application instead.	The Commission agrees with AEMO's suggestion to give it discretion to treat an application as withdrawn if an applicant does not provide information or clarification required by AEMO within 15 business days of a request by AEMO. If AEMO exercises the discretion then it must notify the applicant. This approach is more flexible compared to the current provision that deems the application to have been withdrawn. Changes made in the final rule.
3.6.3(c) and (d)(1)	References to 'predominant load flows' is incorrect. These flows refer to NER clauses 3.6.3(b)(2)(A) and (B), which refers to consumed and sent out electricity. Delete reference to 'load'.	The Commission's final determination is not to make these changes in light of subsequent advice from AEMO that the meaning of "load flow" is understood and appropriate in this context.
3.6.5(a)(4) and (4A)	"then" is duplicated.	The final rule makes this correction.
3.7C, 3.8.10, 3.9.3D	Consistent with other provisions, new paragraphs are proposed to be included to allow AEMO to make minor and administrative changes to the Constraint Formulation Guidelines, EAAP Guidelines	The Commission does not consider it appropriate to address this issue in this rule change, as it will be addressed more comprehensively in the Improving consultation procedures in the Rules rule change.

CLAUSE	ISSUE RAISED BY AEMO	COMMISSION'S ANALYSIS
	and reliability standard implementation guidelines without undertaking a Rules consultation.	
3.8.4(c)(3)	Should refer to 'energy constrained scheduled generating units'.	The final rule makes this correction.
3.8.5(b)	Repetitive and extraneous information. Requirement for off-loading prices in the generation dispatch offer is also incorrect, this information is not required.	The final rule adopts the simplified drafting provided.
3.8.6(c), (h)(3)(ii), (f), (h)(1)and (2), 3.12.2(2)	Duplicated use of terms — delete either 'multiplied by' or 'product of'.	The final rule makes these corrections.
3.8.7(m)	The reference to 'may' is incorrect. Other references in the clause refer to 'must'. Where a scheduled generating unit has an energy constraint it must indicate its daily energy availability.	The Commission considers AEMO's proposed change appropriate, and the final rule makes this correction. Additionally, the Commission has also amended clause 3.8.6(b) to the same effect.
3.8.17(c), 3.8.18(a)	Should refer to Scheduled Generator, not Generator.	The final rule makes these corrections.
3.8.18(e)	Reference to 'Market Participant' is incorrect, the obligation is only on Scheduled Generators.	The final rule makes this correction.
3.8.21(d)	Dispatch instructions are not always issued using automatic generation control (AGC) system and not via an electronic display in the plant control room. For future proofing, the drafting should only refer to electronic communication.	The Commission agrees with AEMO's issue with the current drafting and recognises that the proposed re-drafting helps to future proof the rules. The final rule makes the proposed change.
3.13.3(a)(3)	Refers to 'Scheduled Generators' and Semi-Scheduled Generators', this is	The final rule makes this correction.

CLAUSE	ISSUE RAISED BY AEMO	COMMISSION'S ANALYSIS
	an error since only Market Participants can be suspended.	
3.13.3(l2)	This clause misinterprets the requirements in S5.2.4, which currently only applies to 30MW+generating systems, whether pre- or post-registration. Therefore, the requirement is not separate from a registered Generator's obligation and can be covered by slightly expanding 3.13.3(a).	The Commission agrees with AEMO that S5.2.4(b) is currently only intended to capture generators with a generating system of 30MW or more, or connection applicants who need to provide this information in respect of a generating system of 30MW or more but are not yet formally registered as a Generator. The final rule extends this clause to also cover integrated resource systems with a combined nameplate rating of 5MW or more. The Commission has amended the language in clause 3.13.3(l2) to make this clearer and to clarify that it applies to Generators, IRPs, or persons required to register in either category under the rules.
3.13.3(l2)(5)	Transmission Network Service Provider is not italicised.	The Commission is addressing this error in the minor rule change currently on foot, which will take effect in January 2022, well before the changes for this rule change will be implemented.
3.13.4(p)(5)	Inappropriate reference to "as measured by AEMO's telemetry system". The Market Participant's SCADA measures and AEMO receives via SCADA.	The final rule makes this correction.
3.15.8(f)(2), 3.15.8A(g)(2), 3.15.10C(b)(7)(i), (c)(3)(iii)(B)	Delete 'TSRP', this is not defined.	The final rule makes these corrections.
3.15.8(f)(2)	Delete 'TRSP', this is not defined.	This change has already been made. The term no longer appears in the clause as of NER v158.
3.15.21(c2)(2)(ii)	Market Ancillary Service Provider omitted from the	The final rule expands this provision to all Market Participants

CLAUSE	ISSUE RAISED BY AEMO	COMMISSION'S ANALYSIS
	clause. Under the Ancillary Services Unbundling Rule 2016 this provision was to exclude retailers (Market Customers) only. Although it is unlikely that a MASP would incur liabilities, excluding them was not the intent.	and makes a consequential change to delete the following clause, 3.15.21(c2)(2)(iii).
3.8.20(g)	Reference to scheduled generating unit and semi-scheduled generating unit omitted.	The Commission agrees with AEMO's proposal to amend this clause, which makes it clear that dispatchable plants are obliged to comply with clauses related to central dispatch. Changes made in the final rule.
3.8.20(i)	AEMO should make documentation on the operation of the pre-dispatch process available only to Market Participants.	The Commission agrees with AEMO's proposal to only make documentation available to Market Participants. Market Participants captures all registered participants which participate in central dispatch and non-market generators would not require this information. Changes made in the final rule.
3.8.20(j)(2)	This should refer to a unit instead of an entity.	The final rule makes this correction.
3.8.20(k)	'Scheduled load' omitted.	The final rule makes this correction.
7.4.1(e)	MSGA omitted from this clause.	The final rule makes this correction (using the new term Small Resource Aggregator).
dispatched load	Redundant definition, this is the same as scheduled load.	The final rule amends the definitions of both dispatched load and scheduled load, and with these changes the definitions are not the same. Both terms are retained.
peak load	Definition is circular.	The final rule retains this definition following changes to the definition of load.

Source: AEMO, *Integrating energy storage systems into the NEM — rule change request,* pp. 24-25, 46-47, and Commission analysis.

D.5 Intervention compensation frameworks

The Commission's final decision retains the draft decision, which is to not develop any unique arrangements for storage and hybrids in the intervention compensation frameworks. There was no feedback received on this issue in response to the draft determination.

In its rule change request, AEMO questioned how the intervention compensation frameworks should apply to storage and hybrid facilities. In particular, AEMO questioned how the frameworks would apply to the BDRP registered participant category it proposed. AEMO did not set out an approach for applying these frameworks to storage and hybrids because the frameworks were subject to rule change requests that were yet to be submitted at the time.

The Commission sought feedback from stakeholders in the consultation paper asking if the current frameworks can appropriately accommodate storage and hybrids, or if a unique intervention compensation framework would need to be developed for these kinds of facilities.

Further background and analysis behind this final decision can be found in the draft determination here, see Appendix E, section E.3. The *Compensation for market participants affected by intervention events* final rule determination, released alongside this final determination, also considered how the compensation framework in clause 3.12.2 (which applies to some market participants dispatched differently as a result of AEMO intervention events that trigger intervention pricing) will apply to integrated resource providers in respect of bidirectional units.[171]

The final rule includes integrated resource providers in the compensation framework in clause 3.12.2 as follows:[172]

- generation from scheduled units classified by integrated resource providers (including generating units and generation from bidirectional units) is included with the provisions for compensation of Affected Participants
- energy consumed by scheduled units classified by integrated resource providers (including scheduled load and consumption by bidirectional units) is included with the provisions for compensation of Market Customers
- ancillary services from ancillary service units classified by integrated resource providers, including small resource aggregators, is included with the provisions for compensation of ancillary service providers (inserted by the *Compensation for market participants affected by intervention events* rule change).

171 For further details on this rule change and its considerations relating to integrated resource providers, please refer to the final determination available here.

172 Final rule, amendments to clause 3.12.2.

D.6 Network losses and marginal loss factors

D.6.1 Overview

The Commission's final decision retains the draft decision, which is to apply MLFs to storage and hybrid systems consistently with the way they are currently applied to generating units and loads.

MLFs notionally describe the marginal electrical energy losses for electricity transmitted between a regional reference node and a transmission connection point in the same region for a defined time period and associated set of operating conditions.[173] MLFs are also commonly referred to as intra-regional loss factors, transmission loss factors and static loss factors.

In its rule change request, AEMO proposed how network losses and MLFs should apply to storage and hybrids. As AEMO did not propose any significant changes to how MLFs are calculated for these assets from the current arrangements, the Commission sought feedback in on whether these arrangements are appropriate.

D.6.2 Stakeholder feedback to the draft determination

Four stakeholders supported the draft decision to not make changes to the way MLFs are calculated for storage and hybrid systems.[174]

Engevity sought clarity on how MLFs will be established for IRPs, noting that currently MLFs are calculated based on an assumed or historic generation profile, which is reasonably predictable for wind and solar. It argued that, if a battery is added, the dispatch profile would change daily if the IRP is responding to market signals. Engevity understands that IRPs will have input and output MLFs applied, but suggests the AEMC should consider a different MLF for dispatch and settlement as it is counter-productive to forecast a 5-min dispatch schedule to determine an IRP's generation profile when it exists to respond to market signals.[175]

D.6.3 The Commission's final decision

The Commission's final decision retains the draft decision, which is to not make any amendments to how MLFs are applied to storage and hybrids. In response to Engevity's suggestion, the Commission notes that MLFs are already calculated separately for scheduled generators and loads (other than batteries) in the NEM. The Commission has not received any advice from AEMO or other stakeholders that adding storage to wind and solar generation could create any new issues in relation to MLFs.

D.7 Reliability Panel representation

The Commission's final decision retains the draft decision, which is to not explicitly require storage participants to be represented on the Reliability Panel. There was no feedback received on this issue in response to the draft determination.

173 Clause 3.6.2(b)(1) of the NER.

174 Submissions to the draft determination: ENA, p. 6; EnergyAustralia, p. 2; AusNet Services, p. 3; CEC, p. 2.

175 Engevity, submission to the draft determination, p. 4.

In its rule change request, AEMO asked the Commission to consider if it would be appropriate to adjust Reliability Panel representation provisions to include a requirement for storage participants to be represented on the panel.[176] The consultation paper sought feedback from stakeholders on this issue, and whether storage and hybrids should be represented more generally.

Further background and analysis behind this final decision can be found in the draft determination here, see Appendix E, section E.5.

D.8 Network service provider connection points

D.8.1 Overview

The Commission's final decision retains the draft decision, which is to not create a unique connection pathway for NSP owned energy storage systems. Therefore, a connection agreement for an NSP-owned battery in relation to contestable market services must continue to be filed by a separate third party operator.

AEMO's submission to the consultation paper identified that the NER currently do not contemplate a connection agreement process for assets where the connection applicant and the local network service provider (NSP) are the same party. This was one of the issues which AEMO became aware of after submitting the rule change request in August 2019.[177]

AEMO did not propose a solution to this issue in its submission to the consultation paper. Because of this, the Commission proposed a solution to this issue and sought stakeholder feedback. Specifically, the Commission sought feedback on whether stakeholders supported the proposed solution and if they considered there to be a more preferable means of resolving this issue.

D.8.2 Stakeholder feedback to the draft determination

Three stakeholders commented on the draft decision for this issue.

Endeavour Energy supported the draft decision, noting where network owned batteries are used to provide competitive services, networks will typically partner with appropriately registered and accredited third-party operators who will act as the connection applicant.[178]

Both Endeavour Energy and EnergyAustralia considered planned updates to the distribution and transmission ring-fencing guidelines would more clearly separate competitive and monopoly services provided from batteries and may further ensure networks do not connect their batteries on favourable terms to the detriment of third-party owned storage.[179]

Ausgrid sought clarity on how the rules will apply to smaller network-owned energy storage devices, generally smaller than 1 MWh in size. To get the full value out of these batteries,

176 AEMO, *Integrating energy storage systems into the NEM* — rule change request, p. 46.

177 AEMO, submission to the consultation paper, p. 6.

178 Endeavour Energy, submission to the consultation paper, p. 2.

179 Submissions to the draft determination: Endeavour Energy, p. 2; EnergyAustralia, p. 7.

network businesses are trialling leasing spare capacity to registered market participants for use in contestable market services.[180]

D.8.3 The Commission's final decision

The Commission's final decision retains the draft decision, which is to not create a unique connection pathway for NSP owned energy storage systems. Therefore, a connection agreement for an NSP-owned battery in relation to contestable market services must continue to be filed by a separate third party operator.

In response to Ausgrid's request for clarity, the Commission:

- notes that small batteries (less than 5 MW) are exempt from the classification and connection processes, and therefore are not required to agree and meet system performance standards, but would still require a market participant (retailer or small resource aggregator) if they are used to provide contestable market services
- understands that NEMDE is limited to 1 MW increments in relation to dispatch for FCAS and energy, so a small battery less than 1 MW that is not aggregated would not be able to participate.

180 Ausgrid, submission to the consultation paper, p. 1.

E LEGAL REQUIREMENTS UNDER THE NEL

This appendix sets out the relevant legal requirements under the NEL for the Commission to make this final rule determination.

E.1 Final rule determination

In accordance with s. 102 of the NEL the Commission has made this final rule determination in relation to the rule proposed by the Australian Energy Market Operator.

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

A copy of the more preferable final rule is attached to and published with this final rule determination. Its key features are described in appendix E.

E.2 Power to make the rule

The Commission is satisfied that the more preferable final rule falls within the subject matter about which the Commission may make rules. The more preferable final rule falls within s. 34 of the NEL as it relates to regulating the operation of the national electricity market and to regulating the activities of persons (including registered participants) participating in the national electricity market (NEL ss. 34(1)(a)(i) and (iii)).

E.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the rule
- the rule change request
- submissions received during first, second and third round consultation
- the Commission's analysis as to the ways in which the more preferable final rule will or is likely to, contribute to the NEO.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[181]

The Commission may only make a 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.[182] The more preferable final rule is compatible with AEMO's declared network functions because it would not affect those functions.

181 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.

182 Section 91(8) of the NEL.

E.4 Rule making in the Northern Territory

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:[183]

(a) the national electricity system

(b) one or more, or all, of the local electricity systems[184]

(c) all of the electricity systems referred to above.

Under the NT Act and its regulations, only certain parts of the NER have been adopted in the Northern Territory.[185]

As the more preferable final rule relates to parts of the NER that apply in the Northern Territory, the Commission has assessed whether to make a uniform or differential rule (defined below) under Northern Territory legislation.

Under the NT Act, the Commission may make a differential rule if, 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.[186] A differential rule is a rule that:

- varies in its term as between:
  - the national electricity system, 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.[187]

The Commission's determinations in relation to the meaning of the "national electricity system" and whether to make a uniform or differential rule are set out in chapter 2.

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

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

185 The version of the NER that applies in the Northern Territory is available on the AEMC website at www.aemc.gov.au/regulation/energy-rules/northern-territory-electricity-market-rules/current.

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

187 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.

E.5 Civil penalties

The Commission cannot create new civil penalty provisions. However, it may, jointly with the AER, recommend to the Energy Ministers Meeting that new or existing provisions of the NER be classified as civil penalty provisions.

The NEL sets out a three-tier penalty structure for the NEL and NER.[188] A Decision Matrix and Concepts Table,[189] approved by Energy Ministers, provides a decision-making framework that the Commission applies, in consultation with the AER, when undertaking the assessment of whether to recommend that provisions of the NER be classified as civil penalties, and if so, under which tier.

E.5.1 New provisions the Commission proposes to recommend be classified as civil penalty provisions

The Commission's more preferable final rule inserts the provisions set out in the table below into the NER (among other changes).

The Commission considers that these new provisions should be classified as civil penalty provisions for consistency with similar provisions (currently classified as civil penalty provisions) that apply to other types of registered participants, and to promote compliance with these new obligations so that they operate effectively. The Commission has consulted with the AER on these recommendations and the AER supports these decisions.

Table E.1: **New provisions in more preferable final rule proposed to be recommended as civil penalty provisions**

CLAUSE	SUBJECT OF CLAUSE	PROPOSED CLASSIFI-CATION	REASON
2.2.5A(b)	Requirement on Integrated Resource Providers (IRPs) to sell all sent out generation through the spot market and accept payments from AEMO in accordance with Chapter 3.	Tier 1	Align with existing provisions for other participant categories.
2.2.5A(c)	Requirement on IRPs to purchase all electricity supplied through the national grid to the IRP at that connection point from the spot market and make payments to AEMO in accordance with Chapter 3.	Tier 1	Align with existing provisions for other participant categories.
2.2.7(c2)	Requirement on a person who wishes to classify a semi-scheduled generating unit to comply with terms and conditions imposed by	Tier 1	Align with existing provisions for

188 Further information is available at: https://www.aemc.gov.au/regulation/energy-rules/civil-penalty-tools.

189 The Decision Matrix and Concept Table are available here.

CLAUSE	SUBJECT OF CLAUSE	PROPOSED CLASSIFI-CATION	REASON
	AEMO under clause 2.2.7(c1).		other participant categories.
2.2.8(d)	Requirement on Small Resource Aggregators (SRAs) to sell all sent out generation from their market supply points through the spot market and accept payments from AEMO in accordance with Chapter 3.	Tier 1	Align with existing provisions for other participant categories.
2.2.8(e)	Requirement on SRAs to purchase all electricity supplied through the national grid to their market connection points from the spot market and make payments to AEMO in accordance with Chapter 3.	Tier 1	Align with existing provisions for other participant categories.
2.3.4(f)	Requirement on Market Customers to purchase all electricity supplied to their connection points from the spot market and make payments to AEMO in accordance with Chapter 3.	Tier 1	Align with existing provisions for other participant categories.
2.3.4(g)	Requirement on Market Customers to sell all sent out generation from connection points they have classified as market connection points through the spot market and accept payments from AEMO in accordance with Chapter 3.	Tier 1	Align with existing provisions for other participant categories.
2.3D.2(a)	Requirement on Ancillary Service Providers (ASPs) to comply with terms and conditions imposed by AEMO under clause 2.3D.1(g).	Tier 1	Align with existing provisions for other participant categories.
2.3D.2(b)(1)	Requirement on ASPs to ensure that the market ancillary services provided are in accordance with the co-ordinated central dispatch process operated by AEMO and the market ancillary service specification.	Tier 1	Align with existing provisions for other participant categories.
2.3D.2(c)	Requirement on ASPs with an ancillary service unit to sell the market ancillary services produced using that ancillary service unit through the spot market.	Tier 1	Align with existing provisions for other participant categories.
4.9.8(a3)	A requirement on Registered Participants to	Tier 1	Align with

CLAUSE	SUBJECT OF CLAUSE	PROPOSED CLASSIFI-CATION	REASON
	ensure their scheduled resources are at all times able to comply with the latest dispatch bid under Chapter 3.		existing provisions for other participant categories.
5.2.5A(a)	Requirement on IRPs to plan and design their facilities and ensure they operate to comply with the relevant and applicable performance standards, connection agreement and system standards.	Tier 1	Align with existing provisions for other participant categories.
5.2.5A(c)	Requirement on IRPs to comply with any terms and conditions of a connection agreement for their systems that provide for the implementation, operation, maintenance or performance of a system strength remediation scheme.	Tier 1	Align with existing provisions for other participant categories.
5.2.5A(d)	Requirement on IRPs to provide information to AEMO and the relevant NSP in accordance with the Power System Model Guidelines, the Power System Design Data Sheet and the Power System Setting Data Sheet if AEMO believes there is a risk that the IRPs' plant will adversely affect the network or other users.	Tier 2	Align with existing provisions for other participant categories.
5.2.5A(e)	Requirement on IRPs to provide certain information to AEMO and the relevant NSP, if requested by AEMO, to allow the NSP to conduct the assessment required under clause 5.3.4B.	Tier 2	Align with existing provisions for other participant categories.
5.3.9(b)(2A)	Requirement that an IRP submit to the relevant NSP and AEMO, in respect of a proposed alteration to a unit, design data and setting data in accordance with the Power System Model Guidelines, Power System Design Data Sheet and Power System Setting Data Sheet.	Tier 2	Align with existing provisions for other participant categories.
5.3.10(a1)	Requirement on IRPs not to commission altered generating plant until the NSP has advised the Generator that the provider and AEMO are satisfied.	Tier 1	Align with existing provisions for other participant

CLAUSE	SUBJECT OF CLAUSE	PROPOSED CLASSIFI-CATION	REASON
			categories.
5.7.3(a1)	Requirement for IRPs to, in accordance with rule 4.15, provide evidence to any relevant NSP with which that IRP has a connection agreement and to AEMO, that its generating system or integrated resource system (as applicable) complies with the applicable technical requirements and connection agreement.	Tier 3	Align with existing provisions for other participant categories.
5.20B.6(b1)	Requirement on Inertia Service Providers to register the BDU with AEMO as an inertia unit and specify that the BDU may be periodically used to provide inertia network services and will not be eligible to set spot prices when constrained on to provide inertia.	Tier 2	Align with existing provisions for other participant categories.
5.20C.4(b1)	Requirement on System Strength Service Providers that procure system strength services from an IRP under a system strength services agreement to register the BDU with AEMO as a system strength unit and specify that the BDU may be periodically used to provide system strength services and will not be eligible to set spot prices when constrained on to provide system strength services.	Tier 2	Align with existing provisions for other participant categories.
11.145.2(c)	Requirement for Registered Participants to whom clause 11.145.2 applies to apply to AEMO under rule 2.9 to change their registration category to IRP and to reclassify their integrated resource system under the new Chapter 2.	Tier 2	To ensure that relevant Registered Participants are transferred into the IRP category.
11.145.2(d)	Requirement for Existing Non-Customer Load Participants, in respect of their scheduled loads, to apply to AEMO under new Chapter 2 to register as a Customer or an Integrated Resource Provider and take such steps necessary to classify their plant as a scheduled load.	Tier 2	To ensure that relevant Registered Participants are transferred into the IRP category.

E.5.2 Amendments to existing provisions

The Commission's more preferable final rule amends, or removes, various provisions of the NER that are currently classified as civil penalty provisions under Schedule 1 of the National Electricity (South Australia) Regulations. The Commission considers that:

- provisions that have been amended should continue to be classified as civil penalty provisions, at the same tier; and
- provisions that have been removed should not continue to be classified as civil penalty provisions.

The Commission does not propose to recommend any change to the classification of amended civil penalty provisions to the Energy Ministers Meeting, but will recommend to the Energy Ministers Meeting that provisions that have been removed should not longer be classified as civil penalty provisions.

E.6 Conduct provisions

The Commission cannot create new conduct provisions. However, it may recommend to the Energy Ministers Meeting that new or existing provisions of the NER be classified as conduct provisions.

The more preferable final rule does not amend any rules that are currently classified as conduct provisions under the NEL or National Electricity (South Australia) Regulations. The Commission does not propose to recommend to the Energy Ministers Meeting that any of the proposed amendments made by the more preferable final rule be classified as conduct provisions.

E.7 Review of operation of the rule

The more preferable final rule does not require the Commission to conduct a formal review of the operation of the rule. The Commission may however self-initiate a review of the operation of the rule at any time if it considers such a review would be appropriate, pursuant to section 45 of the NEL.

F SUMMARY OF AMENDMENTS TO THE NATIONAL ELECTRICITY RULES

This appendix outlines the amendments to the NER made under the more preferable final rule. Appendix B provides an overview of the key changes between the draft rule and the final rule.

The final rule, other than the savings and transitional provisions in rule 11.145, commences on 3 June 2024. References to the "current rules" in this appendix are references to the rules in force at the date of this determination.

F.1 Introduction to key concepts

Under the final rule, several new concepts have been introduced or existing concepts have been modified.

F.1.1 Unit categories

- The defined term *generating unit* (covering 'plant used in the production of electricity and all related equipment essential to its functioning as a single entity') becomes the new term *production unit*. The term *generating unit* is redefined as a production unit that is not a bidirectional unit.
- A new term, *bidirectional unit*, is a production unit that also consumes electricity that is not, or is in addition to, its auxiliary load. A new defined term *auxiliary load* covers electricity consumption used for the operation of a production unit but does not include electricity consumption used to create the source of energy converted by the production unit to electrical power.
- The current terms *ancillary service generating unit* and *ancillary service load* are replaced with a new umbrella term, *ancillary service unit* which encompasses generating units, bidirectional units and other connected plant classified as an ancillary service unit.
- The new term *small bidirectional unit* corresponds to the existing term *small generating unit*.
- The new terms *distribution connected bidirectional unit* corresponds to the existing term *embedded generating unit,* in turn replaced with *distribution connected generating unit.* A new collective term *distribution connected unit* means a *distribution connected generating unit* or a *distribution connected bidirectional unit.*

F.1.2 System Categories

- A *generating system* is defined as in the current NER but excludes an *integrated resource system*.
- A new defined term *integrated resource system* covers:
  - a system comprising one or more bidirectional units (and which may also comprise one or more generating units or other connected plant that is not part of a bidirectional unit); or

- a system comprising one or more generating units where the connection point for the system is used to supply electricity for consumption that is not, or is in addition to, auxiliary load (but not solely auxiliary load).

F.1.3 Registration categories

- An *Integrated Resource Provider* (IRP) is a person registered as such. The units and plant that can be classified by an IRP are described below.
- The new term *Small Resource Aggregator* replaces the Market Small Generation Aggregator registration category. A Small Resource Aggregator is an IRP that has classified the connection point for a small generating unit or a small bidirectional unit (small resource connection points) as one of its market connection points.

F.1.4 Other new or replacement terms

- References to dispatch offers are replaced with references to *dispatch bids* and references to market ancillary service offers are replaced with references to *market ancillary service bids*.
- References to bid and offer validation data are replaced with references to *bid validation data*.
- References to *market load* are removed and connection points at which electricity supplied through the national grid is purchased or sold by an end user (end user connection points) are classified as market connection points by a registered Customer or an Integrated Resource Provider.
- A new term *scheduled resource* refers to all plant subject to AEMO's central dispatch process - scheduled generating units, semi-scheduled generating units, scheduled bidirectional units, scheduled load, wholesale demand response units and scheduled network services.

F.2 Changes to Chapter 2

Chapter 2 has been amended to introduce the new IRP registration category and the classification arrangements for bidirectional units. Other changes have been made to remove redundant registration and classification categories from the rules and to rearrange chapter 2 to clarify meaning and improve readability.

F.2.1 Obligations to register or classify

The obligation to register under the NER in relation to the generation of electricity (or to be exempt) and for the purchase and sale of electricity through the spot market is derived from the NEL. The current NER in turn sets out the registration requirements in more specific terms. The amendments to chapter 2 bring these obligations together in a new rule 2.1A.

This rule covers the obligation to register in relation to generating systems, integrated resource systems, purchasing and selling electricity directly in the spot market, providing wholesale demand response and providing market ancillary services.

AEMO's power to exempt a person or class of persons from the requirement to register in relation to a generating system is extended to integrated resource systems and included as new clause 2.1A.2.

F.2.2 Market Participant registration categories for the sale or purchase of electricity

A new rule 2.1B brings together the requirements for registration as a Generator, Customer or Demand Response Service Provider and is extended to cover the requirements for registration as an IRP. The rule also includes, in modified form, the current requirements for the provision of closure year notices.

The *Generator* registration category continues to be available for a person who wishes to be the Registered Participant for a generating unit but not as an IRP.

The *Customer* registration category continues to be available for a person who wishes to be the Market Participant for electricity supplied to end users but is modified to recognise that the end users may be exporting electricity to the grid as well as importing. The Customer registration category also continues to be available for registration in relation to a scheduled load.

The *Demand Response Service Provider* registration category is open to a person that wishes to classify a connection point to provide wholesale demand response or who wishes to classify plant at a connection point as an ancillary service unit to provide market ancillary services.

The new *Integrated Resource Provider* registration category applies as follows:

- as a Market Participant category for registration as the owner, operator or controller of a generating system or an integrated resource system,
- as a Market Participant category for a person who wishes to participate in the market in relation to connection points that connect small generating units or small bidirectional units, acting as a *Small Resource Aggregator*,
- as a Market Participant category for a person who wishes to purchase or sell electricity directly in the market in relation to any other customer connection point, including a connection point that connects scheduled load, acting as a Market Customer.

Under the final rule, the terms Market Generator and Market Customer continue to be used as labels to identify Market Participants who are financially responsible for generating units or end user connection points.

New rule 2.9B allows Generators and Customers to transfer to the new Integrated Resource Provider registration category.

F.2.3 Classification of generating units and bidirectional units

The requirements for classification of generating units and bidirectional units are brought together in a revised rule 2.2.

As under the current NER, a generating unit may be classified as a scheduled generating unit, a semi-scheduled generating unit or a non-scheduled generating unit.

Under the final rule a bidirectional unit can be classified as a scheduled bidirectional unit or a non-scheduled bidirectional unit. In general:

- a scheduled bidirectional unit is a bidirectional unit with a nameplate rating for both production and consumption of 5MW or more unless AEMO has approved the classification of the bidirectional unit as a non-scheduled bidirectional unit.
- a non-scheduled bidirectional unit is a bidirectional unit with a nameplate rating for both production and consumption of less than 5MW.

There is no concept under the final rule of a semi-scheduled bidirectional unit. However, to allow flexibility for 'DC-coupled systems' (integrated resource systems comprising intermittent generation such as wind and bidirectional units where the units use a single inverter), the final rule allows these to be classified as scheduled bidirectional units, separate units with separate classification or, subject to conditions in the rules, as a semi-scheduled generating unit. These options are provided for under clause 2.2.2(a1) of the final rule, together with clauses 2.2.2(b4) and 2.2.7(c1).

Some facilities that would satisfy the definition of 'bidirectional unit' (pumped hydro) cannot move linearly from one mode of operation to the other (ie from generation to consumption or vice versa). The final rule requires these units to be classified as a scheduled generating unit and a scheduled load. This is provided for in clauses 2.2.2(a1)(2) of the final rule, together with clauses 2.2.2(b2) and 2.3.4A.

Under the final rule, Generators may only classify scheduled generating units, semi-scheduled generating units and non-scheduled generating units. IRPs are able to act in several different roles and so may classify:

- scheduled bidirectional units and non-scheduled integrated bidirectional units
- scheduled generating units, semi-scheduled generating units and non-scheduled generating units
- scheduled load
- market connection points (other than market connection points which connect a market generating unit, market bidirectional unit or network service to the national grid), and
- small resource connection points (as a Small Resource Aggregator).

Generators and IRPs are also be required to classify their generating units and bidirectional units as 'market' or 'non-market'. The 'market' classification is required unless AEMO approves the 'non-market' classification. The 'non-market' classification is only permitted where the generating unit or bidirectional unit is non-scheduled and a Market Customer has classified the connection point for the plant as one of its market connection points.

F.2.4 Connection point classifications

Under the final rule, current rule 2.3 is amended extensively to provide for classification of connection points other than connection points for generating units or bidirectional units.

- The jurisdictional classification requirements and thresholds have been preserved in clause 2.3.1A and a provision added to prevent classification of connection points without appropriate authorisations or exemptions.
- The First-Tier Customer and Second-Tier Customer registration and classification categories are deleted.
- The provision for registration as a Customer have been moved to rule 2.1B.
- Clause 2.3.4 provides that:
  - the connection points for classified generating units, bidirectional units and market network services are the market connection points of the Market Participant which has classified the relevant unit or service;
  - small resource connection points which have been classified by an IRP are market connection points of that IRP;
  - end user connection points are to be classified by a Customer or an IRP, and
  - as required by the current rules, local retailers must classify the connection points of franchise customers as their market connection points.
- The final rule no longer uses the term 'market load' for classification since end users buying from retailers may both import and export electricity. The final rule removes the term 'market load' from chapter 2 and elsewhere in the NER.[190]

F.2.5 Ancillary services

Under the final rule, the ancillary service classification provisions and the Ancillary Service Provider compliance provisions in current clauses 2.2.6 (ancillary service generating units) and 2.3.5 (ancillary services load) have been merged into new clause 2.3D.

The final rule removes distinctions between classification of generating units or load for the provision of ancillary services by different Market Participant categories by allowing a Market Participant, in respect of plant at a market connection point for which it is the financially responsible Market Participant, or a Demand Response Service Provider in respect of plant connected at a market connection point, to seek its classification as an ancillary service unit. This approach is consistent with the overall approach to 'load' in the final rule. The final rule specifies that it is plant at a connection point (whether a generating unit, bidirectional unit or other connected plant) that is classified as an ancillary service unit, rather than classification of the connection point or the electrical load.

F.2.6 Market Participant labels

Consistent with the approach in the current rules, under the final rule, participant 'labels' are used to identify a Market Participant according to the plant or connection points it has classified. The following table summarises the approach under the final rule.

190 The term "market load" is preserved in Chapter 10 of the NER for the purposes of its use in the National Electricity (South Australia) Regulations.

Table F.1: **Market Participant labels**

WHAT HAS BEEN CLASSIFIED?	REGISTERED PARTICIPANT WHO MAY CLASSIFY	LABEL USED IN THE NER
scheduled bidirectional unit	Integrated Resource Provider	Scheduled Integrated Resource Provider
non-scheduled bidirectional unit	Generator or Integrated Resource Provider	Non-Scheduled Integrated Resource Provider
scheduled generating unit	Generator or Integrated Resource Provider	Scheduled Generator
semi-scheduled generating unit	Generator or Integrated Resource Provider	Semi-Scheduled Generator
non-scheduled generating unit	Generator or Integrated Resource Provider	Non-Scheduled Generator
small resource connection point	Integrated Resource Provider	Small Resource Aggregator
scheduled load	Customer or Integrated Resource Provider	Market Customer
end user connection point	Customer or Integrated Resource Provider	Market Customer
ancillary service unit	Generator, Integrated Resource Provider, Customer, Demand Response Service Provider	Ancillary Service Provider
scheduled network service	Network Service Provider	Scheduled Network Service Provider

F.2.7 Redundant classification categories removed from the NER

The final rule removes redundant classification categories from the rules. The following classification categories are removed on this basis:

- First-Tier Customers and first-tier loads
- Second-Tier Customers and second-tier loads
- non-market scheduled generating units
- non-market semi-scheduled generating units
- intending load.

F.2.8 Other consequential changes

- Some redundant provisions have been deleted (such as 2.2.2(g) and (h)) and the semi-scheduled generating unit aggregation provisions (2.2.7(i) to (l)) have been deleted in chapter 2 and moved to clause 3.8.3.
- Clause 2.3A which relates to the categories of Small Generation Aggregator and Market Small Generation Aggregator has been deleted as this registration category would be transferred into the IRP registration category, using the label 'Small Resource Aggregator'.
- Clause 2.3B, which relates to Demand Response Service Providers, has been deleted as the provisions are covered under new clause 2.1A.4 and clause 2.3.6.
- Consequential changes have been made to the Metering Coordinator registration provision (rule 2.4A) and the administration and interpretation provisions in the chapter.

F.2.9 Registration information resource and guidelines

The final rule requires AEMO to consult on certain amendments to the materials in the registration information resource and guidelines under clause 2.1.3[191] in accordance with the Rules consultation procedures. These amendments are:

- the process for applying for an exemption from the requirement to register for an exemption from the requirement to register in respect of generating systems or integrated resource systems, and
- the circumstances under which AEMO will impose terms and conditions in relation to classification under new provisions included in the final rule, being:
  - clauses 2.2.2(b1), (b3) and (b4) (alternative classifications for bidirectional units),
  - clause 2.2.7(c1) (classifications of coupled production units),
  - clause 2.3.6(g) (terms and conditions for classification of wholesale demand response units), and
  - clause 2.3D.1(g) (terms and conditions for classification of ancillary service units).

F.3 Changes to Chapter 3

Chapter 3 has been amended to introduce the new IRP registration category and bidirectional units into the market rules and to use terms such as 'load' and 'generation' in a more consistent manner. Other changes have been made to give effect to the policy for

recovery of non-energy costs.

F.3.1 Incorporation of the IRP and bidirectional units

Under the final rule, chapter 3 is amended to incorporate the new IRP registration category.

In respect of bidirectional units it has classified as scheduled bidirectional units, an IRP is a Scheduled IRP. Under chapter 3, Scheduled IRPs have the same obligations in respect of

191 Under the National Electricity Amendment (Generator registrations and connections) Rule 2021 No.12, AEMO is required to publish the initial registration information resource and guidelines under clause 2.1.3 by 21 April 2022.

scheduled bidirectional units as Scheduled Generators have in respect of scheduled generating units except as follows:

- Dispatch bids for scheduled bidirectional units, unlike dispatch bids for scheduled generating units:
  - are not required to specify an intended self-dispatch level[192],
  - are not required to specify loading and off-loading prices for quantities above and below the intended self-dispatch level[193] and
  - may contain up to 10 price bands for generation and 10 price bands for load (clause 3.8.6(g1)).
- There is no concept of slow start bidirectional units. Slow start generating units are generating units which are unable to synchronise and increase generation within 30 minutes of receiving an instruction from AEMO and must self-commit to be eligible for dispatch.[194]
- Scheduled IRPs are not required to self-commit or self-decommit (synchronise and de-sychronise from the power system) in accordance with clauses 3.8.17 and 3.8.18.

AEMO is required to prepare and publish the same type of information to the market in respect of scheduled bidirectional units as it does in respect of scheduled generating units except that the rules recognise that bidirectional units both consume and produce electricity and so bidirectional units are taken into account in respect of both their consumption and generation. For example, clause 3.7.2(f)(1) requires AEMO to take into account the load of scheduled bidirectional units in its PASA forecasts of peak load.

In respect of bidirectional units classified as non-scheduled bidirectional units:

- IRPs have the same obligations as Generators in respect of non-scheduled generating units, and
- AEMO is required to prepare and publish the same type of information to the market.

In respect of generating units an IRP classifies as scheduled generating units, semi-scheduled generating units or non-scheduled generating units, an IRP has the same obligations as a person registered as a Generator. In relation to these units, the IRP has the same label as a Generator — that is, Scheduled Generator, Semi-Scheduled Generator or Non-Scheduled Generator respectively.

In respect of small resource connection points classified by an IRP, the IRP is called a Small Resource Aggregator. A Small Resource Aggregator has the same rights that a Market Small Generation Aggregator currently has in relation to obtaining site-specific distribution factors (clause 3.6.3(b1)). It is the financially responsible Market Participant for the small resource connection points it has classified as its market connection points and contributes to the

192 The requirement for Scheduled Generators to specify an intended self-dispatch level in their dispatch bids for scheduled generating units is in clause 3.8.6(a)(1).

193 The requirement for Scheduled Generators to specify loading and off-loading prices in their dispatch bids for scheduled generating units is in clause 3.8.6(a)(3).

194 Clause 3.8.17(a).

recovery of non-energy costs in relation to any consumption of electricity at the small resource connection points it has classified as its market connection points.

In respect of end user connection points an IRP classifies as market connection points or connected plant it classifies as a scheduled load, the IRP has the same obligations as a Customer and has the label Market Customer.

F.3.2 Non-energy costs

The provisions in chapter 3 under which non-energy costs are recovered have been amended to give effect to the policy aim of determining liability to contribute to those costs according to energy flows at market connection points, rather than according to the category in which a Market Participant is registered.

A new defined term, *Cost Recovery Market Participant* is included in chapter 10. The definition covers all Market Participant categories other than a Market Network Service Provider and a Demand Response Service Provider.

The calculation of adjusted gross energy or AGE in clause 3.15.4 is replaced. AGE at a market connection point is the sum of the adjusted consumed energy (ACE, expressed as a negative value) and the adjusted sent out energy (ASOE, expressed as a positive value) at the connection point. ACE for a transmission connection point is the metered value. ACE for a distribution connection point is the metered value adjusted for distribution losses using the applicable distribution loss factor plus the unaccounted for energy allocated under clause 3.15.5.

The result is to have both a net consumption calculation for each market connection point (AGE), a gross consumption figure (ACE) and a gross generation figure (ASOE).

The cost recovery provisions have been amended to provide for Cost Recovery Market Participants to contribute to non-energy costs according to their gross consumption (ACE). These amendments are in clauses 3.15.6A (Ancillary service transactions), 3.15.8 (Funding of compensation for directions), 3.15.8A (Funding of compensation for market suspension pricing schedule periods), 3.15.9 (Reserve settlements), 3.15.10 (Administered price cap or administered floor price compensation payments) and 3.15.10C (Intervention and Market Suspension Pricing Schedule Period Settlements).

The final rule also makes drafting changes to rule 3.15.6A (Ancillary service transactions) to take a more consistent approach to the drafting and to assist readability by including headings and relocating some provisions.

Provisions inserted in chapter 3 by the *National Electricity Amendment (NEM settlement under low, zero and negative demand conditions) Rule 2021* have been deleted.

F.3.3 Drafting of ancillary service provisions

Under the final rule, Market Participants can provide market ancillary services from a broader range of plant (ancillary service units) than under the current rules, provided the relevant plant meets the market ancillary service specification. Throughout chapter 3, references to ancillary service loads and ancillary service generating units have been replaced with references to ancillary service units, which are defined in chapter 10 to include generating units, bidirectional units and other connected plant that has been classified under chapter 2 as an ancillary service unit.

F.3.4 Aggregation of units for dispatch

Under the current rules, provisions relating to the process by which units or connected plant can be aggregated for dispatch are contained in both chapters 2 and 3. Under the final rule, all provisions dealing with aggregation for dispatch are relocated to clause 3.8.3.

F.3.5 Ramp rates

The final rule proposes to amend clause 3.8.3A (ramp rates) to improve the clarity of drafting. The changes also require minimum ramp rates for scheduled bidirectional units. Scheduled IRPs are required to provide an up ramp rate or down ramp rate to AEMO in respect of both the generation and consumption of a scheduled bidirectional unit, with each being at least the *minimum ramp rate requirement* for non-aggregated units. The minimum ramp rate requirement is a new defined term and for a generating unit, scheduled bidirectional unit or scheduled load is the lower of 3MW/minute or 3% of the maximum generation provided in accordance with clause 3.13.3(b). For a scheduled network service, it remains at 3MW/minute.

The final rule also amends the minimum ramp rate requirement for scheduled load so that it is the same as for scheduled generating units and scheduled bidirectional units. This is a change to the current minimum ramp rate requirement for scheduled load of 3MW/minute.

F.3.6 Generic references to plant and participants

The final rule streamlines the drafting of chapter 3 by replacing references to specific plant or participants with more generic references where the amendment does not change the meaning of the clause. For example:

- a new chapter 10 defined term 'scheduled resource' is used where provisions apply to all plant subject to AEMO's central dispatch process (scheduled generating units, semi-scheduled generating units, scheduled bidirectional units, scheduled load, wholesale demand response units and scheduled network services), and
- references to lists of specific participants are replaced with references to Market Participants or Registered Participants.

F.3.7 Bid and offer terminology

Under the current rules, Generators and Scheduled Network Service Providers submit dispatch offers, Market Customers submit dispatch bids in respect of scheduled load and Ancillary Service Providers submit market ancillary service offers. Under the final rule, chapter 3 is streamlined by replacing:

- all references to dispatch offers with references to dispatch bids,
- all references to market ancillary service offers with references to market ancillary service bids,

- all references to default dispatch bids and market ancillary service offers with references to a new defined term - default bid (clause 3.8.9), and
- all references to bid and offer validation data with references to bid validation data.

F.3.8 Load and generation terminology

Amendments to chapter 3 and related definitions in chapter 10 have been made so that the terms 'generation', 'consumption', 'load' and 'sent out generation' are used in a consistent manner.

- The defined term 'generation' is extended to reflect its use in chapters 3 and 4 and elsewhere, so that it means, depending on context:
- the production of electrical power by converting another form of energy in a generating unit or bidirectional unit,
- the amount of electrical power (measured in MW) produced by a generating unit or bidirectional unit and measured at its terminals, or
- the amount of electrical power (measured in MW) at a defined instant at a connection point or defined set of connection points.
    - Where the rules refer to the amount of electricity supplied to the transmission network or distribution network at a connection point by a generating unit or a bidirectional unit, the term 'sent out generation' is used.
    - The defined term 'load', consistent with its current definition in chapter 10, is used in the rules where the intention is to refer to points at which electricity is delivered or to the amount of electrical power (in MW) delivered at a defined instant at a connection point or across connection points.
    - The general term 'consumption' is used to refer to end use of electricity, including when used to charge a battery.

Where the intention is to refer to MWh produced or consumed, an undefined term such as 'electricity consumed' or 'produced electricity' is used.

F.4 Changes to Chapter 4

Chapter 4 is amended to incorporate the new IRP registration category into the power system security rules. This section provides an overview of the changes in chapter 4 to incorporate Scheduled IRPs and scheduled bidirectional units, including a new power system operating procedure for dispatch of hybrid integrated resource systems.

Other changes to chapter 4 align with the changes to chapter 3 described above. References to dispatch offers are replaced with references to dispatch bids, references to market ancillary service offers are replaced with references to market ancillary service bids and changes are made to use the terms 'generation', 'load' and 'sent out generation' in a consistent manner.

F.4.1 Scheduled IRPs and scheduled bidirectional units

Except as specified below, Scheduled IRPs have the same obligations in respect of scheduled bidirectional units and integrated resource systems as Scheduled Generators have in respect of scheduled generating units and generating systems. This is given effect in the drafting either through generic references to plant and participants that include scheduled bidirectional units and Scheduled IRPs, specific inclusion of Scheduled IRPs and scheduled bidirectional units in provisions of chapter 4. The new defined term *scheduled resources* is used to refer to plant that is subject to central dispatch (other than ancillary service units) and Scheduled IRPs fall within the definition of Registered Participants and Market Participants. Where the use of generic drafting is not appropriate, Scheduled IRPs and scheduled bidirectional units are referred to expressly or, in the case of units connected to distribution networks, by using the new collective term *distribution connected units*.

Under the final rule, the obligations imposed on Scheduled IRPs in respect of scheduled bidirectional units and integrated resource systems in chapter 4 differ from those on Scheduled Generators in respect of scheduled generating units and generating systems in the following respects:

- Under clause 4.9.2(b), AEMO may instruct a Generator or IRP in relation to any of its generating units with a nameplate rating of 30MW or more, or its generating systems of combined nameplate rating of 30 MW or more in relation to transformer tap settings, voltage control settings and operation to supply or absorb reactive power. Under clause 4.9.2(b1) of the final rule, AEMO is permitted to give such instructions to IRPs in respect of bidirectional units with a nameplate rating of 5 MW or more for production or consumption, or its integrated resource systems of combined nameplate rating for either production or consumption of 5 MW.
- Scheduled IRPs do not require AEMO’s approval under clause 4.9.4(d) to synchronise or de-synchronise a scheduled bidirectional unit.
- Scheduled IRPs are not required to follow the processes for self-commitment and self-decommitment of scheduled bidirectional units under clauses 4.9.6 and 4.9.7.

F.4.2 Dispatch instructions to each scheduled resource in an integrated resource system

Integrated resource systems may comprise a combination of generating units, bidirectional units and loads. The policy aim is to allow flows between different parts of an integrated resource system even when the flows are not dispatched (for example, a solar panel could charge a battery), subject to system security requirements. To give effect to this policy aim, (clause 4.9.2A) applies to dispatch instructions to scheduled resources in integrated resource systems that comprise more than one scheduled resource (a hybrid integrated resource system). Under new clause 4.9.2A:

- an IRP for a hybrid integrated resource system could comply in aggregate with the dispatch instructions for a trading interval for two or more of its scheduled resources, except for any scheduled resource in relation to which AEMO has specified that ‘resource level compliance’ is required,

- AEMO may specify in a dispatch instruction that the scheduled resource the subject of the dispatch instruction is required to operate in accordance with that dispatch instruction (resource level compliance) where a network constraint would be violated if the scheduled resource were to operate other than in accordance with the dispatch instruction, due to technical characteristics of the scheduled resource, and
- AEMO must make a power system operating procedure setting out permitted forms of aggregated dispatch compliance by scheduled resources in hybrid integrated resource systems and arrangements for AEMO to specify when unit level compliance is required.

F.4.3 Other changes to incorporate bidirectional units

Definition of contingency events

- The definition of a contingency event in clause 4.2.3(a) includes the failure or removal from operational service of one or more bidirectional units.
- The definition of a credible contingency event in clause 4.2.3(b)(1) includes the unexpected automatic or manual disconnection of, or the unplanned reduction in capacity of, one operating bidirectional unit.
- An example of a non-credible contingency event in clause 4.2.3(e) includes simultaneous disruptive events such as multiple bidirectional unit failures.

System restart ancillary services

- The requirements for SRASs are amended to provide that sufficient SRASs should be available in accordance with the system restart standard to allow the restoration of power system security and any necessary restarting of generating units or bidirectional units following a major supply disruption (clause 4.2.6(e)).

Power system security responsibilities

- When developing the emergency frequency control schemes (EFCS) settings schedule, AEMO is required to consult with both Generators and IRPs in the case of information in the schedule relating to an over-frequency scheme (clause 4.3.2 (ha)(3)).
- For each over-frequency scheme, the applicable EFCS setting schedule is required to set out the manner in which generating units or bidirectional units will be interrupted or have output reduced (clause 4.3.2(n)).
- IRPs (as well as Generators) are required to participate in system restart tests if required by AEMO under clause 4.3.6.

Power system frequency control

- IRPs are required to ensure that all of their generating units and bidirectional units meet the technical requirements for frequency control in clause S5.2.5.11 (clause 4.4.2(b)).
- IRPs are required, in accordance with schedule 5.2 and chapter 5, to provide any necessary automatically initiated protective device or systems to protect their plant and associated facilities against abnormal voltage and extreme frequency excursions of the power system (clause 4.4.3).

- Clause 4.4.4(d) which relates to instructions by AEMO to enable inertia network services, has been amended to refer to inertia units rather than inertia generating units. Clause 4.4.5(d), which relates to instructions by AEMO to enable system strength services, is amended to refer to system strength production units rather than system strength generating units. The new defined terms 'system strength production unit' and 'inertia unit' refer to both generating units or bidirectional units registered with AEMO to provide system strength services and inertia network services (respectively) under chapter 5.

Power system security operations

- Clause 4.8.7(a)(1) is amended to require AEMO to identify the impact of a contingency event on power system security in terms of the capability of bidirectional units.
- Clause 4.8.9(a1) is amended to provide that a direction given by AEMO to a Registered Participant could be in relation to scheduled resources, ancillary service units (other than wholesale demand response units), market generating units or market bidirectional units.
- Clause 4.8.10, which provides for the process to be followed by AEMO in disconnecting units and services, is expanded to cover bidirectional units. IRPs are required to provide reasonable assistance to AEMO for the purposes of a disconnection under the rules.
- Clause 4.8.12 is amended to require each IRP to develop, and submit to AEMO for approval, local black system procedures.
- Clause 4.8.14 is amended to require IRPs to comply with local black system procedures if notified of a major supply disruption and comply with AEMO's directions or clause 4.8.9 instructions regarding the restoration of the power system.

Power system related market operations

- AEMO's load forecasts under clause 4.9.1 must include expected sent out generation from distribution connected units.

Power system security support

- Clause 4.11.1(d) has been amended to allow AEMO to require an IRP to install remote monitoring equipment to enable AEMO to remotely monitor a bidirectional unit or require upgrades, modifications or replacement of that equipment.
- Clause 4.11.1(g) has been amended to require an IRP wishing to receive dispatch instructions electronically from AEMO's automatic generation control system to comply with AEMO's requirements in relation to use of that system.

F.5 Changes to Chapter 4A

Under the final rule, chapter 4A has been amended to incorporate the IRP and bidirectional units. The final rule:

- amends defined terms as required,
- provides for IRPs to be liable entities in relation to market connection points for which they are the financially responsible Market Participant, including connection points for bidirectional units (but not generating units), and

- provides for IRPs to be subject to the Market Liquidity Obligations in respect of their production capacity.

The amendments to the definitions in Part A of the chapter replace 'generator capacity' with 'production capacity' and extend the defined term 'registered capacity' to the production capacity of a bidirectional unit.

In Part D, under which liable entities are defined, IRPs are included alongside Market Customers or the term changed to refer to the financially responsible Market Participant for the connection point. As IRPs are able to classify generating units but export from those units is not intended to be included in calculations under Part D or F, the threshold calculation excludes consumption at connection points for market generating units and at small resource connection points. Corresponding changes are made to the new entrant provisions (4A.D.3).

In Part F of chapter 4A, in the calculation of the liable load of liable entities, references to Market Customers have been changed to Market Participant. Consistent with the changes to Part D, connection points for market generating units and small generating units are excluded from the calculation.

In Part G, references to IRPs are included alongside references to Market Generators and references to bidirectional units included where appropriate. The term *generated capacity* has been changed to *production capacity*, a new term to be defined under clause 4A.G.3(b).

Drafting changes in clauses 4A.D.2(b)(2), 4A.D.3(c) and 4A.D.5(a)(3) give effect to the policy aim to ensure that 'load' is used in a consistent manner in the rules.

F.6 Changes to Chapter 5

Under the final rule, chapter 5 is amended to:

- provide for the obligations of IRPs as owners or operators of plant connected to a network, modelled on the obligations of Generators,
- implement the policy clarifications relating to TUOS charges for services provided in relation to bidirectional units,
- extend the connection arrangements to allow for the connection of bidirectional units and distribution connected bidirectional units and determination of performance standards for connected bidirectional units, and
- extend the inertia and system strength frameworks to bidirectional units.

F.6.1 Connection obligations and performance standards

As the Registered Participant in relation to connected plant, an IRP has obligations similar to those of a Generator in relation to its generating units. New clause 5.2.5A is modelled on the clause applicable to Generators (clause 5.2.5). Among other things, it requires an IRP to plan and design its facilities to ensure they are operated to comply with its performance standards, its connection agreement and the system standards. The other relevant obligations of a Generator under clause 5.2.5 also apply to the IRP under the new clause.

To support the operation of this clause, the final rule amends Schedule 5.2 of chapter 5. Schedule 5.2 sets out the conditions for connection of Generators. Under the final rule, the schedule is extended to IRPs in respect of their integrated resource systems, bidirectional units, generating systems and generating units. Changes to the schedule in the final rule include extending the technical requirements in S5.2.5 in order to apply to a bidirectional unit across its full range of operation, and in both consumption and production modes.

F.6.2 TUOS charges

To support the policy clarifications with respect to the payment of TUOS in relation to a bidirectional unit, a new clause 5.2A.6(2A) provides for Connection Applicants to request information about impediments under jurisdictional electricity legislation to the provision of a shared transmission service as a negotiated transmission service, and assistance to address them.

In clause 5.3AA(f), the term *negotiated use of system charges* is replaced with a new term, *negotiated augmentation and extension charges,* to describe more accurately the costs these charges are intended to recover. Consequential changes have been made to clauses 5.3AA(g) and clause 5.1.2(e)(2).

F.6.3 Connection and planning

The final rule amends chapter 5 to incorporate IRPs and bidirectional units in the connection arrangements under Part B and in the related schedules (Schedules 5.5 and 5.6), in the post-connection provisions in Part C of chapter 5 and in the network planning and expansion provisions in Part D and related schedules (Schedules 5.8 and 5.9). The register of large generator connections in rule 5.18A has been extended to large bidirectional connections and the register of completed distribution connected generation projects in rule 5.18B have been extended to completed connections of all distribution connected resources.

F.6.4 Inertia and system strength services

The final rule extends the provisions for the procurement of inertia services under rule 5.20B and for system strength services under rule 5.20C to bidirectional units and replaces the defined term *inertia generating unit* with a new umbrella term *inertia unit* and the term *system strength generating unit* with the new umbrella term *system strength production unit*, in each case covering generating units and bidirectional units that provide the relevant services.

F.6.5 Other changes

Consequential changes in chapter 5 update the overview table in clause 5.1.2 and provide for the consistent use of the terms load and generation.

F.7 Changes to Chapter 5A

Under the final rule, chapter 5A is amended to create consistency between the connection arrangements for distribution connected bidirectional units and the current arrangements for distribution connected generating units. These units are now referred to using a new collective term *distribution connected units* and a person that owns, controls or operates a *distribution connected unit* is referred to as a *distribution connected unit operator*.

Change to the chapter also reflect the change in registration category for aggregators of small units from Market Small Generation Aggregator to IRP (Small Resource Aggregator).

The final rule makes other changes to chapter 5A as follows:

- The defined terms *micro EG connection* and *micro embedded generator* used in chapter 5A have been renamed *micro DER connection* and *micro resource operator* respectively and both terms have been amended to refer to *distribution connected units* (clause 5.A.A.1, chapter 10).
- The defined term *non-registered embedded generator* has been renamed *non-registered DER provider* and now captures *distribution connected unit operators* that are not *micro resource operators* or Registered Participants. As a result, all rights and obligations that applied to *non-registered embedded generators* under chapter 5A before the final rule commences will apply to owners, controllers or operators of distribution connected bidirectional units in the same way as they apply to owners, controllers or operators of distribution connected generating units under the current rules.
- The Distribution Network Service Provider's obligations in relation to the connection process and connection offers for distribution connected bidirectional units has been made consistent with those for distribution connected generating units, again by using the new collective term *distribution connected unit* to refer to both *distribution connected generating units* and *distribution connected bi-directional units* (clause 5A.B.2(b)(7)(v), 5A.C.3(a)(3)(v), 5A.D.1(a)(7) and Part B of Schedule 5A.1).
- Clause 5A.D.1A has been amended to require a Distribution Network Service Provider to include all distribution connected projects in its register of completed projects, now called the register of completed resource projects.
- Clause 5.A.A.3 has been amended to deem Small Resource Aggregators to be the agent of a retail customer where there is an agreement between the Small Resource Aggregator and the retail customer relating to the retail customer's small generating unit or small bidirectional unit under which the Small Resource Aggregator is financially responsible for the market connection point at which the unit is connected to the national grid.

F.8 Changes to Chapter 6

Changes to chapter 6 incorporate IRPs and bidirectional units and give effect to the policy clarifications relating to TUOS and DUOS.

Under the final rule, chapter 6 has been amended to incorporate IRPs and bidirectional units connected to a distribution network. A new term *Distribution Connected Resource Provider* replaces *Embedded Generators* and extends it to *Integrated Resource Providers* with a distribution connected system and a new term *distribution connected unit* refers to *distribution connected generating units* and *distribution connected bidirectional units*.

- Distribution Network Service Providers are required to bill Distribution Connected Resource Providers in the same way they bill Embedded Generators under the current rules (clauses 6.20.1(a)(1) and (e)).
- Distribution Network Service Providers may require a Distribution Connected Resource Provider to establish prudential requirements for a new connection or a modification in service for an existing connection on the same basis as for Embedded Generators and Distribution Customers under the current rules (clause 6.21.1).

In order to implement the policy clarifications relating to TUOS and DUOS charges for services provided in relation to bidirectional units, new clause 6.22.2(b1) specifies the principles to be applied by the AER when determining an access dispute about the terms and conditions of access to a direct control service for a Distribution Network User other than a retail customer. The clause requires the AER to apply the principles in clause 6.7.1 as if the direct control service were a negotiated distribution service for the purposes of that clause.

Other changes to chapter 6 remove references to registration categories in the rules that are now redundant (see 'redundant classification categories' in the chapter 2), replace references to Market Small Generator Aggregators with references to Small Resource Aggregators, use new terminology for distributed energy resources (see chapter 5A summary) and correct cross-references to clauses in chapter 5.

F.9 Changes to Chapter 6B

Under the final rule, chapter 6B has been amended to change references to Market Small Generator Aggregators with references to Small Resource Aggregators and extend provisions that apply to small generating units to small bidirectional units.

F.10 Changes to Chapter 7

Under the final rule, chapter 7 has been amended to apply to IRPs and bidirectional units and Small Resource Aggregators in a manner consistent with other Market Participants.

Many of the provisions in chapter 7 apply to an IRP in its capacity as a Registered Participant, financially responsible Market Participant or Market Customer. Specific amendments have been made where the provisions apply to Generators or generating units, so as to:

- extend to IRPs the provision under which a Generator which is involved in the trading of energy is prevented from being registered as a Metering Provider for connection points where the metering data relates to its own use of energy (clause 7.4.1(e)),
- extend to Small Resource Aggregators the provision under which a Market Customer must not be registered as a Metering Provider at any connection point (clause 7.4.1(f)),
- extend to IRPs the provision under which a Generator which is involved in the trading of energy is prevented from being registered as a Metering Data Provider for connection points where the metering data relates to its own use of energy (clause 7.4.2(e)),
- extend to Small Resource Aggregators the provision under which a Market Customer must not be registered as a Metering Data Provider at any connection point (clause 7.4.2(f)),

- extend the provision specifying who may appoint Metering Coordinators for a generating system connected, or proposing to connect, to a distribution network to integrated resource systems (clause 7.6.2(a)),
- extend the requirement for type 4 metering installations to be capable of recording and providing, and configured to record and provide, trading interval energy data to all type 4 metering installations (clause 7.8.2(b1)), and
- extend the provision permitting retailers to access baseline data relating to wholesale demand response units to Small Resource Aggregators (clause 7.15.6(f))

Amendments to clause 7.8.2(f) and (g) extend the application of the requirements for metering installations for non-market generating units to non-market bidirectional units and extend the application of the requirements for metering installations for small generating units to small resource connection points (connection points at which one or more small generating units or small bidirectional units are connected).

Other change to chapter 7 in the final rule clarify provisions referring to load and generation for consistency with the load and generation changes referred to in the chapter 3 overview and remove all references to market load, as that classification has been removed from chapter 2.

F.11 Changes to Chapter 8

Under the final rule, chapter 8 has been amended to incorporate the new registration category of IRP and the Small Resource Aggregator by:

- providing that the following decisions of AEMO are not subject to dispute resolution under rule 8.2:
  - a decision by AEMO under clause 2.2.2 not to approve the classification of a bidirectional unit as a scheduled integrated bidirectional unit, a bidirectional unit as a scheduled generating unit and a scheduled load or a bidirectional unit as a semi-scheduled generating unit and a scheduled bidirectional unit (clause 8.2.1(h)(2)(ii) – (iv)),
  - a decision by AEMO under clause 2.2.3 not to approve the classification of a bidirectional unit as a non-scheduled integrated bidirectional unit (clause 8.2.1(h)(3)),
  - a decision by AEMO under clause 2.2.5 or clause 2.2.5B not to approve the classification of a generating unit as a non-market generating unit or the classification of a bidirectional unit as a non-market bidirectional unit (clause 8.2.1(h)(3A)), and
  - a decision by AEMO to reject a notice from a Small Resource Aggregator under clause 2.10.1(d1) (8.2.1(h)(5)), and
- amending the exceptions to the confidentiality provisions in rule 8.6 to provide that disclosure of NMI Standing Data by an IRP or the IRP’s Disclosees is subject to the exception in clause 8.6.2(b1). The clause currently only applies to disclosures by Customers or their Disclosees.

F.12 Changes to Chapter 9

Minor amendments have been made to the Chapter 2 jurisdictional derogations for New South Wales (clause 9.12.2), South Australia (clause 9.26), Queensland (clause 9.3.4) and Tasmania (clause 9.44) to update the cross-references to chapter 2 in those derogations.

F.13 Changes to Chapter 10

Under the final rule, chapter 10 is substantially amended. A list of the defined terms that have been added, deleted or amended is set out below and amended terms have been grouped as:

- new defined terms,
- deleted defined terms,
- amendments to reflect the changes to chapter 2 in the final rule,
- amendments to incorporate the IRP, and
- minor amendments, including amendments to address the changes in bid and offer terminology described in the chapter 3 summary above.

F.13.1 New defined terms

- Adjusted consumed energy
- Adjusted gross energy
- Adjusted sent out energy
- Affected load
- Affected Load Participant
- Affected plant
- Ancillary service unit
- Asynchronous bidirectional unit
- Asynchronous production unit
- Auxiliary load
- Basic micro DER connection
- Bidirectional unit
- Bid validation data
- Cost Recovery Market Participant
- Coupled production unit
- Default bid
- Directed resource
- Dispatched network service
- Distribution connected bidirectional unit
- Distribution connected generating unit
- Distribution Connected Resource Provider

- Distribution connected unit
- Distribution connected unit operator
- Energy constrained scheduled bidirectional unit
- Failed Small Resource Aggregator
- Inertia unit
- Integrated Resource Provider
- Integrated resource system
- Market ancillary service bid
- Market bidirectional unit
- Micro DER connection
- Micro resource operator
- Minimum ramp rate requirement
- Nameplate rating
- Negotiated augmentation and extension charges
- Network dispatch bid
- Non-market bidirectional unit
- Non-Market Integrated Resource Provider
- Non-registered DER provider
- Non-scheduled bidirectional unit
- Non-Scheduled Integrated Resource Provider
- Non-scheduled integrated resource system
- Production unit
- Rated maximum demand
- Resource minimum ramp rate requirement
- Scheduled bidirectional unit
- Scheduled integrated resource system
- Scheduled Integrated Resource Provider
- Scheduled resource
- Small bidirectional unit
- Small Resource Aggregator
- Small resource connection point
- SRA customer
- Synchronous bidirectional unit
- Synchronous production unit
- System strength production unit

F.13.2 Deleted defined terms

- Ancillary service generating unit — replaced with new definition of ancillary service unit
- Ancillary service load — replaced with new definition of ancillary service unit
- Basic micro EG connection – replaced with new definition of basic micro DER connection
- Bid and offer validation data — replaced with new definition of bid validation data
- Customer energy – term no longer used in rules
- Default dispatch bid — replaced with new definition of default bid
- Default dispatch offer — replaced with new definition of default bid
- Dispatch offer — replaced by amended definition of dispatch bid
- Dispatch offer price — replaced by amended definition of dispatch bid price
- Embedded generating unit – replaced with distribution connected generating unit
- Embedded generating unit operator – replaced with distribution connected unit operator
- Embedded Generator – incorporated in Distribution Connected Resource Provider
- Failed Market Small Generation Aggregator – replaced by definition of failed Small Resource Aggregator
- First-Tier Customer — redundant classification
- First-tier load — redundant classification
- Generating unit minimum ramp rate requirement — replaced with new definition of resource minimum ramp rate requirement
- Generation dispatch offer — replaced by amended definition of dispatch bid
- Inertia generating unit — replaced with new definition of inertia unit
- Intending load — redundant classification
- Market ancillary service offer — replaced with new definition of market ancillary service bid
- Market Small Generation Aggregator — market participant category replaced with Integrated Resource Provider (Small Resource Provider)
- MGSA customer – replaced with new definition of SRA Customer
- Micro EG connection – replaced with new definition of micro DER connection
- Micro embedded generator – replaced with new definition of micro resource operator
- Negotiated use of system charges — replaced with new definition of negotiated augmentation and extension charges
- Network dispatch offer — replaced with new definition of network dispatch bid
- Non-registered embedded generator – replaced with new definition of non-registered DER provider
- Scheduled plant — replaced with new definition of scheduled resource
- Second-Tier Customer — redundant classification
- Second-tier load — redundant classification

- Small Generation Aggregator — registration category replaced with Integrated Resource Provider (Small Resource Provider)
- System strength generating unit — replaced by new definition of system strength production unit

F.13.3 Defined terms amended to reflect chapter 2 changes to registration and classification

- Ancillary Service Provider
- Customer
- Demand Response Service Provider
- Financially responsible
- Generating system
- Generating unit
- Generator
- Market connection point
- Market Customer
- Market load
- Market generating unit
- Market Generator
- Non-market generating unit
- Non-Registered Customer
- Non-Scheduled Generator
- Non-scheduled load
- Plant
- Referred Participant
- Registration information resource and guidelines
- Scheduled Generator
- Scheduled load
- Semi-Scheduled Generator
- Small generating unit

F.13.4 Defined terms amended to incorporate Integrated Resource Provider

- Activate
- Active power capability
- Adverse system strength impact
- Affected Participant
- AGC (automatic generation control system)
- Available capacity
- Billed but unpaid charges

- Black start capability
- Capacity reserve
- Child connection point
- Connection service
- Constrained off
- Constrained on
- Constraint, constrained
- Continuous uninterrupted operation
- Control system
- Dedicated connection asset
- DER generation information
- DER Technical Standards
- de-synchronising/de-synchronisation
- Directed Participant
- Dispatch inflexibility profile
- Dispatched load
- Distribution Network User
- Distribution network user access
- Embedded Generator
- Enable
- Energise
- Energy constraint
- Energy support arrangement
- Entry service
- Excitation control system
- Export tariff
- facilities
- Frequency response mode
- GELF parameters
- General system strength impact
- generated
- Generation centre
- Generator Energy Limitation Framework (GELF)
- Generator transmission use of system, Generator transmission use of system service
- Inertia
- Inflexible, inflexibility
- Intermediary

- Intermittent
- Inverter based load
- Inverter based resource
- Key connection information
- Loading level
- Market Participant
- Market Suspension Compensation Claimant
- Market suspension pricing schedule period
- Network support payment
- Network User
- PASA availability
- Performance standards commencement date
- Planned network event
- Plant availability
- Power station
- Primary frequency response
- Rated active power
- Reactive power capability
- Regulating duty
- Releaseable user guide
- Retail customer
- Retailer insolvency costs
- Retailer insolvency event
- Scheduled reserve
- Sent out generation
- Short circuit ratio
- SRAS (system restart ancillary service)
- Supplementary carbon dioxide equivalent intensity indicator
- Supply scarcity mechanism
- Switchyard
- Synchronise
- Synchronising
- Synchronous generator voltage control
- System strength connection point
- System strength connection works
- System strength impact assessment
- Tap-changing transformer

- Transmission Customer
- Transmission Network User
- Unscheduled reserve

F.13.5 Defined terms – minor amendments

- AEMO intervention event
- Central dispatch
- Dispatch
- Dispatch bid
- Dispatch bid price
- Dispatchable unit identifier
- Enablement limit
- Energy constrained scheduled generating unit
- Energy constrained scheduled load
- Expected closure year
- generation
- Generation shedding
- load
- Loading price
- Off-loading price
- Price band
- rebid
- Registered participant
- Response breakpoint
- Response capability
- Self-dispatch level
- Very fast lower service
- Very fast raise service
- Wholesale demand response
- Wholesale demand response unit

F.14 Changes to Chapter 11

The final rule includes a new Part ZZZZU in Chapter 11 setting out transitional arrangements required to implement the rule. The key transitional provisions are:

- arrangements for existing Registered Participants in relation to integrated resource systems with related scheduled load to apply to transfer their registration to the new Integrated Resource Provider framework and to reclassify each bidirectional unit comprised in an integrated resource system under new Chapter 2 (clause 11.145.2)

- arrangements for Registered Participant who is not a Market Customer but has scheduled load to classify that load as either a Customer or Integrated Resource Provider (clause 11.145.2)
- the option for existing Registered Participants in relation to integrated resource systems with related scheduled load to apply to transfer their registration to the new Integrated Resource Provider framework (clause 11.145.2 and clause 11.145.)
- arrangements for Registered Participants in relation to new integrated resource systems to transfer automatically to the new Integrated Resource Provider framework by agreeing the new classifications of their units at the time of registration (clause 11.145.3)
- the deeming, under clause 11.145.4, of a person who immediately before the commencement of the rule is registered with AEMO as a Small Generation Aggregator to be registered with AEMO as an Integrated Resource Provider and a Small Resource Aggregator in respect of each of the small resource connection points classified by the Small Generation Aggregator immediately prior to commencement of the rule,
- provision in clause 11.145.4 for the continuing registrations and classifications for participants and plant at the commencement of the rule in order to clarify the impact of the changes to chapter 2 registration and classification arrangements on existing participants,
- the requirement under clause 11.145.5 for applications made to AEMO under chapter 2 before the effective date to be determined by AEMO under chapter 2 as amended by the new rule,
- the deeming, under 11.145.6, of generating units that immediately before the commencement of the rule were system strength generating units or inertia generating units to be system strength production units and inertia units respectively on and from the commencement of the new rules,
- the requirement under clause 11.145.9 for the market bodies (AEMO, the AER and the Reliability Panel) to amend and publish procedures, guidelines and other documents published under the Rules to take into account the new rules,
- clauses 11.145.10 to 11.145.12 to explain how new chapter 5 will apply to connection enquiries and connection applications on foot on the effective date
- clause 11.145.13 to allow for application of the new performance standards to integrated resource systems commencing the connection process after the start of the demand side arrangements under the system strength rule
- clause 11.145.14 to clarify that the final rule is not intended to affected existing connection agreements, nor require reclassification of services under those agreements
- clauses 11.145.15 and 11.145.16, establishing arrangements for early implementation of measures to allow MSGAs to provide ancillary services and for aggregated dispatch conformance.

G DESCRIPTION OF CHANGES FROM DRAFT RULE TO FINAL RULE

This appendix summarises changes between the draft and final rule. Some of these arise from changes to policy, as explained elsewhere in this determination. Others reflect new rules made by the Commission since the determination was made, which have altered the provisions being amended by the final rule compared to the draft rule. The change in implementation timing for the final rule has resulted in a revised sequencing of the commencement of the changes in the final rule compared to other rules due to commence in 2023, also resulting in changes to the provisions being amended. Technical review of the access standards for integrated resource systems have resulted in clarifications to schedule 5.2. Finally, changes from draft to final rule reflect changes in terminology used for the new Integrated Resource Provider framework and drafting corrections, clarifications and streamlining.

More detailed information about the changes is set out below, commencing with an explanation of some of the changes to terminology from draft to final rule.

G.1 Changes in terminology

As a result of consultation responses, for the final rule, the proposed term 'integrated resource unit' has been changed to 'bidirectional unit', since an 'integrated resource system' may comprise both generating units and bidirectional units. As a result, the terms used to describe the classification categories for bidirectional units have also been amended. This includes 'scheduled bidirectional unit', 'non-scheduled bidirectional unit', 'market bidirectional unit' and 'non-market bidirectional unit'.

To streamline drafting, greater use has been made of the term 'production unit' in the final rule to refer collectively to generation units and bidirectional units. For the same reason, a new term 'synchronous production unit' is used to refer to synchronous generating units and synchronous bidirectional units collectively, and the corresponding term 'asynchronous production unit' has been introduced.

The rules have historically used the term 'embedded generating unit' to refer to generating units connected to a distribution network, with several related terms such as Embedded Generator, non registered embedded generator, micro embedded generator and micro EG connection used largely in chapters 5 and 5A. The draft rule created corresponding terms for integrated resource units. For the final rule, new terminology has been introduced to replace 'embedded generating unit' and 'embedded integrated resource unit' and the related set of definitions. These changes assist to streamline drafting and are also intended to use a term for distribution connected plant that is more clearly descriptive of the facilities it applies to. The new terms are summarised in the following table.

Table G.1: **New terminology introduced in the final rule**

NEW TERMS	SUMMARY OF CHANGE
distribution connected bidirectional unit	This new term is used to refer to a bidirectional unit connected within a distribution system and not having direct access to the transmission network.
distribution connected generating unit	This term replaces *embedded generating unit* and refers to a generating unit connected within a distribution system and not having direct access to the transmission network.
distribution connected unit	A new term used to refer to collectively to distribution connected generating units and distribution connected bidirectional units.
Distribution Connected Resource Provider	A new term to replace and extend *Embedded Generator*. It refers to a Generator or Integrated Resource Provider who owns, operates or controls a distribution connected unit.
distribution connected unit operator	This new term replaces and extends *embedded generating unit operator*. It refers to a person who owns, controls or operates a distribution connected unit.
micro DER connection	This replaces *micro EG connection*, used in Chapter 5A. It refers to a connection between a distribution connected unit and a distribution network of the kind contemplated by Australian Standard AS 4777 (Grid connection of energy systems via inverters).
micro resource operator	This replaces and extends *micro embedded generator*, largely used in Chapter 5A. In general terms it refers to customers who operate, or propose to operate, a distribution connected unit for which a micro DER connection is appropriate.
non-registered DER provider	This replaces *non-registered embedded generator* and refers to a distribution connected unit operator that is neither a micro resource operator nor a Registered Participant.
basic micro DER connection service	This term is used in Chapter 5A and replaces *basic micro EG connection service*. It refers to a basic connection service for a retail customer who is a micro embedded resource operator.

Other changes in terminology are explained in context below.

G.2 Changes to chapter 2

The changes to chapter 2 have been made against an updated version of the rules that takes into account rules made since publication of the draft rule and that will come into effect before the effective date. In particular, clause 2.1.3(d) provides for the circumstances in which AEMO must consult on amendments to materials in the registration information resource and guidelines, a new instrument introduced by the National Electricity Amendment (Generator registrations and connections) Rule 2021 No. 12.

In rule 2.1B, drafting changes clarify the need to classify production units both for their scheduling status and for their market or non market status.

In rule 2.2, changes reflect amendments to the definition of 'nameplate rating' in chapter 10 to describe how the nameplate rating should be calculated for a bidirectional unit.

Clause 2.2.8, dealing with Small Generation Aggregators classifying the connection points of small generating units and small bidirectional units, has been substantially revised for the final rule, and uses the new term 'small resource connection point' to refer to a point at which, in general terms, a small generating unit or small bidirectional unit is connected and there is no retail customer load. The change reflects a change in policy between the draft and final rule. Under the draft rule, a Small Generation Aggregators was able to classify connection points that that included retail customer load. The final rule aligns more closely with the current rules under which an MSGA can only classify small generating units with a separate connection point - that is, separate from retail customer load. This allows Small Generation Aggregators to operate as wholesale market only participants, subject to obtaining any necessary authorisations or exemptions.

As in the draft rule, clause 2.2.7 of the final rule allows for the classification of coupled production units (DC coupled units) as semi-scheduled generating units subject to the conditions in the clause. The final rule adds a new condition to the effect that the maximum generation for the semi-scheduled generating unit must be limited to the maximum generation of that part of the coupled production unit that is intermittent. A corresponding change has been made in schedule 3.1.

A new paragraph in clause 2.3.1A prevents classification of connection points for retail customers unless the person has authorisations or exemptions required by a participating jurisdiction or by the National Energy Retail Law.

The final rule removes the reference to the classification of child connection points in clause 2.3.4(d). The clause was not necessary since the need for classification of child connection points as a market connection point is covered under clause 2.3.4(b).

Provisions relating to the classification of scheduled load have been clarified so that they provide for the Market Customer or Integrated Resource Provider to classify plant as scheduled load, with the approval of AEMO, rather than AEMO classifying the plant on request.

Clause 2.3D.1 deals with classification of ancillary service units. In addition to changes to clarify the drafting, an additional restriction has been added such that where more than one facility behind a connection point can provide ancillary services, they cannot be classified as ancillary service units by different people.

Rule 2.9B was introduced by the draft rule to provide for the transfer of Generators and Customers to the new Integrated Resource Provider registration category. For the final rule the clause has been amended to clarify the process, including that the usual eligibility criteria apply where a person is seeking to transfer registration under this rule. A separate process for re-registration for existing bidirectional units and existing integrated resource systems has been included in chapter 11.

Several redundant paragraphs in chapter 2 have been deleted such as clause 2.3.6(i) which restated obligations in chapter 3 to comply with dispatch instructions and parts of clause 2.3D.2(b).

G.3 Changes to chapter 3

Many changes to chapter 3 for the final rule relate to the use of new terminology such as 'bidirectional unit' and aim to take a more consistent approach when referring to the generation or consumption of plant. The chapter has also been updated to take into account rules made since publication of the draft rule.

Clause 3.6.3 deals with calculation and allocation of distribution losses. For the final rule, terminology changes in paragraph (b) have been made for consistency, but are not intended to change the meaning of the clause. For example, the clause now uses the term 'maximum demand' in relation to connection points rather than 'peak load' which is used elsewhere in the rules to refer to the load on the system as a whole.

In response to feedback and consultation, changes have been made to clauses 3.7.3(e), 3.8.4(c) and 3.8.6(g2) dealing with the provision of information by bidirectional units that are energy constrained.

For the final rule, changes have been made to the statement in clause 3.8.1(b) about the objective of the central dispatch process. The changes are intended for clarification and are not intended to alter the meaning of the clause. Similarly, proposed changes to subparagraph (8) in the clause have been reversed in the final rule in order to avoid an unintended change in meaning.

Clause 3.8.4 of the final rule provides for a separate capacity profile, and separate ramp rates, to be provided for the generation and consumption sides of a bidirectional unit. Consequential changes have been made elsewhere in the chapter. Drafting changes to clause 3.8.3A and related definitions in chapter 10 clarify how the minimum ramp rate is to be set for a bidirectional unit and to correct the drafting.

Clause 3.12.2 is to be substantially amended by the recently made *National Electricity Amendment (Compensation for market participants affected by intervention events) Rule 2021 No. 14*. The final rule makes further changes to the clause to provide for compensation to be available to an Integrated Resource Provider in relation to generation from its affected generating units or bidirectional units in the same way it would be available to a Generator. Compensation will also be available to an Integrated Resource Provider in relation to the consumption side of its bidirectional unit in the same way it is available in relation to scheduled load. The final rule also extends compensation to all affected ancillary service units, and not just those that are also scheduled for energy.

Clause 3.13.3 deals with standing data. The final rule makes drafting corrections to use new terminology in a more consistent manner and to clarify what is required from bidirectional units. A change to schedule 3.1 gives effect to the principle that the maximum generation of a DC coupled unit classified as a semi scheduled generating unit is limited to the maximum generation of the part of its unit that is intermittent.

Clause 3.13.14 deals with calculation of the carbon dioxide equivalent intensity index published by AEMO. The final rule updates the terminology in the clause and removes a paragraph (a1) which is no longer required since under the final rule, small generating units are not classified as market generating units. Instead, their connection points are classified as market connection points.

Clause 3.14.6 deals with the payment of compensation due to the application of an administered price cap or administered floor price. The final rule makes drafting corrections to incorporate the new Integrated Resource Provider categories in the manner intended.

Rule 3.15 deals with settlements including payment for non-energy costs. The final rule adopts the approach in the draft rule, with some drafting corrections and a change to the definition of *Cost Recovery Market Participant*, which no longer includes Demand Response Service Providers, consistent with the intended policy outcome. Other changes for the final rule use the new term 'Affected Load Participant', which has been introduced for the compensation payments provision in clause 3.12.2.

G.4 Changes to Chapter 4

Chapter 4 has been updated for the final rule to use the new terms such as bidirectional unit and to clarify drafting. Other changes arise from the later implementation date, since some provisions proposed to be amended in the draft rule will be omitted from the rules in 2023 by rule changes already made.

Clause 4.9.2A provides for aggregated dispatch conformance for hybrid systems. The drafting has been updated and for the final rule, the circumstances in which AEMO may require resource level conformance have been more clearly linked with the need to require resource level compliance to avoid violating a network constraint, due to technical characteristics of the relevant scheduled resource.

Clause 4.9.8 sets out general responsibilities of Registered Participants with respect to dispatch. These include requirements to ensure scheduled resources are at all times able to comply with its latest dispatch bid. The final rule allows for some streamlining by replacing the separate paragraphs for each participant type with an overarching paragraph. The final rule inserts the new paragraph and the paragraphs it is intended to replace will be removed as a minor rule change after the new paragraph is classified as a civil penalty provision.

G.5 Changes to Chapter 4A

Chapter 4A has been updated for the final rule to use the new terminology such as bidirectional unit.

G.6 Changes to Chapter 5

Chapter 5 has been updated for the final rule to use the new terms such as bidirectional unit and the new set of definitions relating to distribution connected units and their operators. To improve readability, the term 'production unit' has been used to refer to generating units and bidirectional units collectively, 'synchronous production unit' has been used to refer to synchronous generating units and synchronous bidirectional units collectively, and a corresponding term 'asynchronous production unit' has also been introduced.

The draft rule proposed a new clause 5.2A.3(b1) to clarify that a Connection Applicant should always have the option to seek a transmission service as a prescribed transmission service where there is a choice. The final rule omits the clause in light of consultation feedback, since the rules are sufficiently clear that this choice is available without the addition of the new paragraph. In its place, a new clause 5.2A.6(2A) provides for Connection Applicants to request information about impediments under jurisdictional electricity legislation to the provision of a shared transmission service as a negotiated transmission service, and assistance to address the impediments.

In the final rule, the provisions dealing with the connection of generating units and bidirectional units to distribution networks, principally clause 5.3.1A and rules 5.3A, 5.3AA and 5.18B, have been updated to use the new terminology relating to distribution connected units and their operators and, and also to apply the provisions in respect of the connection of a generating system or integrated resource system as a whole, not just the units comprising the system.

Since publication of the draft rule, the National Electricity Amendment (Efficient management of system strength on the power system) Rule 2021 No 11 has been made. The final rule has therefore been updated to take that rule into account, including the use of new terminology and a change from the proposed new term 'system strength unit' to 'system strength production unit' to avoid confusion with the separate concept, the system strength unit charge. The final rule also amends the definitions of short circuit ratio, inverter based resource and inverter based load to be introduced by the system strength rule change.

Clause 5.9.3 deals with disconnection and reconnection and the drafting has been amended for the final rule (compared to the draft rule) to avoid an unintended change in meaning.

Schedule 5.2 deals with a range of technical issues for the connection of generating systems and integrated resource systems. Follow a technical review of the amendments proposed in the draft rule, the final rule clarifies when the standards apply only to the production units within an integrated resource system, since an integrated resource system can contain sources of load as well as generating units or bidirectional units. Other changes avoid an unintended result of the draft rule, that would have resulted in standards applying to generating units with nameplate ratings less than 30 MW when not intended. The drafting has also been streamlined through the use of the terms 'production unit', 'synchronous production unit' and 'asynchronous production unit'. The final rule includes changes to the new standards in S5.2.6.15 and S5.2.5.16, introduced by the system strength rule, to extend them to bidirectional units.

G.7 Changes to Chapters 5A and 6B

Since publication of the draft rule, the National Electricity Amendment (Access, pricing and incentive arrangements for distributed energy resources) Rule 2021 No. 9 has been made, including amendments to Chapters 5A and 6B. The final rule has been updated to take those changes into account and to use the new terminology, in particular non-registered DER provider, basic micro DER connection service and micro DER connection. Chapter 5A will also be amended by the National Electricity Amendment (Efficient management of system strength on the power system) Rule 2021 No 11 and the final rule takes those changes into account.

G.8 Changes to Chapter 6

The final rule updates the drafting to use new terminology and to take into account changes made by recent rules.

G.9 Changes to Chapter 7

The final rule corrects or clarifies the changes to chapter 7 proposed by the draft rule, in light of consultation feedback and to use the new terminology such as bidirectional unit. In clauses 7.4.1 and 7.4.2, a Small Resource Aggregator will be subject to the same restrictions on becoming a Metering Provider and Metering Data Provider as a Market Customer, rather than aligning them with Market Generators. Under clause 7.15.6(f) Small Resource Aggregators will, like retailers, be given access to baseline data information relating to a wholesale demand response unit where it is the financially responsible Market Participant for the relevant connection point. Other provisions have been amended for clarification or to correct inadvertent omissions from the draft rule.

G.10 Changes to Chapter 8

Clause 8.2.1 deals with the application of the dispute resolution arrangements. Paragraph (h) includes a list of provisions that are not subject to rule 8.2. For the final rule, the list has been updated to reflect changes to chapter 2. Other changes to the chapter use the revised terminology adopted for the final rule.

In the final rule, a change proposed in the draft rule to the arrangements for consumer advocacy funding has not been made in light of consultation feedback.

G.11 Changes to Chapter 9

The draft rule proposed a change relating to Victoria's Smelter Trader, which is no longer operating and so the change has been removed from the final rule. The final rule also updates clause references in four provisions to take into account the new clause reference in chapter 2.

G.12 Changes to Chapter 10

The definitions in chapter 10 have been revised for the final rule to create and use the revised terminology explained above. New definitions that will be incorporated in chapter 10 by rules made after the draft rule was published have been included in chapter 10 and amended as required for the final rule. Other key changes made for the final rule are as follows:

- A new definition of 'Affected Load Participant' has been included for use primarily in clause 3.12.2. In that process 'Affected Participant' has also been restructured to make it easier to follow given the need to extend it to bidirectional units and Integrated Resource Providers. New terms 'affected load', 'affected network service' and 'affected production unit' also support the operation of clause 3.12.2.
- 'auxiliary load' has been revised to more clearly explain that it is intended to cover consumption other than where used as a source of the energy converted to electricity in a production unit.
- 'bidirectional unit' replaces 'integrated resource unit' and has been revised to clarify what is intended, including with respect to the meaning of 'consume' and the use of the term for a bidirectional unit that not capable of transitioning linearly from consuming to producing electricity and vice versa. Corresponding changes have been made to 'generating unit', 'integrated resource system' and 'generating system'.
- 'minimum ramp rate requirement' replaces the term 'resource minimum ramp rate' from the draft rule and has been amended to provide for the ramp rates for the consumption of a bidirectional unit, and scheduled load.
- 'minimum ramp rate' is now used to refer to the minimum ramp rate calculated using the minimum ramp rate requirement provisions.
- 'nameplate rating' includes a new paragraph to explain how this is calculated for a bidirectional unit or group of bidirectional units.
- 'plant' has been amended to use terms more consistent with other changes made for the final rule.
- 'small resource connection point' has been added to the final rule to describe the points that may be classified by a Small Resource Aggregator.
- 'Transmission Customer' has been amended, consistent with intended policy outcomes, to include Integrated Resource Providers when acting as Market Customers and in relation to supply to an integrated resource system from the grid, not just supply to bidirectional units within the system.

G.13 Changes to Chapter 11

Part ZZZZQ contains the transitional rules for the National Electricity Amendment (Access, pricing and incentive arrangements for distributed energy resources) Rule 2021. Where these rules will still be in effect following the effective date for the final rule, amendments have been made to use the new terminology for distribution connected units.

Part ZZZZS contains the transitional rules for the National Electricity Amendment (Efficient management of system strength on the power system) Rule 2021. A consequential change has been made to rule 11.143.11(c) to preserve the intended effect of the clause if a Generator in respect of plant under this clause transfers to the new Integrated Resource Provider registration category.

New Part ZZZZU contains the transitional arrangements for the final rule.

The provisions under which the Registered Participant for an existing integrated resource system will transition to new registration arrangements have been substantially revised for the final rule. The arrangements are described in more detail elsewhere in this final determination. In general terms they are intended to provide for existing integrated resource systems with related scheduled load as at the effective date, or current registration applicants for such a system, to transition to the Integrated Resource Provider arrangements through a registration application process. The arrangements are also intended to ensure that all scheduled loads (that are not classified in the new bidirectional unit category) are within the Market Customer category, in line with the approach elsewhere in the rules that assumes this to be the case, such as the compensation arrangements in clause 3.12.2. These applications will not attract a registration fee and will not be subject to testing against performance standards.

Existing integrated resource systems with non-scheduled load will be able to choose to stay in the Generator category or during the first six months after the effective date, move to the Integrated Resource Provider framework, also without a registration fee or testing against performance standards. After that six month period, the Generator will need to move to the Integrated Resource Provider framework if it modifies its plant or seeks to schedule its load.

For new applications in respect of these systems before the effective date, the applicant and AEMO will agree on the new classifications at the time of registration, allowing the transfer to the new participant category to happen automatically on the effective date.

Clause 11.145.13 provides for new Schedule 5.2 to apply when determining access standards for integrated resource systems making connection inquiries after the start of the demand side arrangements established by the National Electricity Amendment (Efficient management of system strength on the power system) Rule 2021. It will also apply to plant modifications for existing plant where the process is commenced as of that date.

Clause 11.145.14 clarifies the intended effect of the rule on existing connection agreements, which includes that the final rule is not intended to require reclassification of services provided under existing connection agreements from negotiated to prescribed (or vice versa) or alter the nature of the services provided.

Clause 11.145.15 is a transitional measure to allow for early implementation of the changes under which Small Resource Aggregators will be able to provide ancillary services, as of 31 March 2023. Clause 11.145.16 is also a transitional measure and allows for early use of aggregated dispatch conformance by hybrid systems, also from that date.