AUSTRALIAN ENERGY MARKET COMMISSION

RULE

Draft rule determination

National Electricity Amendment (Integrating price-responsive resources into the NEM) Rule 2024

National Energy Retail Amendment (Integrating price-responsive resources into the NEM) Rule 2024

Proponent

AEMO

25 July 2024

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About the AEMC

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

Acknowledgement of Country

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

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Summary

1 The Australian Energy Market Commission (AEMC or Commission) has made a draft rule to allow aggregated consumer energy resources (CER) to be scheduled and dispatchable in the National Electricity Market (NEM). This framework, named 'dispatch mode', will allow virtual power plants, community batteries, flexible large loads and other price-responsive small resources to compete with large-scale generators and storage in the NEM. It includes bidding into the market, setting spot prices, receiving and following dispatch instructions and access to markets that require scheduling (e.g. regulation frequency control ancillary services).

2 As the proportion of resources that respond to prices in the NEM becomes increasingly distributed and owned by consumers, effectively integrating these resources into the spot market is crucial to maintaining an affordable and reliable supply of electricity for all consumers. To drive participation in dispatch mode to achieve these outcomes the Commission has included short term incentive payments in the draft rule. This will be achieved through an Australian Energy Market Operator (AEMO) tendering mechanism that seeks to overcome the barriers for early entrants participating in dispatch. The Commission will be working with the Commonwealth, jurisdictions and Australian Renewable Energy Agency (ARENA) to develop short term incentives for participation. An external incentive mechanism is our first preference and if this eventuates we would remove the AEMO tendering mechanism from the final rule. In the longer term, market and network access will provide incentives for participation.

3 Many price-responsive resources will not be capable of, or choose to, participate in dispatch mode. As the magnitude of these resources grows AEMO will face further challenges forecasting demand in the NEM. To help understand the magnitude of this challenge, the draft rule introduces monitoring and reporting functions for AEMO and the Australian Energy Regulator (AER). AEMO will be required to evaluate the impact of price-responsive resources on the accuracy of its operational demand forecasts and transparently communicate improvements it makes to these. The AER will report on the efficiency consequences of these forecast inaccuracies. The reporting framework will position the market bodies and participants to evaluate the impact of price-responsive resources on AEMO's forecasts. It will also provide evidence on whether changes are required to help AEMO improve its operational demand forecasting. Alternatively, if this is not possible, a visibility market model, where retailers become responsible for forecasting their price-responsiveness.

CER are growing rapidly and the Commission has a package of reforms to support this growth

4 Australian households and businesses are embracing CER. More than three million households and businesses have solar panels and every second household is expected to have them by 2040. More than fifty thousand small-scale battery systems have been installed in the past seven years and 22 million purchases of electric vehicles are expected to be made by 2050. People are also using smart devices to control traditional assets such as hot water systems and air conditioners, and programming multiple devices in their houses through home energy management systems.

5 Developments are also occurring in the large business sector. Commercial and industrial resources (for example, commercial chillers), and new types of large loads (for example, data centres) are increasingly active in the NEM. The volume of independent small generators and batteries is also growing (for example, community batteries). Retailers and aggregators, acting on behalf of consumers, are increasingly tapping into these resources (individually or aggregated

through a VPP) to respond to market price signals.

6 Governments are seeking to achieve net zero emissions by 2050, including through policies to accelerate CER uptake. CER and distributed energy resources (DER) will play a critical role in Australia's energy transformation, helping to reduce overall system costs, improve reliability and achieve a secure, low-emission energy supply for all.

7 If these resources are integrated well, the power system will operate more smoothly, and consumers and industry will enjoy the benefits of cheaper supply. Importantly, consumers without CER will benefit from the lower system costs from integrating price-responsive resources.

8 Successful integration of CER would also mean fewer large-scale infrastructure projects would need to be constructed to keep the system running. This would contribute to the achievement of a net zero system, as existing lower emitting resources would be used rather than building new resources.

9 CER integration will require a multifaceted approach that matches the complexity of the task. Governments and energy market bodies have a plan. A CER Taskforce convened by energy ministers has developed and published an implementation plan in the form of a CER Roadmap. It defines and will help to drive the CER integration actions needed. Market bodies are driving a series of interrelated reforms that aim to integrate these resources and realise their full potential.

10 The AEMC is a member of this Taskforce, leading the 'Distribution system operation and market operation' (DSO) workstream. The AEMC will help to develop a functional map of what it will take to integrate CER into the energy system and market.

11 The AEMC is also driving keystone reforms required to effectively integrate CER into the power system for the transition to net zero in the grid, and the years beyond. These rule changes and reviews are crucial building blocks that will help to pave the way for the innovation in the market that becomes change, and the change that becomes transformation. For example, our accelerating the roll out of smart meters rule change is crucial to providing consumers with the tools to manage their CER to save money.

12 The *Integrating price responsive resources* rule change is closely related to *Unlocking CER benefits through flexible trading* rule change. This rule change:

- allows 'flexible' CER loads to be separately metered from 'passive' consumer loads such as lights and fridges in the energy market
- is expected to make it easier to participate in dispatch under this rule change. This is because it reduces the need for them to forecast passive load and conformance and compliance requirements could be easier to meet at separate settlement points.

13 This draft determination is in response to a rule change request from AEMO and is a key part of this package of reforms. It is the main rule change in the AEMC's work program that focuses on integrating these resources into the wholesale electricity market.

14 The Commission notes that for the remainder of this summary, we use the term unscheduled price-responsive resources to refer to:

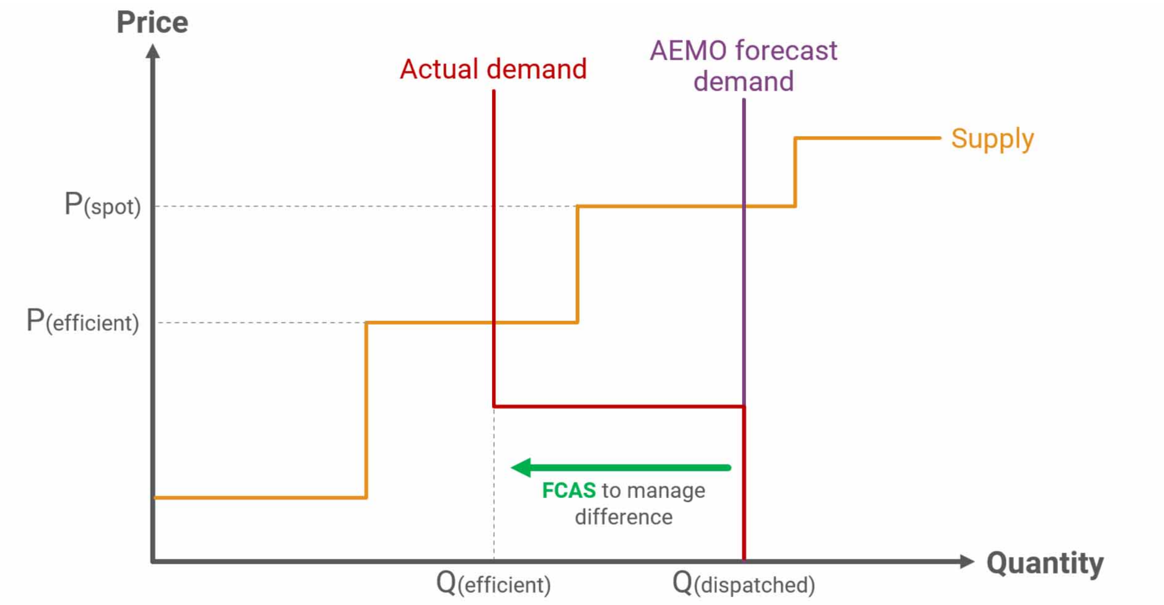
- the wide range of residential, community, commercial and industrial energy resources and load that are not currently scheduled through the market dispatch process, and
- do or could respond, individually or as part of aggregation, to market price signals.

Optimally integrating unscheduled price-responsive resources would lower total system costs by billions

15 Unscheduled price-responsive resources are not currently fully integrated into the spot market. They are not appropriately considered when determining how much energy demand needs to be met, how to meet this demand, or the price at which it is purchased. Energy, security and reliability services could be provided more efficiently if these resources were fully integrated. Over time, this would reduce the total cost of providing consumers with a reliable electricity supply and therefore decrease prices for all consumers.

16 Under existing processes, AEMO produces a price inelastic demand forecast for every dispatch interval. Figure 1 demonstrates the outcomes in prices, dispatch costs and FCAS, when unscheduled price-responsive resources respond to prices in a dispatch interval.

Figure 1: Inaccurate demand forecasts cause higher than efficient spot prices, and generation and FCAS costs



Source: AEMC

17 As AEMO does not know the intentions of these resources, it forecasts demand to determine $Q_{(dispatched)}$ and uses generator bids to achieve this level of supply. This results in a price point of $P_{(spot)}$. However, where there are unscheduled price-responsive resources that will reduce their consumption or increase generation at this price point, actual demand will be $Q_{(efficient)}$ and the efficient price would have been $P_{(efficient)}$. To balance supply with the actual demand level, frequency control ancillary services (FCAS) are required. This shows that:

- the energy spot price is higher than the efficient level and therefore consumers pay more than is necessary
- unnecessary costs were incurred by scheduled resources to meet the over forecast of demand
- costs are incurred to bring supply and demand back into balance through FCAS
- because there is a close correlation between high marginal cost generators and high emissions generators, it is likely that emissions are higher than necessary

- if demand and supply conditions are particularly tight, the demand forecast error may lead to the triggering of the reliability emergency reserve trader (RERT) and its associated costs.

18 When these operational inefficiencies are repeated they drive inefficiencies in investment timeframes. These include:

- higher energy prices, which drive inefficient investment in generation, storage and demand response
- greater demand forecast errors, which increase FCAS requirements and prices.

19 In the past, the limited amount of unscheduled price-responsive resources meant that not accounting for price elasticity in demand forecasting had little consequence. However, with the rapid uptake of CER this is changing. To quantify the magnitude of these inefficiencies in the future, the Commission tasked IES to undertake market modelling out to 2050. IES's estimates are set out in Table 1. They reveal that as the magnitude of unscheduled price-responsive resources grows, the errors become substantial, resulting in a combined efficiency loss of $1,467-1,832m. IES's full report and explanations of its modelling techniques are provided with this draft determination.

Table 1: Estimated cost reductions from integrating unscheduled price-responsive resources

Cost areas	Costs ($m, 2023, NPV)
FCAS	831-1,053
Generation	189-234
RERT	122
Emissions	325-423
Total	**1,467-1,833**

Source: IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, final report, 24 June 2024

20 IES also demonstrates that energy and FCAS prices would be substantially higher due to demand forecast errors, resulting in consumers paying $12-13b (2023, NPV) more over the period than necessary. These are not efficiency gains, they are wealth transfers from generators to consumers and therefore we do not include them in our benefit estimates. However, IES's modelling did not attempt to model the additional generation and storage entering the market and this would come with a material cost. We therefore note that the above efficiency gains are likely understated.

Our draft rule introduces dispatch mode to integrate unscheduled price-responsive into the NEM

21 The draft rule introduces a framework known as 'dispatch mode' into the NEM. This framework allows currently unscheduled price-responsive resources to be scheduled and dispatchable in the NEM, in aggregations or individually. This will allow virtual power plants, community batteries, flexible large loads and other price-responsive small resources to compete with large-scale generators and storage. It will allow them to bid into the spot market, set prices, receive dispatch instructions and earn revenue in markets which require scheduling (for example, regulation FCAS). By explicitly including currently unscheduled price-responsive resources in dispatch, AEMO will no longer need to forecast their actions in the spot market, therefore reducing demand forecast errors and their consequential inefficiencies.

22 The key features of dispatch mode and their benefits are:

- It is a purely voluntary mechanism. It is enacted in the draft rule through the concept of voluntarily scheduled resource (VSR). It allows the financially responsible market participant at the connection point to nominate a qualifying resource as a VSR and participate in central dispatch. With the mechanism being voluntary for participants, there is no requirement on consumers to participate, or more broadly, to change their behaviour or cede control of their assets in any shape or form.
- A number of small resources can be aggregated such that they are treated as one VSR for the purposes of central dispatch. This means that the VSR will be provided with, and assessed against, aggregated dispatch instructions. This means that no individual resource within dispatch mode is required to follow dispatch instructions. Instead, the participant must meet the dispatch instructions in aggregate.
- The underlying connection point classification for resources nominated as a VSR will not change. For instance, if a retailer (Market Customer) nominates one of its market connection points as VSR, this will still be a market connection point but will also have the nomination of VSR. By not creating a new classification for VSRs, or requiring a change in the classification of connection points participating, participants will have greater flexibility and implementation costs will be reduced.
- It uses the bidirectional unit (BDU) framework introduced in the *Integrating Energy Storage Systems* rule changes as the basis for the requirements in the rules. Using the BDU design allows bids for both generation and load, providing flexibility for how VSRs can operate in central dispatch.
- It follows existing conventions regarding decision making. Most importantly:
  - The NER sets out the key legal requirements for participation in central dispatch, such as bidding, dispatch and conformance. This will create certainty for market participants as the NER provides stability and familiarity through the application of existing regulations.
  - AEMO guidelines will establish the specific operational and technical details for participants to follow. This will allow AEMO to update these details more regularly than if they were placed in the rules and allow them to be tailored to the requirements of participants utilising aggregated small resources.
- It creates flexibility for dispatch mode participants through:
  - The creation of new mechanisms that allow them to drop in and out of dispatch mode smoothly. For example, it creates a hibernation mechanism where a participant could choose to participate in dispatch in summer, and drop out for winter.
  - The ability to participate at either connection points or secondary settlement points. Secondary settlement points are being created in the Commission's *Unlocking CER benefits* rule change and will sit behind a connection point, allowing the splitting of resources at a customer's premises. This means that participants can separate out flexible and inflexible resources behind a connection point and only include the flexible resources (or any combination they choose) in their dispatch mode participation.

23 The draft rule includes a time-limited incentive scheme to drive participation in the mechanism in its early years. It does this by allowing AEMO to conduct tenders to pay participants to enter dispatch mode in the first five years of the mechanism. To ensure that consumers benefit from participation, the payments are capped at a proportion of the estimated benefits of participation. Furthermore, to limit the extent of the total impact on customers the draft rule also caps the overall payments under the framework at $50m.

24 The Commission considers that this incentive scheme is necessary because of the combination of:

- the majority of the benefits from participating in dispatch mode accrue to all consumers, not the participant
- there are well recognised inherent disincentives to being scheduled in the NEM (for example being required to follow dispatch instructions)
- the mechanism is new and therefore there are likely to be positive effects on later participation from early entry.

25 The Commission considers that while necessary, this incentive framework is not a natural fit within the NER and is therefore not our ideal approach. Between the draft and final determination, the Commission will be working with ARENA, the Commonwealth and jurisdictional governments regarding alternatives to having an incentive scheme in the NER. For example, one key incentive that could be harnessed is the Commonwealth adjusting the capacity investment scheme to allow entry of dispatch mode participants (for example virtual power plants). Another option is for ARENA to provide grants to early entrants. If these are successful, the Commission would remove the incentive scheme in the final rule.

26 The Commission considers that long-term participation incentives are likely to be best provided through market and network access. For example, participants in dispatch mode should have access to the full suite of markets for services they are capable of providing. In the future, this may include access to new system security markets or access to capacity payments.

27 Much of the focus of dispatch mode has been on household based virtual power plants. However, the Commission notes that dispatch mode opens the doors to a wide variety of assets participating in the spot market. For example, we consider that the earliest entrants are likely to be aggregated mid-size batteries (for example 4.9MW). Similarly, dispatch mode opens up new opportunities for demand response to participate in central dispatch because it will smoothly facilitate retailers bidding in their customers’ demand response.

Our draft rule introduces an AEMO and AER monitoring and reporting framework for unscheduled price-responsive resources

28 The combination of the level of control required to participate in dispatch mode and the wide range of functions, capabilities and business models for CER mean that the majority of price-responsive resources are unlikely to participate in dispatch mode. The IES analysis shows that as the magnitude of these resources grow, they will create challenges for AEMO’s demand forecasting in the NEM and this may have large consequences for efficient market operation. To address these issues, the draft rule introduces a monitoring and reporting framework for AEMO and the AER. The key features of the framework are:

- Monitoring and reporting by AEMO to identify the presence and issues created by increased unscheduled price-responsive resources. This would require AEMO to report annually on the impact of this response on its operational forecasting and the measures it takes to improve it to account for unscheduled price-responsive resources.
- Monitoring and reporting by the AER to assess the efficiency implications and costs associated with actual demand deviating from forecast due to unscheduled price-responsive resources.

29 This reporting framework will provide more transparency on the materiality of deviations of actual demand from forecast and the inefficiencies that they cause. This transparency will facilitate

analysis of AEMO's operational demand forecasting methods and whether changes can reduce such inefficiencies should they materialise. Collectively, this reporting and transparency framework will help us understand how unscheduled price-responsive resources are changing and their impact on market outcomes. It will also provide evidence for the AEMC to consider whether to introduce structural changes to demand forecasting or a visibility market model in the future.

30 Before deciding on the monitoring and reporting framework the Commission assessed AEMO's proposed 'visibility mode'. This was a light-handed version of dispatch mode. It included participants submitting bids for unscheduled price-responsive resources in a similar manner to dispatch mode, but the bids would not be directly incorporated into dispatch and requirements for accuracy would be low. The Commission ruled this solution out because we considered that without direct incorporation into dispatch it would not result in substantial benefits and would still come at material cost.

31 The Commission also assessed a visibility market model where participants would bid price-responsive demand deviations into central dispatch from an AEMO price-inelastic demand forecast. The Commission considers that this solution has considerable merit and analysed it in detail. The Commission engaged Creative Energy Consulting to work up a design of this model, which is attached to this draft determination. The Commission considers the benefits of this model include:

- By transferring responsibility to market participants (for example retailers) for forecasting the price-responsiveness of their customers risks are efficiently allocated. Retailers purchase energy on behalf of customers in the spot market and on sell it to them. Generally, they possess the best information about the price-responsiveness of their customers because they have the retail contract that passes through prices and invest significant resources to know how much energy they will be purchasing at different times and price levels.
- With retailers undertaking forecasts, financial incentives could be created for accurate forecasting through the use of frequency performance payments.

32 However, after detailed design discussions with AEMO and our technical working group, the Commission concluded that this solution is not yet warranted. While the volume of unscheduled price-responsive resources is growing, it has not yet reached a point where it is materially challenging AEMO's demand forecasting and it would come with material costs to produce the necessary forecasts. We consider that the monitoring and reporting framework will place us in a good position to determine:

- when AEMO's demand forecasts are being materially challenged
- if challenges can be addressed by AEMO changing its demand forecasting methods
- whether a move to retailer-led forecasting of price-responsiveness is warranted.

Our draft rule will result in significant benefits for consumers

33 The Commission has tested whether the draft rule is in the long-term interest of consumers. To do so, we have assessed the draft rule against five assessment criteria. These criteria and our assessment of dispatch mode against them are:

- **Security and reliability** — would greater visibility and dispatchability of price-responsive resources promote a secure and reliable electricity system at the lowest cost through more accurate forecasting and operation?
    - The primary effect of dispatch mode on security is that the quantity and cost of FCAS to maintain a secure system is substantially lower. IES demonstrates that with dispatch

    mode, operational demand forecast errors are substantially lower over time, which reduces the quantity, cost and price of FCAS.
  - Dispatch mode also has benefits for the cost of maintaining a reliable supply. With certainty of the response of currently unscheduled price-responsive resources to high price events, RERT is needed less.
- **Concepts of efficiency** – to what extent will increased visibility and integration of price-responsive CER in the scheduling process lead to productive, allocative and dynamic efficiency?
  - Dispatch mode results in significant productive efficiency gains. With greater accuracy of the response of currently unscheduled price-responsive resources, less high cost generation is dispatched.
  - The decrease in operational demand forecast deviations from dispatch mode results in more efficient spot prices. These will result in allocative efficiency gains through more efficient responses in operational timeframes. Furthermore, these more efficient prices will be lower and less volatile. They therefore result in dynamic efficiency gains through signalling the need for less generation, storage and demand response in investment timeframes.
- **Emissions reduction** — would the solution efficiently contribute to the achievement of government targets for reducing, or that are likely to reduce, Australia's greenhouse gas emissions?
  - Because there is a close correlation between high marginal cost generators and high emissions generators, as less high cost generation is dispatched, emissions also decrease with the introduction of dispatch mode.
- **Implementation costs** — what will be the costs to participants, consumers and AEMO of implementing any solution? What will the costs be to participants, consumers and AEMO of complying with any solution over time?
  - Dispatch mode will result in costs to AEMO to implement and maintain. However, these are kept to a minimum through the use of recently implemented frameworks in the NER (for example, the bidirectional unit framework in the Integrating energy storage systems rule change).
  - Where participants choose to participate in dispatch mode they will also incur incremental costs to meet the standards and specifications. In the first five years of dispatch mode, the incentive scheme is likely to cover many of these costs for participants.
- **Flexibility** — would the solution be future-proof, resilient and able to accommodate market, technological, policy and other changes?
  - Dispatch mode is highly flexible and resilient to future market and technology changes. At its core, dispatch mode is a platform for aggregated small-scale resources to be completely integrated into market dispatch. It is flexible to a wide range of resources, technologies and business models, and therefore robust to changes to all of these factors over time.
  - Similarly, dispatch mode is resilient to future regulatory reforms. The basic functions of participants bidding the response of currently unscheduled price-responsive resources to different spot prices, and following these bids, is important under any future regulatory framework.

34 For dispatch mode, the Commission has quantified the benefits of the mechanism through market modelling. The Commission tasked IES to adapt its size of the prize modelling to include projected

uptake rates of dispatch mode and then use the same methodology as described above to estimate its benefits. There is material uncertainty regarding the uptake of dispatch mode and we therefore had IES take a probabilistic approach to modelling the benefits. IES models a high, medium and low participation scenario and then gives them weights based on the likelihood of them eventuating. This provides a weighted benefit which the Commission primarily considers for its NEO assessment. These are set out in Table 2. AEMO also provided an initial cost estimate of its costs to implement the mechanism and this is included in Table 2.

Table 2: Benefit and cost estimates of dispatch mode ($m 2023, NPV)

	Low	Medium	High	Probabilistic
Security benefits — FCAS	220	403	617	411
Reliability benefits — RERT	100	100	100	100
Productive efficiency — energy	63	120	180	121
Emissions reduction value	140	199	274	203
Total efficiency gain	**523**	**821**	**1,170**	**834**
Implementation costs	29			
Net Benefit	**494**	**792**	**1,141**	**805**

Source: IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, sensitivity modelling results, 8 July 2024

35 The Commission considers that these estimates provide a strong case that dispatch mode meets the NEO and should be implemented. Our probabilistic assessment is a net benefit of $805m. Furthermore, even in the low uptake scenario modelled by IES the net benefits of dispatch mode are $494m, an order of magnitude greater than the costs.

36 We note four other relevant factors in our NEO assessment:

1. Interaction with *Unlocking CER benefits* rule change. In addition to the estimates presented above we also had IES run sensitivities where the draft rule in the *Unlocking CER benefits through flexible trading* rule change is not made as final. This would mean that secondary settlement points are not available for participants to use to participate in dispatch mode and therefore participation would be lower. This results in a reduction in the total efficiency gains of dispatch mode from $834m to $787m. The Commission notes that it will be taking these benefits into account in the final determination of the *Unlocking CER benefits through flexible trading* rule change.
2. Participation costs. There will also be costs for participants that choose to use the mechanism. These need to be considered when weighing the overall benefits of the mechanism. However, given the large modelled benefits, and that these costs are only incurred for participants that use the mechanism, we do not consider there is a material risk that the costs would impact our overall NEO assessment.
3. Dynamic efficiency gains through avoiding unnecessary large scale generation and storage. We have not included the lower energy and FCAS prices modelled by IES in our cost-benefit assessment. In particular, IES estimates that prices would be substantially higher without dispatch mode, resulting in consumers paying $8,729m (NPV) more over the period. These are not true efficiency gains, they are wealth transfers from consumers to generators and therefore we do not include them. However, given the magnitude of higher revenues they

would likely result in additional large scale generation and storage entering the market and this would come with a material cost – a dynamic inefficiency – that should be considered in our analysis. We therefore consider that the above efficiency gains are likely understated.

4. Incentive payments. Under the draft incentive mechanism, there will be payments of up to $50m from consumers to participants in dispatch mode. However, this is a wealth transfer from consumers to participants, not an efficiency loss, and therefore (similar to the FCAS and energy prices) we do not include this in our NEO assessment.

37 We have also assessed the monitoring and reporting framework against the NEO and our assessment framework qualitatively. The main benefits from the approach are that it will position the market bodies to decide if and when changes are needed to AEMO's forecasting methods. This will include determining if structural changes to the way that forecasting is done in the NEM are needed (for example, placing responsibility on retailers). We consider that this approach is likely to result in timely reforms being made to improve demand forecasting in the NEM in the future. This has the potential to materially increase allocative, productive and dynamic efficiency in the long run. Furthermore, we consider that the analysis functions in the draft rule are ones that AEMO and the AER are likely to undertake in-house over time regardless of the draft rule. The increase in costs as a result of that being done formally and publicly is unlikely to be material.

Our draft rule provides an effective implementation schedule

38 The draft rule provides a schedule for implementation of dispatch mode, incentive mechanism and the monitoring and reporting framework. Our overriding approach has been to implement these mechanisms at the earliest possible date within AEMO and the AER's capabilities and resources. The resulting draft schedule is provided in Table 3 below.

Table 3: Draft rule implementation schedule

	2025	2026	2027
Dispatch mode	December: AEMO VSR guideline published	November: dispatch mode commences	
Incentives		November: AEMO publishes tender guidelines	January: AEMO able to commence first tender
Monitoring and reporting	December: AEMO and AER publish final reporting guidelines	April: AEMO to publish first quarterly report September: AEMO to publish first annual report December: AER to publish first annual report	September: AEMO to publish second annual report December: AER to publish second annual report

Source: AEMC

39 We note that AEMO will be releasing its high level impact assessment (HLIA) on 1 August 2024 to consult on its implementation plan for the draft rule. The purpose of the HLIA is to provide a preliminary view to participants and the AEMC on how the rule change may be implemented. This is intended to inform participants as they develop their own implementation timelines and impact assessments. We encourage stakeholders to review the draft determination and rule alongside when preparing their submissions.

We have consulted widely and deeply, and seek your views on the draft rule

40 In reaching the draft rule we have consulted extensively on AEMO's rule change request. This has included:

- publication of consultation and update papers, which we received 34 written submissions
- a public forum with 111 attendees
- more than 50 bilateral discussions and four meetings with industry working groups
- six sessions with our technical working group, comprising market body representatives, consumer groups and industry.

41 The Commission would like to thank all stakeholders for their collaborative and constructive engagement in our process so far, in particular members of the technical working group for their time and input. We note that stakeholder views and analysis have driven the solutions in the draft rule. In particular:

1. The draft rule is substantially different from AEMO's visibility proposal and the Commission's early policy development of a market based forecasting model. Stakeholders have emphasised the need for greater transparency and analysis of operational demand forecasts in relation to unscheduled price-responsive resources and this heavily influenced our move to the monitoring and reporting framework in the draft rule.
2. The Commission has been able to test the detailed design of dispatch mode extensively with stakeholders, in particular, through the technical working group. These discussions have informed and enhanced the detailed design of the draft rule.

42 The AEC and EnelX asked if altering either the Small Resource Aggregator (SRA) or Wholesale Demand Response Mechanisms (WDRM) could achieve the benefits of dispatch mode without the need for a new mechanism. The Commission considers that:

- In regard to SRAs, this is in essence what dispatch mode does. Dispatch mode allows existing registered participants to nominate their connection points as part of a VSR to allow them to be included in dispatch. The types of registered participants who could do this includes SRAs, market customers (retailers), generators and (more broadly) IRPs. As described above, the flexibility that this provides is one of the major strengths of the mechanism and results in low implementation costs for a reform of this magnitude.
- In regard to WDRM, the Commission does not consider this is feasible because it would not facilitate the broad participation sought in dispatch mode. WDRM is a mechanism to allow parties that do not pay spot prices – non-FRMPs – to access the spot price to participate in dispatch. By definition, this cannot facilitate the full range of unscheduled price-responsive resources controlled or coordinated by FRMPs (e.g. retailers) participating in central dispatch. Furthermore, WDRM requires the use of baselines. Baselines are not suited to aggregated residential customers or for highly price responsive resources like stand-alone batteries.

43 Submissions to this draft determination are due by **12 September 2024.**

44 We expect that the final determination and rule will be published by 19 December 2024.

How you should read this draft determination

45 This draft determination is deliberately set out in three layers for the different audiences interested in our work. First, if you are interested in a simply expressed overview of our entire work, this executive summary provides it. Second, for those interested in the background and reasons for our decisions:

- chapter 1 provides context for the rule change
- chapter 2 provides an explanation of the problem with the existing rules regarding integrating unscheduled price-responsive resources
- chapter 3 outlines the solutions we have reached to solve the problem
- chapter 4 sets out our rule-making tests and the evidence that these solutions best meet the NEO.

46 Third, for those in industry, market bodies, or other experts interested in the technical details of dispatch mode, incentives design or our monitoring framework, these are set out in appendices A, B and C. Additionally, Appendix D provides a summary of the draft rule and Appendix E covers the legal requirements to make a rule. The draft rule is published with this determination.

47 Important other documents for our draft determination are also available on our website. These include:

- IES size of the prize modelling, final report
- IES benefits modelling of dispatch mode, sensitivity modelling results
- Creative Energy Consulting updated visibility market model.

How to make a submission

We encourage you to make a submission

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

How to make a written submission

Due date: Written submissions responding to this draft determination and rule must be lodged with Commission by **12 September 2024**.

How to make a submission: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code **ERC0352.**[1]

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

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

Next steps and opportunities for engagement

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

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

Due date: Requests for a hearing must be lodged with the Commission by 1 August 2024.

How to request a hearing: Go to the Commission's website, www.aemc.gov.au, find the "lodge a submission" function under the "Contact Us" tab, and select the project reference code **ERC0352.** Specify in the comment field that you are requesting a hearing rather than making a submission.[5]

Final determination and rule: We expect that these will be published by 19 December 2024.

For more information, you can contact us

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

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1 If you are not able to lodge a submission online, please contact us and we will provide instructions for alternative methods to lodge the submission

2 See: https://www.aemc.gov.au/our-work/changing-energy-rules-unique-process/making-rule-change-request/our-work-3

3 Further information about publication of submissions and our privacy policy can be found here: https://www.aemc.gov.au/contact-us/lodge-submission

4 Section 101(1a) of the NEL and 258(2) of the NERL.

5 If you are not able to lodge a request online, please contact us and we will provide instructions for alternative methods to lodge the request.

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1 The Commission has made a draft determination

The Australian Energy Market Commission (the Commission or AEMC) has decided to make a more preferable draft electricity rule (and no draft retail rule) in response to a rule change request submitted by the Australian Energy Market Operator (AEMO).

This chapter provides an overview of:

- the rule change request from AEMO (section 1.1)
- the input from stakeholders that has shaped our draft determination (section 1.2)
- how this rule change fits within the Commission's consumer energy resource (CER) work program (section 1.3)
- the next steps in this process (section 1.4).

1.1 AEMO requested changes to integrate aggregated CER into the NEM

AEMO considers that over time the growing quantity of unscheduled price-responsive resources in the National Electricity Market (NEM) will play an increasingly important role in how the energy system performs. Ensuring that these resources can contribute to and operate within system requirements will be key to achieving an affordable, reliable, secure, and low emissions energy supply for all consumers in the future.

AEMO stated that its proposed mechanism would:[6]

- provide critical visibility and dispatchability services required to address complex and emerging power system challenges, avoiding the need for increasing reliance on interventions to manage system security and reliability
- enable innovation and enhanced competition in consumer service offerings, delivering supplementary revenue streams to consumers beyond existing feed-in tariffs and off-market retail demand response offerings
- harness the potential of price-responsive distributed resources, thereby facilitating the optimal allocation of resources to meet the demand for energy services over time, and
- lower costs to all consumers.

AEMO proposed changes to the National Electricity Rules (NER) to establish the new mechanism. AEMO proposed two modes in its rule change request:[7]

- **Visibility mode**: this mode was designed to allow participants to provide bids on the intentions of price-responsive resources. However, the bid would not be directly incorporated into dispatch and conformance requirements would be low.
- **Dispatch mode**: this mode was designed to integrate price-responsive resources into the NEM central dispatch and scheduling processes. Participants would be able to provide bids for their generation and load, receive and follow dispatch targets.

1.2 Stakeholder support for flexibility and incremental changes shaped our determination

The views expressed by stakeholders in response to our consultation paper, update paper, public forum, and in technical working groups and bilateral meetings have shaped our determination.

6 AEMO, Rule change request – Scheduled Lite Mechanism in the National Electricity Market, p. 1.

7 For further details on how the modes were proposed to operate, please see the Consultation Paper and AEMO rule change request.

We received 34 written submissions to a consultation paper in September 2023.[8] Stakeholders generally agreed that an increasing amount of unscheduled price-responsive resources in the NEM would result in inefficiencies and challenges for the operation of the system.[9]

However, there were several concerns raised:

- Some stakeholders expressed caution in terms of how significant the problem is at the moment. These stakeholders were concerned that AEMO had not clearly defined the problem, that it could be overstated, and recommended that the Commission seek to quantify it.[10] In response, we commissioned market modelling of the size of the inefficiencies (referred to as 'size of the prize' SoTP) out to 2050 by Intelligent Energy Systems (IES).[11] The IES modelling identified substantial benefits in addressing these inefficiencies as these resources grow. Chapter 4 describes these further.
- Many stakeholders also raised material issues with visibility mode as proposed in the rule change request. Stakeholders considered that there is significant diversity in the firmness of price-responsive resources and that visibility mode as proposed would not incorporate many of the less firm resources.[12]
- There were also concerns raised regarding the benefits of visibility mode because the information provided by participants is not proposed to be directly incorporated into dispatch demand forecasts.[13] In response to these, we commissioned an alternative visibility model by Creative Energy Consulting.[14]
- The need or lack of incentives to participate in the scheduling process was the most significant feedback. Stakeholders generally agreed that there is limited to no incentive to participate, even if the market benefits generally.[15] This has significantly shaped our investigation and our preferential rule.

Our approach to address the concerns raised and additional work were outlined in our update paper on 14 December 2023. On 19 February 2024, we held a public forum with 111 stakeholders, to discuss the benefits modelling and next steps.[16]

Stakeholders identified that this reform was complex and would benefit from additional consideration.[17] In response to this we formed the technical working group (TWG), which commenced in February 2024 and comprised 18 representatives from stakeholder groups. This included market participants, aggregators, gentailers, networks, industry bodies, Australian Renewable Energy Agency (ARENA), and academia. The TWG met on six occasions over three months, providing detailed feedback on the solutions as we developed them. Slides and minutes from the TWG meetings are available on the project page.

Our formal consultation was complemented by engagement with a diverse range of stakeholders in bilateral and multilateral discussions. Through these engagements, there was key feedback that has shaped the solutions:

8 AEMC, Integrating price-responsive resources into the NEM project page.

9 Submissions to the consultation paper, Powerlink, p. 1, Stanwell, p. 1, Shell Energy, p. 1, Mondo, p. 3, Grids, SwitchDin, p. 3, Red Energy and LumoEnergy, p. 2, Energy Queensland, p. 2, Energy Locals, p. 1, Rheem and CET, p. 3, and sonnen, p. 3.

10 Submissions to the consultation paper, Simply Energy, p. 1, Enel X, p. 2 and CS Energy, p. 2.

11 IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, final report June.

12 Submissions to the consultation paper, Evergen, p. 4, Origin, p. 2, AEC, p. 3, and AGL, p. 2.

13 Submissions to the consultation paper, Enel X, p. 2, AEC, p. 2, CEC, p. 1, Flow Power, p. 3.

14 Creative Energy Consulting, A Market Design to integrate Demand Response into NEM Pricing and Dispatch, 25 July 2024.

15 Submissions to the consultation paper, Stanwell, p.4, Fortescuse, p. 3, Evergen, p.3, Enel X, p. 4, and Flow Power, p. 4.

16 AEMC, Integrating price-responsive resources into the NEM project page which provides forum slides and Q&A.

17 Submissions to the consultation paper, Jemena, AEC, Tesla, CS Energy and the CEC.

- There are a significant range of unscheduled price-responsive resources, with varying levels of predictability and control. This impacts the likely costs and benefits of participating in dispatch and the alternatives that we have considered. Chapter 2 sets out our consideration of the range of firmness and appendix A sets out how our new framework is designed with these resources in mind.
- Improvements to current understanding of unscheduled price-responsive resources are needed. This includes understanding their impact on demand forecasting. See appendix C for our more preferable draft rule establishing a monitoring and reporting framework.
- Incentives are required to drive participation of unscheduled price-responsive resources. See appendix B.

1.3 This rule change fits within the Commission's CER work program

Australian households and businesses are embracing CER. More than fifty thousand small-scale battery systems have been installed in the past seven years and 22 million purchases of electric vehicles are expected to be made by 2050. People are also using smart devices to control traditional assets such as hot water systems and air conditioners, and programming multiple devices in their houses through home energy management systems.

Developments are also occurring in the large business sector. Commercial and industrial resources (for example, commercial chillers), and new types of large loads (for example, data centres) are increasingly active in the NEM. The volume of independent small generators and batteries is also growing (for example, community batteries). Retailers and aggregators, acting on behalf of consumers, are increasingly tapping into these resources (individually or aggregated through a virtual power plant (VPP)) to respond to market price signals.

Government are achieving net zero emissions by 2050 through policies to accelerate CER uptake.[18] CER and distributed energy resources (DER) will play a critical role in Australia's energy transformation, helping to reduce overall system costs, improve reliability and achieve a secure, low-emission energy supply for all.

If these resources are integrated well, the power system will operate more smoothly, and consumers and industry will enjoy the benefits of cheaper supply. Importantly, consumers without CER will benefit from the lower system costs from integrating price-responsive resources. Successful integration of CER would additionally mean fewer large-scale infrastructure projects would need to be constructed to keep the system running. This would contribute to the achievement of a net zero system as existing lower emitting resources would be used rather than building new resources.

CER integration will require a multifaceted approach that matches the complexity of the task. Governments and energy market bodies have a plan. A CER Taskforce convened by energy ministers developed a CER roadmap that defines and drives the CER integration actions needed.[19] Market bodies are driving a series of interrelated reforms that aim to integrate these resources and realise their full potential. The Energy Security Board's (ESB) end-of-program CER report outlined the CER reform work.[20]

The AEMC is also driving keystone reforms required to effectively integrate CER into the power system for the transition to net zero in the grid, and the years beyond. These rule changes and

18 Relevant government targets are set out in the emissions target statement.

19 Department of Climate Change, Energy, the Environment and Water, National Consumer Energy Resources Roadmap, July 2024.

20 ESB, Consumer energy resources and the transformation of the NEM, February 2024.

reviews are crucial building blocks that will help to pave the way for the innovation in the market that becomes change, and the change that becomes transformation.

Other reforms and reviews that intersect, or will intersect, with this rule change include the following.

- ***Unlocking CER Benefits Through Flexible Trading* rule change** — The *Integrating price responsive resources* rule change is closely related to *Unlocking CER benefits through flexible trading* rule change. This rule change allows financially responsible market participants (FRMPs) to create secondary settlement points, making it easier for large customers to have multiple FRMPs. Small customers would retain one retailer, but could separately meter their 'flexible' CER loads and their 'passive' loads such as lights and fridges.[21] This is expected to make it easier to participate in dispatch under this rule change. TWG members have highlighted the importance of the relationship between the two rule changes. They have indicated that forecasting passive load would be a challenge for some participants in dispatch mode and could limit participation as conformance and compliance requirements could be challenging to meet if passive loads were included.
- **The AER's guidelines on flexible export limits (FEL)** — CER connected to distribution networks are generally limited to a fixed export limit, typically 5kW for single-phase connections.[22] These fixed limits are set to a level that keeps shared generation from each CER connected within the network hosting capacity, particularly during high congestion. Given the forecast uptake of small-scale/distributed solar and batteries, distribution network service providers (DNSPs) need to manage the increase in generation within the network limits. DNSPs are investigating FELs as a mechanism to maintain the integrity of the distribution network as customer exports continue to grow. FELs can allow consumers to export more from their resources at times and locations where there is "spare" unallocated capacity rather than be restricted to (potentially lower) static limits. FELs would play an important role in how FRMPs, particularly retailers (market customers), would participate in dispatch mode. See appendix A for further commentary on this.
- **Distribution Service Operator (DSO)** — DNSPs play a key role in facilitating the provision of services from distribution connected resources to the wholesale market. The AEMC is leading the work examining the future DSO role and the different responsibilities within the CER taskforce. Through this workstream, the AEMC will help to develop a functional map of what it will take to integrate CER into the energy system and market. If there is a reform on DSOs, a number of subsequent rule changes would be required. The interaction between DSOs and the wholesale market will be important to consider through this review. DSO arrangements may impact the participation or success of dispatch mode, depending on the responsibility DSOs are given. We do not consider we should delay this rule change to wait for agreement on DSOs because we are not sure when these issues will be resolved.
- **Accelerating the roll out of smart meters** — Smart meters provide the digital foundation for a modern, connected, and efficient energy system. They are a key tool for consumers to manage their CER efficiently, providing a physical point of connection and information about how to save money using CER. A roll out is already happening, accelerating will mean more people can have a smart meter installed sooner, in a more equitable and affordable way — and with appropriate safeguards and protections in place for customers. A complementary rule change request has also been received to give customers access to real-time metering data.

21 AEMC, Unlocking CER benefits through flexible trading project page. The final determination is expected in August 2024.

22 AER, Response to flexible export limits consultation, 31 July 2023, p. 2.

- **Electricity Pricing for a Consumer Driven Future** — The AEMC is starting a broad, forward-looking review to address the important role that electricity pricing will play in delivering the CER necessary for the energy transition, as well as meeting the needs of a diverse set of customers. The review will consider how energy markets and regulatory frameworks can provide the products and services that match consumer preferences now and into the future. This forms a core component of the overall CER workplan.

1.4 Submissions are due by 12 September

We are seeking feedback on our draft determination and draft rules by 12 September 2024. There are a variety of ways to provide feedback, from participating in working groups and bilateral meetings to providing formal submissions, see summary noNumbSection.

1.4.1 AEMO will publish a draft high-level implementation assessment

AEMO will publish a draft high-level implementation assessment (HLIA) on 1 August 2024. The purpose of the HLIA is to provide a preliminary view to participants and the AEMC on how AEMO may implement its tasks under the rule change. This is intended to inform participants as they develop their own implementation timelines and impact assessments.

This document is not intended to preempt the outcomes of the ongoing rule change process. Instead, it is to add an additional element of rigour to this process. We hope stakeholders will provide feedback on this document to inform our final determination.

AEMO intends to undertake an industry briefing session on the HLIA after publication and receive submissions in response to it.

Stakeholders should read this draft determination and rule alongside AEMO's HLIA.

2 Unscheduled price-responsive resources present a problem and opportunity in the NEM

There are a wide range of energy resources (for example, batteries) that enable consumers, or parties acting on their behalf, to respond to wholesale market price signals. The increasing number and magnitude of these unscheduled resources is a significant opportunity for consumers, retailers and the broader electricity system. However, this responsiveness isn't currently integrated into the wholesale market or generally visible to the market or AEMO.

This chapter sets out:

- the types of unscheduled price-responsive resources and the expected growth of them in the future (section 2.1)
- how they create potential inefficiency in the energy market, but also an opportunity if harnessed appropriately (section 2.2).

2.1 Technology is enabling the demand-side to be more responsive to wholesale energy prices

We use the term unscheduled price-responsive resources to refer to:

- the wide range of residential, community, commercial and industrial energy resources and load that are not currently scheduled through the market dispatch process, and
- do or could respond (individually or as part of aggregation) to market price signals.

It includes:

- Household CER such as batteries, electric vehicles (EVs), flexible hot water systems and pool pumps. These resources allow consumers to generate their own energy, store it and/or adjust when they consume from the grid. Increasingly, they are also coordinated or orchestrated by retailers and aggregators.
- Smart devices that control traditional assets such as hot water systems and air conditioners, and controlling or programming their entire household use through home energy management systems.
- Industrial loads with components of controllable demand (for example smelters, foundries and manufacturing facilities) that may alter their production to change their electricity consumption. Some of these resources may be part of other schemes like the reliability and emergency reserve trader (RERT).
- Small non-scheduled generating and storage units. These include backup generators, units that can generate electricity from production byproducts and bidirectional units, such as community batteries that are below 5MW. There are currently 171 small generator sites and over 1,800 standalone and non-registered exempt generation in the NEM.[23]

For this draft rule we are focused on the party for each connection point in the NEM that is exposed to the spot price. This party is known as the financially responsible market participant (FRMP). In most cases, this is a retailer, but it can also be the owner of the resources, such as a Small Resource Aggregator (SRA) or ancillary service providers.

23 AEMO, NEM registration and exemption list (accessed 14 June 2024) Small generator sites refers to those that are exempt as they don't fulfil the requirement for automatic exemption but AEMO has granted exemption. There are approximately 1,800 active NMIs in the NEM that include standalone non-registered/exempt generation sites, including small generating units (and, post-IESS, small bidirectional units) that are exempt from the requirement to register with AEMO (automatic or by application).

2.1.1 There are varying levels of price-responsiveness

In addition to there being a wide range of resources responding to price signals, there are also a wide range of business models governing the relationship between the FRMP and the consumer. These business models have a material impact on how and when the resources are used. These allow consumers to decide between how responsive they want to be and how much control they have over it. For example:

- **Virtual power plants** (VPPs) where a number of customers are aggregated to provide services. Providers contract customers on differing basis, such as fixed payments at different periods or payment per kWh that is provided.[24] This usually entails some agreement to use the resources during certain periods or to assist customers in managing and lowering their bills. FRMPs acting on consumers' behalf, could adjust how these devices produce or consume electricity in response to wholesale market prices. This could be part of an aggregation to provide a range of services such as contingency FCAS. With these types of arrangements, the FRMP can be highly certain of its response and can do so quickly. However, mostly this is limited to a certain number of times in a year. This results in difficulty in being able to forecast different VPP responses across price events.
- **Tariffs** such as controlled loads that provide reduced charges for certain devices that can operate at lower cost times, for example pool pumps. With these types of arrangements, the FRMP has high certainty but low control. The consumer demand still needs to be provided within certain parameters.
- **Spot price pass-through** where the customer is exposed to some degree to the wholesale spot price. With these scenarios the FRMP may not have certainty that their customers will respond to price changes. In addition, it may have limited impact on their business if the customer does respond. This is because the customer ultimately pays based on the spot price and the FRMP has more limited risks than other contract arrangements.
- **Behavioural nudges** where the FRMP provides messages or other incentives to adjust demand. This could be due to significant price spikes and the FRMP offers customers an incentive (such as sporting tickets) to reduce demand. The FRMP in these scenarios may have limited certainty on the level of response that the incentive will elicit.

Through submissions and our TWG we heard that this variety can impact the level of certainty a FRMP has on the response that would be elicited. While some FRMPs control the devices and can predict the response completely, this is not always the case. TWG members noted that there is a time dimension to this as well.[25] Commercial and Industrial (C&I) customers may require that the response is for a certain period of time. For example a minimum reduction of two hours. This requires the FRMP to accurately predict future prices and commit in advance with the customers.

There is not a one size fits all response

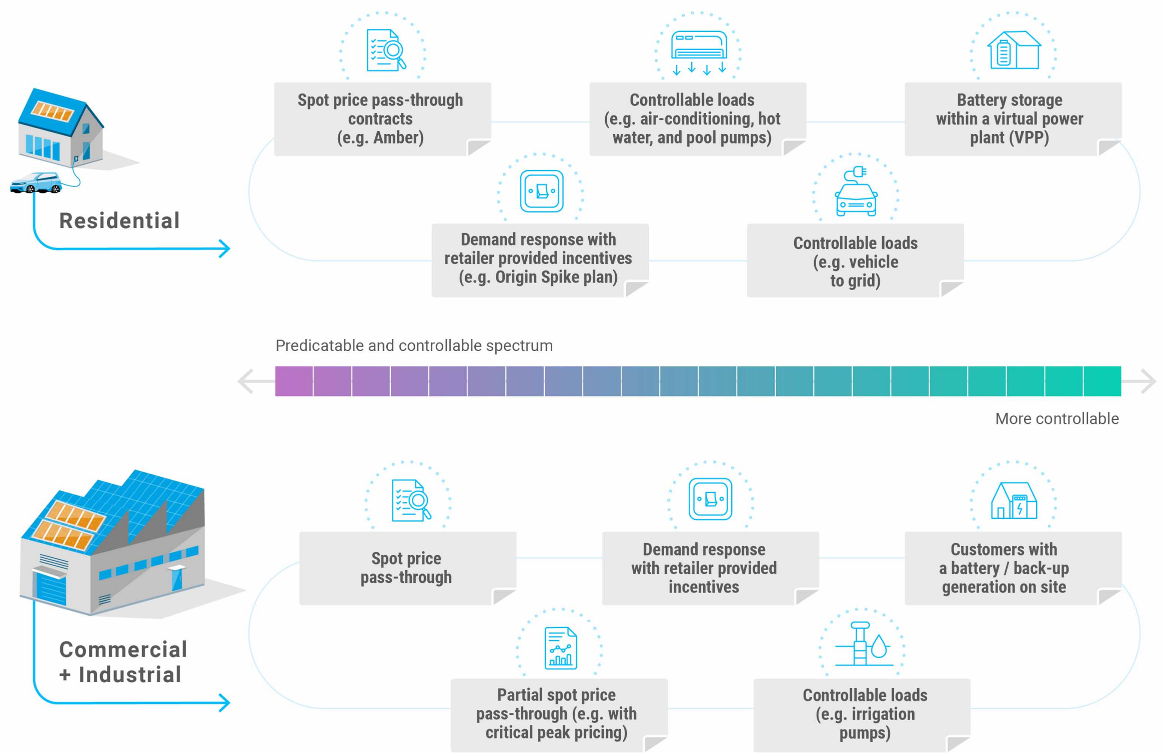
As part of the draft rule, there is a distinction that we have made based on the certainty and controllability spectrum of unscheduled price-responsive resources that may be the subject of the solutions. Those that are more predictable and controllable are more likely to be able to participate in dispatch. Most unscheduled price-responsive resources would not currently be suitable for dispatch due to not exhibiting the level of predictability and control needed.

24 Grids, 2023 DER in Energy Markets, free report.

25 AEMC, TWG meeting #2, 28 February 2024.

This is not to say that a FRMP couldn't participate in dispatch with any type of load or price-responsive resources. It is recognition of the variety of resources that exist. Figure 2.1 provides an example of the spectrum of unscheduled price-responsive resources that exist.

Figure 2.1: There is a spectrum of unscheduled price-responsive resources



Source: AEMC

For our monitoring and reporting solution (outlined in appendix C), we are focused on understanding the impact of resources that likely can't or won't participate in dispatch. This recognises that FRMPs are only likely to participate in dispatch with resources that meet a range of criteria. The concept of the dispatchability of an energy resource can be considered as the extent to which its output can be relied on to 'follow a target'.[26]

- The controllability of a resource relates to the resource's ability to reach a set point (output target) requested by an AEMO dispatch process. This could be zero megawatts, the maximum available capacity of the unit, or something in between.
- System operators need to have some level of confidence that resources are available. The firmness of a resource relates to the resource's ability to confirm its energy availability.
- The ability of the system to respond to expected and unexpected changes in the supply-demand position. For example changes in variable renewable energy generation output, generation failures, and variations in demand, over all necessary timeframes.

2.1.2 These resources are expected to grow substantially

It is difficult to estimate how many unscheduled price-responsive resources currently exist in the NEM or the extent to which they are price-responsive. AEMO reported that 5,855MW of firm

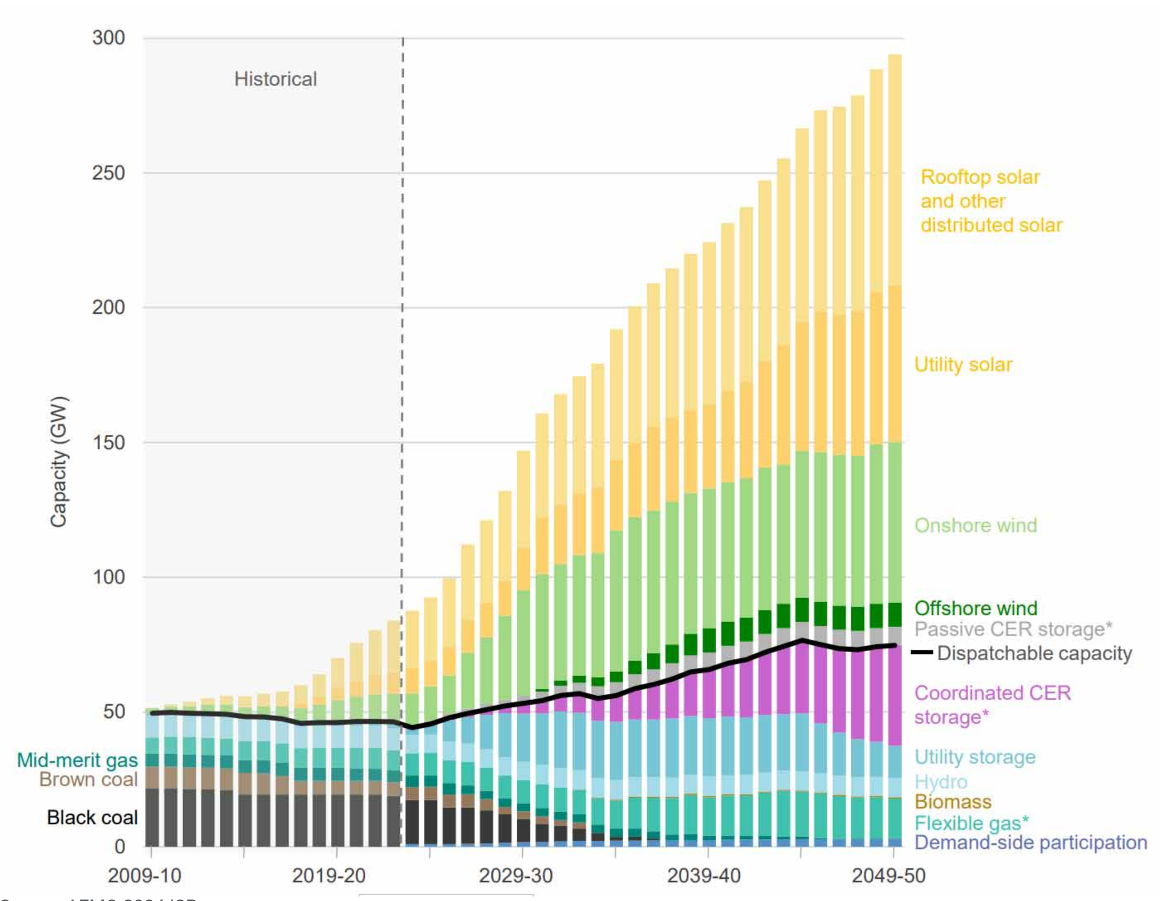
26 AEMO, Power System Requirements, 2020.

response existed in 2023, however, this includes a huge range of resources and contracts.[27] Some of it will be coordinated and some of it will not.

What is very clear is that these resources represent a growing amount and proportion of price-responsive resources in the NEM. For example, AEMO Integrated System Plan (ISP) modelling forecasts that by 2050, VPPs, Vehicle to grid (V2G) and other emerging technologies (referred to as Coordinated DER Storage) will need to provide 31GW of dispatchable storage capacity under an optimal development path.[28] We note that AEMO recently released the 2024 ISP which has updated amounts of these resources.[29]

Figure 2.2 highlights the growth in these resources (purple 'coordinated DER storage' bar) between now and 2050.

Figure 2.2: AEMO's 2024 Integrated System Plan indicates a growing amount of coordinated DER storage



Source: AEMO 2024 ISP

AEMO expects that these resources will be needed in order to operate the grid with large amounts of variable renewable energy.

27 From data gathered through the Demand-Side Participation Information Portal (DSPIP) and released through the Electricity Statement of Opportunities, 2023, p. 169.

28 AEMO, Integrated System Plan, 2022, p. 10.

29 Note that the benefits modelling and assumed participation rates throughout this report were used with the 2022 ISP as the input.

There may be some debate about the exact amount in the future, but we consider there is no doubt that the volume of coordinated unscheduled price-responsive resources is going to grow substantially.

2.2 Price-responsive resources present a problem for the operation of the wholesale market

As the volume of unscheduled price-responsive resources increases, the impact that it has on total system costs will grow. This section sets out:

- how FRMPs currently use and benefit from unscheduled price-responsive resources (section 2.2.1)
- how existing regulation and processes do not properly integrate unscheduled price-responsive resources (section 2.2.2)
- the problems that the lack of integration causes (section 2.2.3)
- IES's estimates of the magnitude of the problem (section 2.2.4).

2.2.1 How FRMPs currently use and benefit from unscheduled price-responsive resources

FRMPs purchase electricity on their customers' behalf in the spot market regardless of if they are scheduled or unscheduled. Given this exposure to wholesale market prices, FRMPs can use unscheduled price-responsive resources to reduce the costs they incur without being scheduled in the wholesale market.

FRMPs are increasingly engaging customers in arrangements to use these resources. This provides them with the ability to manage their overall load profile, provide ancillary services and as a substitute to large scale generation investments or greater hedging requirements.[30]

2.2.2 How existing regulation and processes do not properly integrate unscheduled price-responsive resources

These unscheduled price-responsive resources are not effectively integrated into the NEM. They are not appropriately considered when determining how much electricity demand needs to be met, how to meet this demand and the price at which electricity is purchased.

The energy market is not set up to consider or integrate unscheduled price-responsive resources on two fronts: it doesn't incorporate price into demand forecasting and small distributed resources cannot participate easily.

Price is not an input into demand forecasting

AEMO is responsible for determining the level of expected demand in the NEM. It does this using models in the Demand Forecasting System to best predict how demand will change under certain conditions (for example the day and time). However, it does not consider how much demand will change as the price changes.[31] This is partly due to customers not responding to spot prices in the past. Most customers were on flat pricing and therefore faced limited incentive to move their consumption to different periods. Furthermore, on the small consumer side, many of the resources which are capable of responding to prices now and in the future were not available. As such, price has not featured as a sensitivity in demand forecasting in the NEM to date.[32]

30 See for example AGL, FY 24 half-yearly results, slide 19.

31 AEMO, power system operating procedures, accessed 26 June 2024.

32 AEMC, TWG meeting #2, 28 February 2024.

An added complexity is the impact of including price changes into demand forecasting. If AEMO makes assumptions about the level of response to a given high (or negative) price, it would signal to the market the adjusted price. This adjusted price includes a response to avoid the high or low price that the market was unaware of. However, the response may not actually materialise at this adjusted price, resulting in the less efficient market outcome.

With this forecast demand amount (without price sensitivity) AEMO orders the offers from scheduled participants, from least to most expensive, and determines which resources will be dispatched. AEMO will dispatch generators needed to meet expected customer demand at the lowest cost.

Small distributed resources cannot participate in central dispatch easily

Since the start of the NEM, with some exceptions, the NER has required generators greater than 30 MW to be either scheduled or semi-scheduled.[33] In 2021, the Commission decided that batteries above 5MW would be required to be scheduled for their load and generation.[34]

Many of the requirements of being dispatched exclude or result in significant costs for smaller resources. For example:

- The minimum bidding amount is 1MW. For resources that are smaller than 1MW, this rules out their participation. For resources that are greater than 1MW but still not significant, it limits how much they can participate during different periods depending on the current status and capability.[35]
- Onerous requirements to communicate with AEMO. Current arrangements best suit participants that have telemetry connections through network service providers (NSP) using the Inter-control Centre Communications Protocol (ICCP). Smaller, non-NSP connected providers face a number of barriers to connecting and, ultimately accessing markets such as regulation FCAS.
- Larger scheduled generators are designed for constant participation in central dispatch. If they experience an issue they can disconnect from the grid to resolve it. Their primary, and potentially sole, purpose is to sell energy. Small aggregated resources (such as VPPs) are usually participating as a secondary function (for example, their primary function is usually providing energy to the household which needs to remain connected). There is not the same ability to disconnect from the grid if there are technical issues because they need to continue being supplied energy from the grid.

Due to size of the individual resources and the temporal nature of when they are price-responsive, the current mechanisms may not suit these resources to formally engage with the wholesale market. This means that while resources controlled by the same market participant could, in aggregate, be over the generator threshold, they cannot participate on the same level or do not have to meet the same requirements. There is no requirement for them to participate in the wholesale energy market. They are also unable to compete with large-scale generators and storage, even though they may have the capabilities.

33 AEMO, Guide to generator exemptions and classification of generating units, 2022.

34 AEMC, Integrating Storage into the NEM, 2 December 2021, p. 20.

35 Grids, submission to the consultation paper, p. 5.

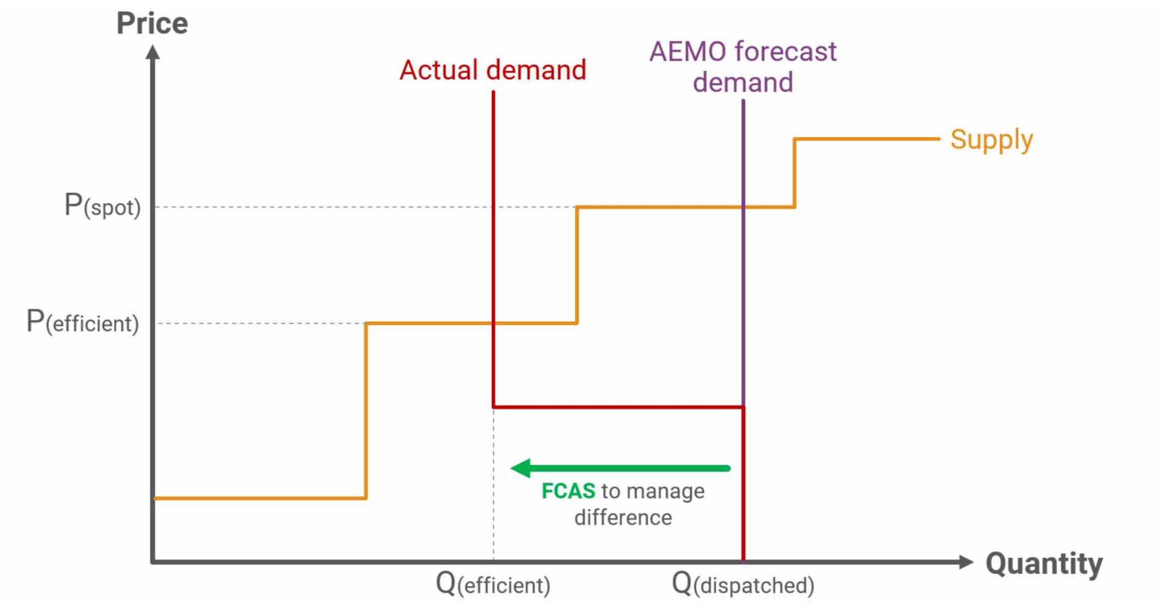
2.2.3 The problems that the lack of integration causes

As unscheduled price-responsive resources increase, if current processes are maintained, we expect to see increasingly inefficient market outcomes. This will primarily be driven by the inability to accurately determine the level of demand that needs to be met.

In submissions, stakeholders agreed that not integrating these resources effectively would create material challenges. Mondo said that we should avoid a system where these resources operate in opposition to the market.[36]Other submissions went further and noted that it also impacts the operation of other players. Sonnen highlighted that pre-dispatch accuracy has a disproportionately material impact on smaller players as they are less likely to use alternative forecasting, reducing their ability to efficiently use CER flexibly for its customers.[37]

Figure 2.3 provides a stylised example of the outcomes in dispatch costs, prices and FCAS use, when price-responsive resources are not included in the market demand forecast. As AEMO does not know the intentions of these resources, it forecasts demand to determine $Q_{(dispatched)}$ and uses generator bids to achieve this level of supply. This results in a price point of $P_{(spot)}$. However, where there are unscheduled price-responsive resources that will reduce their consumption or increase generation at this price point, actual demand will be $Q_{(efficient)}$ and the efficient price would have been $P_{(efficient)}$. To balance supply with the actual demand level, frequency control ancillary services (FCAS) are required.

Figure 2.3: Inaccurate demand forecasts cause higher spot prices, generation and FCAS costs



Source: AEMC

The outcomes as a result of the above scenario are:

1. the energy spot price is higher than the efficient level and therefore consumers pay more than is necessary
2. unnecessary generation costs were incurred to meet the over forecast of demand
3. costs are incurred to bring supply and demand back into balance through FCAS

36 Mondo, submission to the consultation paper, p. 3.

37 sonnen, submission to the consultation paper, p. 3.

4. because there is a close correlation between high marginal cost generators and high emissions generators, it is likely that emissions are higher than necessary
5. if demand and supply conditions are particularly tight, the demand forecast error may lead to the triggering of RERT and its associated costs.

When these operational inefficiencies are repeated they drive inefficiencies in investment timeframes. These include:

- higher energy prices cause inefficient investment in generation, storage and demand response
- greater demand forecast errors increase FCAS requirements and prices.

Box 1 provides a simplified example of the impact of not integrating these resources.

Box 1: Example of the impact of unscheduled price-responsive resources

Take, for example, a retailer (or FRMP) with a number of price-responsive customers. The customers and FRMP have an agreement to reduce consumption or increase exports at certain prices. This could primarily be to minimise customers bills.

During a high price time, responsiveness from its customers benefits the FRMP. This occurs as the FRMPs overall quantity of energy that they must pay for is lower during the high price time. The FRMPs customers also benefit as they would have paid more for energy during this period had they not responded. Additionally, (or alternatively depending on the arrangement), they may receive payments from the FRMP for producing or exporting energy during this time.

Currently, only the FRMP and its customers benefit.

The level of response was not known to the market operator or other participants. The market was operated assuming that there wasn't going to be changes in demand based on prices. The level of response that the FRMP (and its customers) made, could have had an impact on the price during that period.

If the lower level of demand was accounted for, the overall demand that needed to be met would have been lower. As a result less generation, and potentially less expensive generation, could have been used. This could reduce total system costs and lower the price of energy during that time.

If this could be achieved, then in the long term system costs would be lower for everyone. As these resources grow, the number of times and size of the impact is expected to grow. Importantly, FRMPs or customers don't need to change their behaviour or intentions to achieve this—the system just needs to operate more efficiently.

Source: AEMC

2.2.4 IES's estimates of the magnitude of the problem

We engaged IES to answer the question "what is the size of the potential benefit (or 'size of the prize', SoTP) of better integrating unscheduled price-responsive resources into the NEM from 2025 to 2050?".[38] The IES modelling simulated the anticipated benefits over time from integrating forecast increases in price-responsive resources into market processes.

IES modelled three different potential worlds between 2025 and 2050.

- **Base case** – this is the no reform world, where no rule change is made. AEMO's forecasting systems attempt to identify potential price-responsive resources in its demand forecast without specific reliable information in operational timeframes. Substantial increases in these

38 IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, final report, 24 June 2024.

resources over time lead to material demand forecasting errors and consequential inefficiencies.

- **Visibility** – this is a generic visibility reform. It has the following core features, but is not related to a specific visibility proposal. Price-responsive resources remain unscheduled and are not dispatched by AEMO. However, participants submit information in operational timeframes to AEMO which reduces demand forecasting errors. The lower barriers to entry incentivise higher participation than the dispatch world. However, this is offset by lower forecast accuracy than in the Dispatch world.
- **Dispatch** – this is a generic dispatch reform. It has the following key features. Resources are integrated into central dispatch and scheduling processes. Modelling assumed higher barriers to entry than visibility, resulting in lower participation. However, participation in central dispatch means higher forecast accuracy and higher participation in frequency control markets because of dispatchability.

By comparing these scenarios we can understand the benefit that integrating these resources can have to the energy system, and the change in emissions.

Box 2: IES approach to modelling benefits

IES market modelling quantified the benefits of integrating unscheduled price-responsive resources into the NEM dispatch process. The modelling was conducted in PLEXOS to simulate a Base case and two representative reform options, visibility and dispatch. The modelling focused on the impacts for VPPs and Demand Side Participation (DSP):

- VPP: represents the ISP values for aggregated embedded storage and V2G. These resources were modelled with perfect foresight and operate to meet system conditions, consistent with the ISP.
- DSP: is the same as the ISP and represents a wide range of resources and consumer behaviour to reduce demand during infrequent high price events.

The benefits of integrating VPPs and DSP were modelled separately across the three cases due to the difference in nature of their operations. VPPs are expected to operate regularly throughout the year, whereas DSP are expected to trigger infrequently and only during high price events. Across all scenarios the actual VPP and DSP and operations, and therefore actual scheduled demand, remained the same.

Our base case modelled a scenario where price-responsive resources remain unscheduled and AEMO is required to forecast their operation. For instance, lower levels of forecast VPP contribution to evening peak result in additional scheduled generation. This results in imbalances between the dispatched generation and demand.

The two reform cases modelled different rates of VPP participation in dispatch, resulting in lower forecasting errors. Using the example above the VPP contribution to the evening peak is included in the dispatch calculation and the correct amount of generation is dispatched.

Source: AEMC

The IES market modelling demonstrates that if these resources could be perfectly integrated, it is likely to result in significant benefits.[39] IES estimates cost savings of between $1.4 and $1.8b net present value (NPV, 2023) to 2050. These efficiency gains are made up of:

- lower FCAS requirements (between $831m and $1,053m NPV);
- lower use of scheduled generation

39 IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, final report, 24 June 2024.

    - resulting in lower emissions (between $325m and $423m NPV), and
    - lower generation costs (between $189m and $234m NPV), and
- lower requirements for emergency reliability measures ($122m NPV).

In addition, reform is expected to lower spot prices (between $12b and $13b NPV) and FCAS prices (between $678m and $814m NPV). IES's modelling held market entry constant between the scenarios. Given the magnitude of higher revenues they would likely result in additional market entry and that this entry would come with a material cost. We therefore note that the above efficiency gains are likely understated.

Additional generation could be required if we do not integrate these resources into processes

In its rule change request AEMO identified an alternative approach to understand what the system would require if we don't integrate unscheduled price-responsive resources – that is requiring additional investment in large scale firming capacity.[40] AEMO stated that needing to duplicate the projected coordinated price-responsive resources through investment in additional shallow grid-scale storage would cost between $1.8b and $4.4b.

The 2024 ISP sensitivity analysis of not having coordinated CER also indicates that $4.1b of assets would need to be duplicated.[41]

40 AEMO, Rule change request – Scheduled Lite mechanism in the National Electricity Market, pp. 38 and 62.

41 AEMO, 2024 Integrated System Plan - A roadmap for the energy transition.

3 Our draft rule integrates unscheduled price-responsive resources into the NEM

Chapter 2 highlighted that:

- there are growing amounts of unscheduled price-responsive resources in the NEM
- if current NEM systems and processes are not updated, these will have a significant impact on total system costs.

To reduce the problems identified there are two potential options:

- Improve forecasting of unscheduled price-responsive resources. This would ensure that demand forecasts integrate price-responsive resources and an efficient amount of generation is dispatched to meet demand.
- Include more (currently) unscheduled price-responsive resources as scheduled resources. This would directly include price-responsive resources capable of participating in dispatch. AEMO would no longer need to forecast their actions and would receive frequent data from participants, therefore reducing inefficiencies.

The Commission's draft rule integrates unscheduled price-responsive resources into the NEM using both of these options. This chapter explains our draft rule and the reasons for it. It is structured as follows:

- options to integrate unscheduled price-responsive resources, section 3.1
- why and how we propose to:
    - allow participants to nominate qualifying resources as a Voluntarily Scheduled Resource (VSR) to participate in central dispatch processes, known as 'dispatch mode', section 3.2
    - provide incentives to participants, section 3.3
    - create a monitoring and reporting framework to assess the impact of resources that remain unscheduled, section 3.4.

3.1 There are two options to integrate unscheduled price-responsive resources

The Commission considers that solutions need to be put in place now to prepare for the increasing amount of unscheduled price-responsive resources. When considering how to address the impact of growing amounts of unscheduled price-responsive resources, two options are available: improving supply information or improving demand forecasting.

1. Improve supply information by scheduling the price-responsive resources that are capable of being dispatched.
    a. Pro: information from scheduled resources provides AEMO with the current position on energy demand in the NEM. It directly improves demand forecasting. By explicitly including unscheduled price-responsive resources in dispatch, AEMO will no longer need to forecast their actions in the spot market and therefore inefficiencies will be reduced.
    b. Cons: Many unscheduled price-responsive resources are not capable of being dispatched. For those that are capable, there are material costs to being scheduled. Furthermore, because the majority of benefits from resources being scheduled accrue to the market as a whole, not the participant, there is a challenge incentivising scheduling.

2. Improving forecasting of unscheduled price-responsive resources. This could be achieved in a few ways:
   a. AEMO explicitly incorporates price elasticity in its operational demand forecasts
      i. Pros: this is likely a lower-cost system upgrade solution.
      ii. Cons: it is likely very challenging to accurately predict responses at different price levels. To do so would require AEMO to be able to predict the response of the wide range of business models and resources highlighted in chapter 2 across the entire NEM.
   b. Participants become responsible for providing information about the price-responsiveness of their customers to AEMO (for example the visibility market model that we developed and investigated)
      i. Pros: information is likely to be more accurate as it is being provided by the FRMP that has control and information over its contracts and positions.
      ii. Cons: it requires changes to how demand forecasting is currently done by AEMO and require FRMPs to provide information to AEMO. This could be costly for both.

Our draft rule includes option 1 and a reporting framework intended to help AEMO develop option 2(a), given the range of unscheduled price-responsive resources that exist.

3.2 We are enabling predictable and controllable price-responsive resources to be integrated into dispatch

Our draft rule creates a voluntary framework, known as 'dispatch mode', for unscheduled price-responsive resources (for example VPPs) to participate in dispatch.[42] This will allow FRMPs to provide bids, receive and follow dispatch instructions, access regulation FCAS and frequency performance payments, and be involved in setting the spot price with these resources. By explicitly including currently unscheduled price-responsive resources in dispatch, AEMO will no longer need to forecast their actions in the spot market and therefore the inefficiencies caused by errors in these forecasts will be removed.

Our draft rule has the following key features and benefits:

- It is a purely voluntary mechanism. The draft rule introduces the concept of VSRs. It allows the FRMP at the connection point to nominate a qualifying resource as a VSR and participate in central dispatch. With the mechanism being voluntary for participants, there is no requirement on consumers to participate, or more broadly to change their behaviour, or cede control of their assets in any shape or form.
- A number of small resources can be aggregated such that they are treated as one VSR for the purposes of central dispatch. This means that the VSR will be provided with, and assessed against, aggregated dispatch instructions. No individual resource within that VSR is required to follow dispatch instructions. Instead, the VSR must meet the dispatch instructions in aggregate.
- The underlying connection point classification for resources nominated as a VSR will not change. For instance, if a retailer (Market Customer) nominates one of its market connection points as VSR, this will still be a market connection point but will also have the nomination of VSR. By not creating a new classification for VSRs, or requiring a change in the classification

42 We use 'dispatch mode' to refer to the package of draft rule amendments to incorporate voluntarily scheduled resources, namely amendments to chapters 3, 4, 4A and 10.

of connection points participating, participants will have greater flexibility and implementation costs will be reduced.

- It uses the bidirectional unit (BDU) framework introduced in the Integrating Energy Storage Systems (IESS) rule change as the basis for the VSR requirements in the rules. Using the BDU design allows bids for both generation and load, providing flexibility for how VSRs can operate in central dispatch.
- It follows existing conventions regarding decision-making. Most importantly:
  - The NER sets out the key legal requirements for participation in central dispatch, such as bidding, dispatch and conformance. This will create certainty for market participants as the NER provides stability and familiarity through the application of existing regulations.
  - AEMO guidelines will establish the specific operational and technical details for participants to follow. This will allow AEMO to update these details more regularly than if they were placed in the rules and allow them to be tailored to the requirements of participants utilising aggregated small resources.
- It creates flexibility for participants (referred to as Voluntarily Scheduled Resource Providers, or VSRPs) through:
  - The creation of new mechanisms that allow them to drop in and out of dispatch smoothly. For example, it creates a hibernation mechanism where a participant could choose to participate in dispatch in summer, and drop out for winter.
  - The ability to participate (and aggregate) at either connection points or secondary settlement points. Secondary settlement points are proposed to be created in the Commission's *Unlocking CER benefits through flexible trading* rule change and will sit behind a connection point, allowing the splitting of resources at a customer's premises. This means that participants can separate out flexible and inflexible resources behind a connection point and only include the flexible resources (or any combination they choose) in their VSR.

The provisions on voluntarily scheduling in the draft rule are largely consistent with the proposed 'dispatch mode' in AEMO's rule change request.[43] The draft rule provides a similar approach for aggregated distributed resources to participate in central dispatch processes. As such it achieves the objective of integrating currently-unscheduled price-responsive resources in the NEM.

In consultations there were concerns raised that being dispatched would significantly amend or limit what unscheduled price-responsive resources could do. We do not consider this to be the case. Box 3 outlines what participating in dispatch means for a FRMP.

Box 3: Being dispatched is doing what you said you wanted to do

Being dispatched simply means:

- That you told AEMO that you wanted to consume or export a certain amount of energy at certain price points.
- The price point that you submitted was at or lower than the price point to clear the market at the time. Therefore, you are dispatched by AEMO to do what you submitted to do at that price point.

Generally, if a participant doesn't want to consume or export, they can bid zero amounts of energy.

43 AEMO, Rule change request – Scheduled Lite Mechanism in the National Electricity Market, p. 14.

Alternatively if they want to consume or export, regardless of the price, they can bid the cap or floor price. In normal circumstances, they will be dispatched to the level they want.

Importantly, being dispatched can be compatible with any other agreements the FRMP might have. For example, if a FRMP is providing services to networks it could reflect this in its bids. This way AEMO knows the intentions of these resources and can factor these in.

Through the bidding and dispatch process, AEMO does not control or direct how much a participant offers in terms of amounts of energy or prices. Once a participant is dispatched they must do what they said they would do. AEMO can then operate the market, knowing these intentions will be delivered.

Source: AEMC

3.2.1 Dispatch mode is the best way to integrate unscheduled price-responsive resources in the NEM

Several stakeholders supported the introduction of dispatch mode as a step to drive full market access to VPPs.[44] Tesla noted that this reform would improve the revenue stack for retailers and aggregators and most importantly create a stronger customer value proposition to drive additional VPP uptake.[45] Reposit considered that there would be no reason for capacity from price-responsive resources to be treated any differently from any other resource.[46]

These stakeholders noted that this framework is needed to allow these resources to provide regulation FCAS or be eligible for Capacity Investment Scheme (CIS) tenders.

Some stakeholders disagreed with integrating unscheduled price-responsive resources into dispatch, particularly CER. This was either due to:

- the costs to participate that may reduce the viability of CER products and services,[47] or
- unscheduled price-responsive resources behaving differently from other scheduled generators and not suiting the design of the central dispatch processes.[48]

We agree to an extent with these submissions. We note that not all resources will be able to or want to participate in dispatch mode. In particular, participating in dispatch is likely to only be suitable for FRMPs with forecastable and controllable resources. We do not consider that this framework should or would be able to accommodate all types of currently unscheduled price-responsive resources. Our draft rule establishes a monitoring and reporting framework (see section 3.4 for further details) for resources that won't participate in dispatch.

The Commission considers that a framework should be implemented to allow aggregated predictable and controllable price-responsive resources to participate in the NEM, like large scale resources can.

There were no other viable approaches suggested

Few alternatives to dispatch mode were suggested by stakeholders in our consultation. Enel X and the AEC questioned if amendments to other current categories, such as the Wholesale Demand Response Mechanism (WDRM) or SRA, could be used to integrate unscheduled price-responsive resources.[49]

44 Tesla, submission to the consultation paper, p. 2.
45 Tesla, submission to the consultation paper, p. 2.
46 Reposit, submission to the consultation paper, p. 1.
47 Origin, submission to the consultation paper, p. 4.
48 SwitchDin, submission to the consultation paper, p. 1.
49 Submissions to the consultation paper, Enel X, p. 6, AEC, p. 5.

In regard to the WDRM, the Commission does not consider this is feasible. WDRM is a bespoke mechanism for demand response coordinated by a party that is not the FRMP at the connection point to be included in central dispatch. It is designed to overcome issues of access and exposure to spot prices for parties that are not retailers. By definition, this restricts its application to parties that are not inherently incentivised to respond to spot prices because they are not exposed to spot prices. This is in contrast to dispatch mode which is designed to allow all the demand response coordinated and provided by those that are exposed and incentivised to respond to the spot price, to participate in dispatch.

Additionally, because the WDRM applies to non-FRMPs, it requires the use of baselines. Baselines are not suited to the wide range of consumers and resources which we are seeking to facilitate participating in dispatch. For example, it is very difficult to set appropriate baselines for aggregated residential customers or for mid size batteries.

We note that some of Enel X's suggestions to improve the WDRM can be made through the rules while others require AEMO guideline changes. The Commission will complete a review of the WDRM by 24 October 2025 and will consider Enel-X's proposed improvements to the WDRM in this review.[50] AEMO may investigate changes to its WDRM guidelines and processes separately.

The AEC suggested that amendments to existing categories (for example, SRAs) could address the problems identified. The Commission agrees with this approach. However, the Commission considers that this is what the draft rule does. The design of dispatch mode as set out in this draft rule is not introducing a new mechanism or participant classification. Instead, dispatch mode allows existing registered participants to nominate their connection points as part of a VSR to allow them to be included in dispatch. The types of registered participants who could do this includes SRAs, market customers (retailers), generators and (more broadly) Integrated Resource Providers (IRPs).

The Commission considers that incentives to participate in scheduling and dispatch need to be considered, rather than expanding the mandatory thresholds. The most significant feedback on AEMO's proposed dispatch mode was the lack of incentives to participate.[51] We agree that incentives are important to drive participation and market design should reward participants for the benefits that they provide the system. Section 3.3 provides further information on our analysis of the incentives to participate.

3.2.2 Stakeholders supported a flexible approach that minimises participation barriers and uncertainty

Stakeholders supported a low cost approach to integrate unscheduled price-responsive resources.[52] Key issues raised in submissions to the consultation paper regarding costs included:

- the costs of participating in dispatch mode may be a significant barrier, such as the costs required to set up appropriate remote communication, accuracy and data requirements[53]
- the proposed compliance arrangements may act as a potential barrier to participation with changes needed to strike a balance between encouraging participation and accurate participation.[54]

50 AEMC, AEMC's review of the Wholesale Demand Mechanism, 30 May 2024

51 AEMC, TWG meeting #1, 21 February 2024; AEMC, TWG meeting #4, 12 March 2024 .

52 EnergyAustralia, submission to the consultation paper, p. 3.

53 Submissions to the consultation paper, Mondo, p. 6, Evergen, p. 6, TESLA, pp. 10-11, sonnen, p. 6.

54 Submissions to the consultation paper, EUAA, p. 7, Mondo, p. 8, Red Lumo, p. 3.

In addition, through our TWG meetings and bilateral stakeholder engagement the Commission heard that:[55]

- certainty through the rules and requirements is beneficial in order to secure long-term investment decisions
- the variety of consumer contracts and different resources creates a range of complexities in how resources are set up and could participate.

We share the views that participating in dispatch would be complex due to FRMPs' varying levels of control and the additional factors that must be considered in providing bids and meeting dispatch targets. The draft rule addresses these concerns in a number of ways:

- Additional flexibility is being provided to participants to choose to opt-out for short periods and hibernate for longer periods.
- The ability to participate at either connection points or secondary settlement points, and as either an individual resource or an aggregated resource.
- We have provided AEMO with factors, such as minimising the costs to participate, that it must have regard for in developing guidelines and requirements.

These features will reduce the costs and time to implement and participate in dispatch mode. Further details on how participants would be able to nominate as a VSR can be found in appendix A.

The draft rules do not need to provide for any additional consumer protections

Mondo, EUAA, Fortescue, EQL and Energy locals raised that we should consider the impact on consumers from FRMPs participating in dispatch with their resources.[56] The Commission notes that FRMPs are already engaging, and will continue to engage, with customers to use their CER to respond to spot prices. This rule change does not change the nature of this engagement, or the need for appropriate consumer protections governing this engagement.

We expect that a FRMP participating in dispatch would do so in a way that aligns with their and their customer's preferences. By this, we expect them to bid in at price volumes that they have agreed upon in the contracts that they have. We do not expect a customer to see any noticeable difference between being part of a VPP that is participating in dispatch and one that is not. There is no requirement to change their behaviour or cede control of their assets in any shape or form. A VSRP would in aggregate provide bids that reflect how responsive its customers are.

Importantly, residential and small consumers' energy usage that is not coordinated by FRMPs are not the focus of this draft rule change. For example, a consumer self-consuming from their battery would not be required to do anything differently as a result of this rule change.

While the Commission considers that this draft rule does not alter the nature of relationships between FRMPs and consumers with CER, we do note that issues have been identified with these current relationships and these should be addressed. The ESB recommended that the National Energy Customer Framework (NECF) is updated to ensure that consumers can benefit from this type of innovation whilst also being protected from negative impacts.[57]This is part of ongoing consideration by the CER Taskforce.[58] In the meantime, existing consumer protections under the NECF and Australian Consumer Law will continue to apply (noting that the *Unlocking CER Benefits*

55 AEMC, TWG meeting #3, 4 March 2024.

56 Submissions to consultation paper, Mondo, p. 7, EUAA, p. 6, Fortescue, p. 4, EQL, p. 4, and Energy Locals, p. 6.

57 ESB, Consumer Energy Resources and the transformation of the NEM, 2024.

58 Department of Climate Change, Energy, the Environment and Water, National Consumer Energy Resources Roadmap, Powering Decarbonised Homes and Communities, July 2024.

through flexible trading rule change would extend key protections in the NERR to secondary settlement points).

3.3 We are creating additional incentives to drive participation

Our draft rule provides for two new incentives:

- a time-limited incentive scheme to drive participation in the mechanism in its early years
- excluding participants from RERT cost recovery.

This section outlines:

- participants would derive some direct benefits from participating section 3.3.1
- stakeholders highlighted the need for additional incentives section 3.3.2
- the draft rule provides additional incentives section 3.3.3
- we do not propose to make participation mandatory section 3.3.4
- external market incentives could drive participation and benefits section 3.3.5
- in the future, the AEMC will consider how being scheduled could be made more desirable for participants, section 3.3.6.

3.3.1 Participants would derive some direct benefits from participating in dispatch

There are some direct benefits that participation results in. By participating in our new framework:

- AEMO's NEM Dispatch Engine (NEMDE) will co-optimise VSRP bids for energy and for FCAS in the same way as it does for other scheduled resources. This will maximise the bids of VSRPs in FCAS and the wholesale market by enabling their optimal dispatch.
- VSRs will be eligible to participate in regulation FCAS markets. This aligns VSRs with other scheduled resources currently eligible to provide regulation FCAS and opens a new opportunity for VSRPs to participate in the NEM. Through the TWG and bilateral meetings with prospective participants, we heard that the revenue stream from providing regulation FCAS is a material incentive.[59]
- VSRPs will be eligible for frequency performance payments (FPPs). This aligns VSRPs with other scheduled resource providers that, when the FPP rule takes effect, will be subject to FPPs.

Amendments to the rules are not required to provide these benefits. A VSRP would receive them automatically if it participates in dispatch and classifies the relevant resource as an ancillary service unit. However, there are different technical requirements associated with each that a participant would need to meet. For example, accessing regulation FCAS markets would necessitate uplift on the participant's end to meet relevant technical requirements, see appendix B.

3.3.2 TWG and submissions highlighted the need for additional incentives

Stakeholders considered that a key element of participation in dispatch mode is getting the incentives to participate right. Many stakeholders considered that market revenues (through access to other markets such as regulation FCAS) would not be sufficient to drive participation.[60] This is because FRMPs are already exposed to the spot price and individually benefit from

59 Submissions to the consultation paper, CEC, p. 2, Enel, X, p. 5, Evergen, p. 8, Shell, pp. 3-4, sonnen, p. 7, Tesla, p. 11, AEMC, TWG Minutes #4, 12 March 2024.

60 Fortescue, submission to the consultation paper, p. 3.

reduced consumption during high price periods, whether or not they are scheduled. Several stakeholders identified that direct payments would be required to participate in AEMO's proposed visibility mode.[61]

3.3.3 The draft rule provides additional participation incentives

Our draft determination is that the direct benefits outlined above are not sufficient to drive participation in dispatch at levels that would benefit the market. Additional incentives will be required, and therefore the draft rule introduces two additional incentives.

A time-limited payment mechanism for participating in dispatch mode

The draft rule includes a time-limited incentive scheme to drive participation in the mechanism in its early years. It does this by allowing AEMO to conduct tenders to pay participants to enter dispatch mode in the first five years of the mechanism. To ensure that consumers benefit from participation, the payments are capped at a proportion of the estimated benefits of participation. Furthermore, to limit the extent of the total impact on customers the draft rule also caps the overall payments under the framework at $50m.

The Commission considers that this incentive scheme is necessary because of the combination of these factors:

- the majority of the benefits of participation in dispatch accrue to all consumers, not the participant
- there are well recognised natural disincentives to being scheduled in the NEM (for example additional data and communication requirements)
- the mechanism is new and therefore there are likely to be positive effects on later participation from early entry.

The Commission considers that while necessary, this incentive framework is not a natural fit within the NER and is therefore not our ideal approach. Between the draft and final determination, the Commission will be working with ARENA, the Commonwealth and jurisdictional governments regarding alternatives to having the incentive scheme in the NER. An external incentive mechanism is our first preference and if this eventuates we would remove the AEMO tendering mechanism from the final rule.

See appendix B.3 for details.

VSRPs are excluded from RERT cost recovery

The Commission's draft determination is to amend the RERT rules to exclude a VSRP's adjusted consumed energy from RERT cost recovery calculation. In practice this means that during periods where RERT is enabled and the VSRP is a net consumer, they will not be liable for RERT cost recovery payments. This change is consistent with the approach to exclude the energy consumed by BDUs from RERT payment calculations, introduced in the IESS rule change.

See appendix B.2 for details.

3.3.4 We do not propose to make participation mandatory

A few stakeholders considered that participation should be mandatory where aggregated resources are above a certain threshold (for example, 30MWs similar to other generation).[62] These

61 Submissions to the consultation paper, SwitchDin, p. 4, Mondo, p. 5, and sonnen, p. 4.

62 Submissions to the consultation paper, Stanwell, p. 3, Reposit, p. 1.

stakeholders noted that making participation mandatory would avoid the need to provide additional incentives. Furthermore, Stanwell noted that FRMPs have the technical expertise and systems in place to participate effectively.[63]

However, other stakeholders did not support making participation mandatory as it could hinder the VPP market development.[64]

Our draft rule does not make participation in dispatch mode mandatory. The Commission considers that for scenarios where the FRMP is contracting with small customers to orchestrate their devices (such as VPPs), it is not viable or desirable to mandate participation. FRMPs do not own the individual assets and have no right to control them without consumers' consent. Mandatory participation would require FRMPs to have significant control over the resources that underpin their participation in dispatch. This would mean FRMPs would need to have contracts with consumers providing them with control of consumers' CER. To allow this, the rules would need to empower FRMPs to gain such control. The Commission considers that this is highly undesirable and likely infeasible.

A more feasible solution would be to mandate participation of price-responsive large loads or mid-sized generators (1-30MW) and storage (1-5MW). We note this would be similar to previous proposals to lower the scheduling threshold. However, it would require these mid-sized resources to participate in dispatch mode rather than the existing scheduling categories. The Commission does see some merit in this option. We note that it may need to be looked at closely in the future if the breadth and volume of these unscheduled price-responsive resources start to have significant impacts on the efficiency of the NEM. For example, if we see very large price-responsive loads like electrolysers connect to the NEM and not participate in dispatch mode. Or if a large volume of aggregated mid-sized batteries connects and does not participate in dispatch mode.

While mandating these types of resources to participate would have benefits, we note that it would come with challenges. These have been explored in previous rule changes by the Commission assessing the scheduling threshold and concluded:[65]

- It is unlikely to substantially increase the resources that are scheduled, as it can be avoided. There are instances of participants avoiding the existing requirements by ensuring assets are under the relevant threshold. For example, there are a number of batteries with a capacity of 4.9MW, and 29MW generators. Reducing the threshold would likely be challenging and ineffective as participants would seek to avoid the new thresholds with assets below the new thresholds.
- Mandates are a blunt tool that force all participants above the threshold, regardless of cost, to participate.
- It would require consideration of grandfathering for existing assets.

In addition, we would still be faced with needing to incentivise aggregated CER to participate in dispatch. Therefore, at this time, our preference is to try to develop incentives for participation in dispatch rather than mandates.

63 Stanwell, submission to the consultation paper, p. 3.

64 Submissions to the consultation paper, Simply Energy, p. 2, Tesla, p. 5.

65 AEMC, Non-scheduled generation and load in central dispatch rule change, 2017.

3.3.5 External market incentives could drive participation and benefits

Stakeholders made a number of suggestions for how incentives to participate could be enhanced. This includes engaging with Commonwealth and state governments to consider different policy incentives that can work in tandem with market incentives.[66]

Eligibility for Capacity Investment Scheme

Stakeholders noted that the CIS is providing a safety net for investment in clean dispatchable capacity.[67] Unscheduled price-responsive resources, such as VPPs, are currently excluded from the scheme as they are not dispatched. Participating as a VSRP, in this framework, would incorporate these resources into dispatch, and demonstrate that they have the required technical capabilities.

The Commission supports FRMPs participating as VSRPs, being eligible for CIS funding. This would serve as an additional incentive to participate in dispatch and recognise the capabilities of these resources.

ARENA trial funding could be appropriate

There are a number of features of this new framework that potentially make a trial funded by an entity such as ARENA a good initial first step to stimulate participation. This includes:

- the infancy of unscheduled price-responsive resources interacting with the wholesale market
- a number of technical capabilities that need to be developed. For example the use of aggregated resources at the distribution level to provide regulation FCAS. As this is novel it could create risk and uncertainty for FRMPs on whether to participate and if they can benefit from these additional markets, potentially limiting participation.
- key barriers such as set up costs and operational forecasting (which could be novel for some participants)
- the potential to integrate lower emitting resources and to help transition to a net zero system
- sizeable benefits to Australian energy consumers.

The Commission is aware that previous trials have been undertaken to demonstrate new energy frameworks, for example the 2017 AEMO and ARENA proof of concept trial for RERT.[68] The Commission is keen to progress consideration of trials to demonstrate that a range of resources and providers could participate in dispatch and improve FRMP readiness.

3.3.6 In future the AEMC will consider how being scheduled could be made more desirable for participants

There are a number of reforms and potential future changes expected in the NEM. The Commission considers that long term participation incentives are also required. These are best provided through market and network access considerations of future reforms.

The Commission considers a key principle in this work is that scheduled participants should have access to the network commensurate with the benefits they are providing the broader system. Crucially, this needs to result in the opposite outcome to our current regulations at the transmission system where unscheduled generators have preference over scheduled and semi-scheduled generators. In particular, consideration could be given to:

66 Submissions to the consultation paper, Tesla, p. 11, Shell, p. 4, Evergen, pp. 8-9.

67 The Commonwealth Department of Climate Change, Energy, the Environment and Water (DCCEEW), Capacity Investment Scheme, accessed June 2024

68 ARENA, Demand response RERT Trial, 2019.

- Greater market access for scheduled resources. It is possible in a future wholesale market design that some form of dispatchability payments or an enduring government scheme is introduced to support formal participation in the market, which would require being scheduled as a condition of payment. Participants in dispatch should have access to markets for the full suite of services they are capable of providing. In the future, this may include access to new system security markets or access to capacity payments.
- Greater network access for scheduled resources. Reforms on distribution operating envelopes and flexible export limits are currently being explored. It is possible that being scheduled will have some benefits in these reforms.

As the AEMC considers future rule changes, we will give consideration to how any reforms or amendments could be made more preferential to scheduled participants. These participants have demonstrated a technical capability to be coordinated with the rest of the system. Where there are rule changes regarding distribution network limits for example, we will consider how preferential access could be provided to the resources in dispatch mode.

3.4 We are establishing an AER and AEMO monitoring and reporting framework

The majority of unscheduled price-responsive resources are unlikely to participate in dispatch mode. However, they will create challenges for AEMO's demand forecasting in the NEM and this may have large consequences for efficient market operation.

This section sets out how:

- our draft rule introduces a monitoring and reporting framework for AEMO and the Australian Energy Regulator (AER) to assess the impact of price-responsiveness (section 3.4.1)
- we considered AEMO's visibility mode proposal but consider it would be high cost and not enable the efficiency benefits due to the information not being used in central dispatch (section 3.4.2)
- we considered alternatives raised in submissions and through further work (section 3.4.4).

3.4.1 The draft rule would create a reporting obligation for AEMO and the AER on unscheduled price-responsive resources

Our draft rules introduces a monitoring and reporting framework for AEMO and the AER.

This reporting framework will provide more transparency on the materiality of deviations of actual demand from forecasts and the inefficiencies that these deviations cause. This transparency will facilitate analysis of AEMO's operational demand forecasting methods and whether changes can reduce such inefficiencies, should they materialise. Collectively, this reporting and transparency framework will help us understand how unscheduled price-responsive resources are changing and their impact on market outcomes. It will also provide evidence which the AEMC will consider when determining whether to introduce structural changes to demand forecasting or a visibility market model in the future.

Specifically, the draft rule would introduce:

- Monitoring and reporting by AEMO to:
  - identify the presence and issues created by increased unscheduled price-responsive resources

  - publish its methods and assumptions for regional demand forecasting in operational timeframes and the measures it takes to improve it to account for unscheduled price-responsive resources.
- Monitoring and reporting by the AER to assess the efficiency implications and costs associated with increased unscheduled price-responsive resources. To the extent that AEMO can account for price-responsive resources through forecasting or participation in dispatch mode, this would reduce the efficiency implications and costs associated with increased price-responsive resources.

This policy was informed by stakeholder feedback through the TWG, and submissions from CS Energy and the EUAA.[69]

This new reporting framework would complement and build on the existing reporting requirements for AEMO and the AER which are set out below.

- AEMO's current reporting requirements:
  - It has a range of reporting requirements concerning forecast accuracy and whether/how it accounts for unscheduled price-responsive resources. However, these are limited to the planning timeframe and focus on reliability and the extent to which forecast errors have contributed to AEMO's planning (ESOO) or operations (such as declaring a lack of reserve condition).
  - It is already required to publish how it considers demand-side participation information in forecasts in general terms.[70] However, the focus of this new reporting requirement is on unscheduled price-responsive resources, which would be a subset of this analysis.
  - It is required to prepare pre-dispatch and dispatch forecasts. However, the methods within these processes are opaque and AEMO does not provide much detail in its operating procedures. For example, AEMO's load forecasting procedure sets out one paragraph of information on how it produces load forecasting in the dispatch period.[71]
- The AER has a principles-based reporting framework in the National Electricity Law (NEL) and NER to consider effective competition and market efficiency in relevant energy markets. The draft rule creates a new requirement for the AER to consider the impact of unscheduled price-responsive resources on market efficiency, as part of its market monitoring functions under NEL s 18C.

3.4.2 We considered AEMO's proposed visibility mode but it would not be used in dispatch

AEMO's rule change request included a 'visibility mode' that was designed to enable FRMPs to directly bid their demand-response into the market to improve situational awareness. The proposal included the following key features:

- Participants could voluntarily register National Meter Identifiers (NMIs) in a light scheduling unit (LSU). Participating FRMPs would be required to provide indicative bids for the forecast of generation and consumption.
- The framework would allow for flexible participation, rather than the ongoing active operation requirements in place for other market participants.
- The indicative bids would not be included in AEMO demand forecasting or dispatch. They would be used to improve AEMO situational awareness.

69 Submissions to the consultation paper, CS Energy, p. 3, EUAA, p. 3.

70 NER rule 3.7D.

71 AEMO, Load Forecasting procedure, May 2023, p. 8.

Informed by stakeholder feedback and further analysis, the Commission considered that AEMO's visibility proposal had material weaknesses that would be difficult to overcome. These include:

- AEMO's proposal would not incorporate indicative bids into dispatch. This would mean that the IES 'size of the prize' modelled benefits of improved dispatch outcomes or reduced FCAS costs would not occur.
- AEMO's proposal requires NMIs to be registered within a LSU to participate in the visibility mode. This requirement creates a high barrier to entry because of the real-time metering and telemetry requirements and would limit the resources that can participate. We also considered the lack of integration in central dispatch would mean AEMO's visibility mode would not be likely to meet the national electricity objective.

3.4.3 We considered an alternative visibility market model with significant upside

The Commission considered issues raised by stakeholders and the deficiencies with AEMO's visibility mode. We explored an alternative visibility market model prepared by Creative Energy Consulting that would incorporate bids directly into AEMO's forecasting and dispatch.[72] While this model has significant benefits and would incorporate unscheduled price-responsive resources into dispatch, it has high costs, and we consider it is not yet warranted.

Under the alternative visibility market model, participants would bid unscheduled price-responsive resources and these bids would be used by AEMO in central dispatch to form a price-elastic demand forecast. The Commission considers that the visibility market model has considerable merit and analysed it in detail. This model has some key design differences relative to AEMO's visibility mode that we consider would materially increase benefits and lower costs for market participants:

- quasi-bids would be submitted for unscheduled price-responsive resources by FRMPs on a regional aggregate basis rather than through a LSU
- the quasi-bids would be used by AEMO in central dispatch, thus improving the accuracy of demand, dispatch instructions and price formation
- FPPs would be used to drive incentives for participants to provide accurate quasi-bids.

The Commission considers that this visibility market model would be likely to deliver the following benefits and could potentially contribute to the achievement of the national electricity objective:

- It would efficiently allocate risks to those best-placed to manage them. By transferring responsibility to market participants (e.g. retailers) for forecasting the price-responsiveness of their customers, risks are efficiently allocated. Retailers purchase energy on behalf of customers in the spot market and on sell it to them. Generally, they possess the best information about the price-responsiveness of their customers because they have the retail contract that passes through prices and invest significant resources to know how much energy they will be purchasing at different times and price levels.
- It would include incentives that would appropriately reward the provision of accurate information. With retailers undertaking forecasts, financial incentives could be created for providing accurate quasi-bids through the use of frequency performance payments.
- It would reduce market inefficiencies associated with unscheduled price-responsive resources. By AEMO incorporating quasi-bids into dispatch, it would have a more accurate view of demand, thus improving price formation, dispatch instructions, and reduce the reliance on RERT.

72 Creative Energy Consulting prepare for the AEMC, *A Market Design to integrate Demand Response into NEM Pricing and Dispatch*, 25 July 2024.

However, after detailed design discussions with AEMO and our TWG, the Commission concluded that the visibility market model is likely to have high cost and complexity for AEMO to implement and maintain, and the solution is not yet warranted. The Commission's analysis and relevant stakeholder feedback considered in reaching this conclusion is set out below:

- While the volume of unscheduled price-responsive resources is growing, it has not yet reached a point where it is materially challenging AEMO's demand forecasting and it would come with material costs to produce the necessary forecasts. We consider that the monitoring and reporting framework will place us in a good position to determine when AEMO's demand forecasting is materially challenged, and if these challenges can be addressed adequately by changes to AEMO's demand forecasting methods, and therefore whether a move to retailer-led forecasting of price-responsiveness is warranted.
- Stakeholders, through the TWG, raised concerns with implementing a large regulatory solution without evidence that AEMO has tried and not succeeded to improve its forecasting. The Commission received clear and repeated feedback from submissions and through the TWG that a large regulatory solution such as the alternative visibility model is not warranted yet. In particular, TWG members considered incremental changes such as improvements to AEMO forecasting should be explored in lieu of a significant market reform particularly since unscheduled price-responsive resources haven't yet materially influenced inefficient market outcomes.

3.4.4 We considered other ways to improve visibility and transparency of unscheduled price-responsive resources

In response to the consultation paper, stakeholder submissions raised alternative approaches to address the visibility of unscheduled price-responsive resources. These included introducing a reporting framework to assess the accuracy of AEMO's demand forecasts, and improve information collection processes to make them fit for purpose. Each of these are discussed below.

Improve information collection processes to make them fit for purpose

Several submissions outlined that AEMO currently has a range of methods, such as the DER register and demand-side participation information portal (DSPIP), to collect information about unscheduled price-responsive resources. These stakeholders suggested changes to make the existing arrangements fit for purpose. These views were reiterated in TWGs and individual stakeholder discussions.[73] In particular:

- **DER register**: static register, updated for new or amended installations of battery storage and rooftop solar devices (potentially with EV chargers in the future) at residential or business locations. It shows the number and installed capacity by region, to a post-code level but not the level of control or operation of those devices.
- **DSPIP**: collected annually, the DSPIP contains information about the characteristics of DSP contracts from registered participants. The information is used to inform reliability modelling (ESOO, Energy Adequacy Assessment Projection (EAAP), Medium Term projected assessment of system adequacy (MT PASA) and the ISP).

The Commission considers that these mechanisms deliver extensive information to AEMO. It is unclear if this information and arrangements have been used to their fullest. Therefore, the

73 Submissions to the consultation paper, Clean Energy Council, p. 3, Australian Energy Council, p. 4, FlowPower, p. 5, Enel X, p. 4, EnergyAustralia, p. 3, Origin, p. 3.

Commission considers that more information and transparency is needed, drawing from current information sources, before increasing the regulatory burden on market participants.

Assess the accuracy of AEMO's demand forecasts and provide transparency on the materiality of the inefficiencies

Stakeholders considered that there is not sufficient transparency on AEMO's operational demand forecast errors to appropriately qualify whether a visibility mode is required. CS Energy considered that AEMO has not reasonably justified why it requires more dynamic visibility. CS Energy proposed that more transparency is needed on AEMO's demand forecast accuracy in operational forecasts and non-regulatory options for improving forecasts.[74] EUAA echoed this sentiment and proposed a regular reporting requirement for AEMO to publish forecast accuracy reports (monthly or quarterly). EUAA proposed that this report would cover all of AEMO's forecasting requirements and compare against actual market real time 5 minute dispatch outcomes, including a process for improving forecasting where an issue is identified in the report. EUAA also proposed that this report should be prepared by an independent market body such as the AER or the AEMC to ensure impartiality.[75]

The Commission considers that introducing a monitoring and reporting framework is a lower-cost and proportionate response that better serves the immediate needs of the market. Furthermore, we consider that AEMO's work to improve its forecasting to account for unscheduled price-responsive resources is worth exploring as improvements could reduce the problem and the need for a higher-cost regulatory response.

3.5 Transitional provisions support the timely introduction of our draft rule

After we make the final rule for this rule change, a suite of procedures and guideline changes will need to be undertaken by both AEMO and AER. These procedures and guidelines will specify operational and technical requirements, as well as transitional arrangements, to ensure that the rule changes would operate as intended.

AEMO and the AER will be required to undertake consultation processes in relation to some of these procedures and guidelines. Our overriding approach has been to implement dispatch mode, the incentive mechanism and reporting requirements at the earliest possible dates within AEMO and the AER's capabilities and resources. This results in varying implementation time frames for the mechanisms:

- **Dispatch mode** — AEMO must develop and publish its VSR guidelines by 31 December 2025, with a commencement date of 5 November 2026 for VSRPs to start participating in dispatch.
- **Incentive mechanism** — AEMO must release its incentive procedures by 5 November 2026, with the five-year incentive period running from 2027-2031.
- **Monitoring and reporting** — AEMO and the AER must release their reporting guidelines by 31 December 2025; AEMO must publish its first quarterly report by 1 April 2026 and its first annual report by 30 September 2026, with the AER publishing its first report by 31 December 2026.

Further details on the transitional arrangements can be found at: appendix A.6, appendix B.3.3 and appendix C.3.

74 CS Energy, submission to the consultation paper, p. 3.

75 EUAA, submission to the consultation paper, p. 3.

4 The draft rule would contribute to the national electricity objective

This Chapter sets out how our draft rule promotes the National Electricity Objective (NEO). It highlights that our draft rule primarily increases the efficient operation of the wholesale market. This is in the long term interests of consumers of electricity with respect to the price, the security and reliability of the supply, and the achievement of emissions reduction targets.

This chapter describes:

- the NEO test that the Commission must apply to make a draft rule, (section 4.1)
- how our draft rule is likely to contribute to the long-term interests of consumers, (section 4.2).

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

The Commission can only make a rule if it is satisfied that the rule will or is likely to contribute to the achievement of the relevant energy objectives.[76] For this rule change project, we have made a draft electricity rule so the relevant energy objective is the NEO.

The NEO is:[77]

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

The targets statement, available on the AEMC website, lists the emissions reduction targets to be considered, as a minimum, in having regard to the NEO.[78]

There are also a number of relevant legal requirements under the NEL and National Energy Retail Law (NERL) for the Commission to make a draft rule determination. These are set out in appendix E.

4.1.1 We have considered whether to make a more preferable draft rule

We have also considered whether to make a more preferable draft rule. The Commission may make a rule that is different, including materially different, to a proposed rule (a more preferable rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule is likely to better contribute to the achievement of the NEO.[79]

For this rule change, the Commission has made a more preferable draft electricity rule. The reasons are set out in section 4.2 below.

76 Section 88(1) of the NEL and 236(1) of the National Energy Retail Law (NERL).

77 Section 7 of the NEL.

78 Section 32A(5) of the NEL.

79 Section 91A of the NEL.

4.1.2 We have considered whether consequential changes to the NERR would be required

In assessing the rule change request and developing the draft electricity rule, we have considered whether any consequential changes to the NERR would be required, such that a draft retail rule should be made. To make a draft retail rule, the Commission would need to be satisfied that the rule will or is likely to contribute to the achievement of the National Energy Retail Objective (NERO).[80]

The Commission's draft determination is that no consequential amendments to the National Energy Retail Rule (NERR) are required, and therefore we have not made a draft retail rule or applied the NERO. We expect that a FRMP participating in dispatch would do so in a way that aligns with their and their customer's preferences. By this, we expect them to bid in at price volumes that they have agreed upon in the contracts that they have. We do not expect a customer to see any noticeable difference between being part of a VPP that is participating in dispatch and one that is not. There is no requirement to change their behaviour or cede control of their assets in any shape or form. A VSRP would in aggregate provide bids that reflect how responsive its customers are.

4.2 Our more preferable draft rule would contribute to the NEO

The Commission has identified the following five criteria to assess whether the proposed rule change, no change, or other viable rule-based options are likely to better contribute to the NEO:

1. Security and reliability — would greater visibility and dispatchability of price-responsive resources promote a secure and reliable electricity system at the lowest cost through more accurate forecasting and operation?
2. Concepts of efficiency — to what extent will increased visibility and integration of price-responsive resources in the scheduling process lead to productive, allocative and dynamic efficiency?
3. Decarbonisation — would the solution efficiently contribute to the achievement of government targets for reducing, or that are likely to reduce, Australia's greenhouse gas emissions?
4. Implementation costs — what will be the costs to participants, consumers and AEMO of implementing any solution? What will the costs be to participants, consumers and AEMO of complying with any solution over time?
5. Flexibility — would the solution be future-proof, resilient and able to accommodate market, technological, policy and other changes?

To support our decision-making, the Commission has undertaken a regulatory impact analysis to evaluate the impacts of the draft rule and other policy options against the assessment criteria. The rest of this Chapter explains why the Commission's more preferable draft rule is most likely to promote the long-term interest of consumers, compared to the proposed rule, no change, or other viable rule-based options.

4.2.1 Creating a new framework for participation in dispatch would contribute to the NEO

Dispatch mode is a material regulatory change in the NEM. Our regulatory impact analysis has therefore included formal market modelling to quantify the costs and benefits of the change. The modelling focuses on the types of impacts within the scope of the NEO, including the cost of operating the power system reliably and securely, dynamic and productive efficiency, and the extent to which it impacts decarbonisation.

80 Section 236(1) of the NERL.

The Commission engaged IES to adapt its size of the prize modelling to include projected uptake rates of dispatch mode and then use the same methodology as described in Chapter 2 to estimate its benefits. There is material uncertainty regarding the uptake of dispatch mode and we therefore had IES take a probabilistic approach to modelling the benefits. IES modelled a high, medium and low participation sensitivities and then gave them weights based on the likelihood of them eventuating, see (Box 4) for an explanation of this. This provides a weighted benefit which the Commission primarily considers for its NEO assessment. These are set out in Table 4.1. AEMO also provided an initial cost estimate of its costs to implement the framework of $29m.

Table 4.1: IES benefits by different participation scenarios

Benefit category	Low participation (million AUD)	Medium participation (million AUD)	High participation (million AUD)	Weighted probability (million AUD)
System security - FCAS benefits	220	403	617	411
Reliability - RERT benefits	100	100	100	100
Productive efficiency - Generation benefits	63	120	180	121
Emissions benefits	140	199	274	203
Total	**523**	**821**	**1,170**	**834**

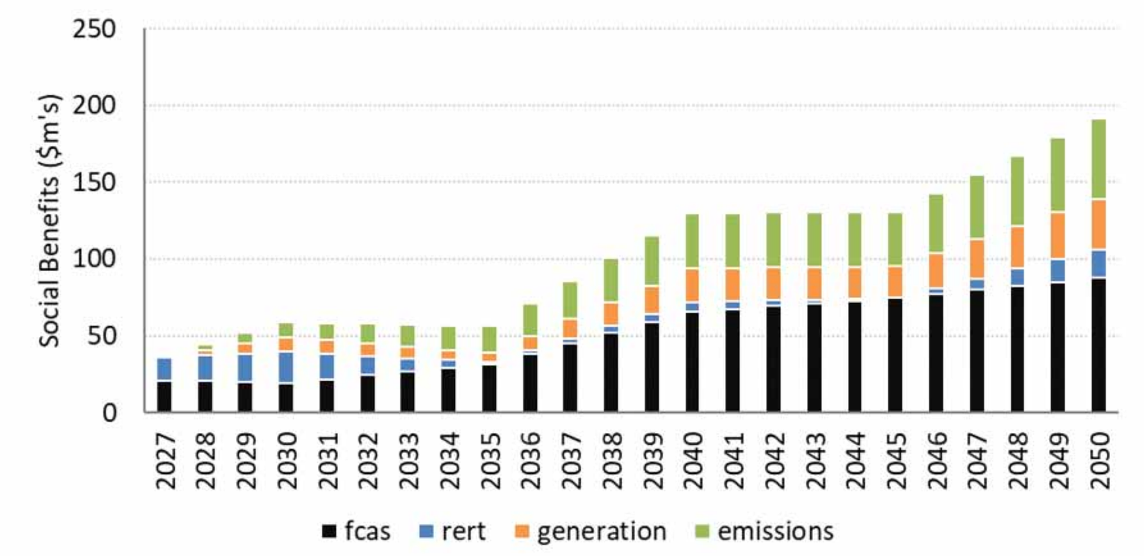
Source: IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, sensitivity modelling results, 8 July 2024

The Commission considers that these estimates provide a strong case that dispatch mode meets the NEO and should be implemented. Our probabilistic assessment is a net benefit of $805m. Furthermore, even in the low uptake scenario modelled by IES the net benefits of dispatch mode are $494m, an order of magnitude greater than the costs.[81]

Another important feature of the IES modelling is the quantification of when the benefits of dispatch mode occur. These are plotted in Figure 4.1. Most importantly, while the benefits grow over time as the quantity of otherwise unscheduled price-responsive resources in the NEM increases, the benefits are already material by 2030. This provides strong justification for implementing the solution as soon as possible.

81 IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, sensitivity modelling results, 8 July 2024.

Figure 4.1: IES probabilistic benefits from implementing dispatch mode



Source: IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, sensitivity modelling results, 8 July 2024

Note: IES modelled snapshot years every 5 years, results have been interpolated for the remaining years.

Promotes security and reliability of the power system at the lowest possible cost

Dispatch mode promotes the security and reliability of the power system by ensuring more accurate demand forecasting and efficient operation of the NEM. It primarily does this by creating a framework for more resources to participate in dispatch. By having more price-responsive resources scheduled, AEMO will not need to forecast these resources and therefore forecast accuracy is likely to improve. This promotes:

1. System security at the lowest cost by reducing the use of generation reserves to balance the market, such as FCAS. IES's modelling estimates these cost savings to be $411m (NPV) from 2027 to 2050.
2. Reliability at the lowest cost by reducing the need for RERT. IES's modelling estimates these cost savings to be $100m (NPV) from 2027 to 2050.

Improves efficiency of investment and operations

Dispatch mode results in substantial efficiency improvements though:

- Improving operational demand forecasting, which will reduce the inefficient dispatch of generators, storage and demand response, thereby reducing the costs of operating those resources (productive efficiency). IES estimates that the reduction in generation costs over 2027-2050 is $121m. IES demonstrates that this is primarily driven by dispatching less peaking generation at high price times.
- Allowing AEMO to better match supply and demand. This will reduce operational demand forecast errors, resulting in more efficient price setting. This results in lower energy prices and potentially less volatile prices, benefiting all energy consumers. IES modelling identified $8.73b NPV wealth transfer benefits from implementing dispatch mode. These benefits arise from reduced energy and FCAS prices. We have not included the lower energy and FCAS prices modelled by IES in our cost-benefit assessment. These are not true efficiency gains.

Rather, they are wealth transfers from generators to consumers, and therefore we do not include them.

- The magnitude of the higher revenues earned by generators in the absence of dispatch mode would likely result in additional market entry and this entry would come with a material cost (a dynamic efficiency). IES's scope of works for the Commission did not attempt to model the additional generation and storage entering the market. This entry would come at a cost. The Commission has therefore only taken this into account as a qualitative indication that the overall IES benefits are likely understated.

It is likely to contribute to achieving emissions reduction targets

Our draft rule efficiently contributes to achieving government targets for reducing Australia's greenhouse gas emissions by more efficient operation of the wholesale market. More accurate demand forecasting and efficient dispatch may reduce the use of emissions-intensive generation. This is because there is a close correlation between high marginal cost generators and high emissions generators (e.g. gas powered generators). As these high cost, high emissions generators are dispatched less often, or for shorter periods, emissions will also decrease with the introduction of dispatch mode, helping to meet jurisdictional emissions targets. Through our modelling, we have identified $203m in emissions savings from introducing dispatch mode, using the agreed value of emissions reductions.

Balances implementation cost and complexity against the benefits

The draft rule has been developed with the aim of minimising costs for market participants and AEMO while maximising benefits to the market.

Chapter 3 sets out how the draft rule heavily leverages and builds on previous reforms (for example IESS). This reduces likely implementation costs for AEMO and market participants. AEMO's rule change request estimated that implementing both visibility and dispatch modes (as proposed in its request) would have an upfront cost of $18.2m (+/- 40%) + 10.5m over the first 10 years.[82]

The final costs will be determined as AEMO assesses the implementation of the draft and final rule. However, given that dispatch mode is largely consistent with AEMO's proposal, we do not expect that these costs will vary significantly. These costs are recovered by AEMO through Market Participants and ultimately customers.

The draft rule is resilient and future proof

Dispatch mode is highly flexible and resilient to future market and technology changes. At its core, dispatch mode is a platform for aggregated small-scale resources to be completely integrated into market dispatch. It is flexible to a wide range of resources, technologies and business models, and therefore robust to changes to all of these factors over time.

Similarly, dispatch mode is resilient to future regulatory reforms. The basic functions of participants bidding the response of currently unscheduled price-responsive resources to different spot prices, and following these bids, is important under any future regulatory framework.

82 AEMO, Rule change request — Scheduled Lite Mechanism in the National Electricity Market, p. 40.

We will seek to enhance our NEO analysis for the final determination but it is unlikely to have a material effect on our assessment

The Commission notes that there are four areas which may change between draft and final, or that we may seek further information and analysis to quantify. These are:

1. Participation costs. There will be costs for participants that choose to use the mechanism. These need to be considered when weighing the overall benefits of the mechanism. However, given the large modelled benefits, and that these costs are only incurred for participants that use the mechanism, we do not consider there is a material risk that the costs would impact our overall NEO assessment.
2. Dynamic efficiency gains from avoiding additional large scale generation and storage. As described above, IES did not quantify the likely dynamic efficiency gains from dispatch mode. We may seek to have IES update its modelling to include these for the final determination.
3. Incentive payments. Under the draft incentive mechanism, there will be payments of up to $50m from consumers to dispatch mode participants. However, this is a wealth transfer from consumers to participants, not an efficiency loss, and therefore (similar to the FCAS and energy prices) we do not include this in our NEO assessment. Furthermore, we are seeking alternatives to the incentive mechanism for the final determination and therefore these may not be relevant.
4. Interaction with Unlocking CER benefits for flexible trending rule change. The IES modelling results set out above assume that the reforms in the *Unlocking CER benefits through flexible trading*draft rule are implemented. This makes it easier for FRMPs with a mix of flexible and passive resources to participate in dispatch mode. IES also models a scenario where that rule change does not go ahead. In summary, this results in likely lower uptake of dispatch mode and a consequential decrease in benefits of $47m (NPV).

In conducting our NEO assessment we have also considered the distributional impacts of introducing dispatch mode. In general, the reduction in total system costs in the long run from the efficiency gains described above is likely to lead to lower prices for all consumers. We do not consider it is possible or necessary to identify the specific groups of customers most likely to benefit. Similarly, generators and retailers will incur lower costs in providing consumers with a reliable supply of electricity, but it is challenging to identify the specific beneficiaries of these efficiencies.

Additional modelling considered a range of potential participation rates through our new framework

In February 2024 we released modelling by IES on the potential total benefit of integrating unscheduled price-responsive resources. This modelling was a ‘size of the prize’ exercise. Section 2.2.4 provides an explanation of this modelling. For this draft determination, we asked IES to undertake additional modelling to align with the policy direction for dispatch mode and include our best available estimates of uptake of dispatch mode.

Box 4: IES sensitivity modelling for different participation scenarios

There is material uncertainty regarding the uptake of dispatch mode and we therefore had IES take a probabilistic approach to modelling the benefits. IES models a high, medium and low participation scenario and then gives them weights based on the likelihood of them eventuating. This provides a weighted benefit which the Commission primarily considers for its NEO assessment.

This involved:

- modelling impacts of the rule from November 2026, to align with expected implementation date for the rule
- modelling 3 different participation rate sensitivities: low, medium and high, see further below
- updating the modelled value of emissions reductions to use the energy ministers' agreed interim values (NSW Treasury figures were used in the February paper as the energy ministers had not released theirs yet).

In addition, we asked IES to:

- Determine the probabilistic NPV from dispatch mode based on different weights for the likelihood of the different participation scenarios. We provided IES with weights based on the likelihood of the scenarios eventuating. In addition, we provided different weightings for scenarios with and without the *Unlocking CER benefits through flexible trading* rule change. This rule change is expected to enable greater participation in dispatch, increasing the likelihood of the medium and high scenarios. Without the rule change the low and medium participation scenarios are more likely.
- Identify the relationship between participation and benefits.

We wanted IES to test a range of sensitivities:

- Low participation scenario — This assumes no additional incentives are provided to participants beyond access to existing markets such as regulation FCAS. Regulation FCAS is assumed to drive aggregated batteries (<5MW) to participate in our new framework. However, the amount of participation remains low.
- Medium participation scenario — This assumes that upfront incentives are provided to early participants (either through the Commonwealth's capacity investment scheme, trial funding from ARENA, or the tender mechanism in the draft rule; see appendix B.3). We also assume that future regulatory change will give VSRPs preferential network or market access.
- High participation scenario — This assumes a take-up rate supported by ongoing substantial incentives. These could be access to other markets (for example, capacity), preferential network access (for example, flexible export limits), or an enduring incentive scheme.

Source: AEMC

4.2.2 Creating new incentive mechanisms would contribute to the NEO

The Commission has explicitly considered and assessed the impact of the dispatch mode tender mechanism against the NEO.

The draft incentive mechanism has been designed with a cap on total incentive payments of $50m. These payments to VSRPs would be recovered by AEMO through Market Participants, and ultimately, customers. The draft rule also ensures that customers retain a benefit greater than the cost of providing this incentive. We do this by requiring AEMO to only pay VSRPs half the value of its benefit to customers.

Our draft rule on the tender mechanism balances the costs of implementation and complying with the policy over time against the benefits. It does this by providing AEMO with flexibility in how it operates the tender process. Through this we are minimising the potential implementation costs and complexity associated with providing funding.

Given the significant benefits from increased participation in dispatch mode, we consider that the benefits identified outweigh the costs of providing this additional incentive mechanism.

Therefore, the Commission considers the draft incentive mechanism would be in the long-term interest of consumers.

4.2.3 Creating a new monitoring and reporting framework would contribute to the NEO

The Commission has assessed the qualitative costs and benefits from introducing a monitoring and reporting framework for unscheduled price-responsive resources. We consider that the identified benefits of the draft monitoring and reporting rule outweigh the costs, and that the draft monitoring and reporting rule would better contribute to the NEO than the other options. Therefore, introducing the draft monitoring and reporting framework is likely to be in the long-term interest of consumers.

We do not consider detailed cost estimates are required to reach this conclusion because the cost of the framework is unlikely to be material. Our analysis against the relevant assessment criteria is outlined below.

The draft rule is resilient and future proof

The main benefits from the monitoring and reporting approach in the draft rule are that it will assist the market bodies to decide if and when changes are needed to AEMO's forecasting methods. This will include determining if structural changes to the way that forecasting is done in the NEM are needed (for example, placing some forecasting responsibility on retailers). We consider that this approach is likely to result in timely and effective reforms being made to improve demand forecasting in the NEM in the future. This has the potential to materially increase allocative, productive and dynamic efficiency in the long run. Compared to the alternative of AEMO's proposal, the alternative market model and no rule, this rule provides the most resilience.

Improves efficiency of investment and operations

The draft rule provides increased transparency on deviations between forecast and actual demand and measures taken to account for unscheduled price-responsive resources. If this is successful it would improve signals to the market for their investment and operations.

All market participants and consumers would benefit from increased information sharing and more efficient operation of the market.

Balances implementation cost and complexity against the benefits

The draft rule has been developed with the aim of minimising costs for market participants while maximising benefits to the market. By developing a more preferable draft rule we have sought to reduce the costs of implementing a potentially more expensive and complex solution.

Market bodies are the most impacted stakeholders as they are required to gather data, assess and report on the different factors identified. The draft rule extends AEMO's and the AER's functions in these areas. We expect that this would require some additional resources from both bodies. However, we consider that the functions enshrined in the draft rule are largely similar to functions that AEMO and the AER are likely to undertake in-house over time regardless of the draft rule. This is because the market bodies will likely focus an increasing amount of resources to address the issues associated with the growing amount of unscheduled price-responsive resource. The increase in costs as a result of that being done formally and publicly is unlikely to be material.

A Our new framework would allow for easier participation in dispatch

Section 3.2 set out the Commission's reasons for introducing a 'dispatch mode' in the NEM. This appendix sets out the details of the framework.

This appendix outlines:

- an overview of how participants would be able to aggregate resources to participate in central dispatch appendix A.1
- design details for how VSRs would be treated in central dispatch appendix A.2
- the flexibility offered to VSRs through being able to temporarily deactivate and hibernate appendix A.3
- how VSRPs would manage distribution network limits appendix A.4
- a worked example appendix A.5
- the implementation timeline for establishing VSRs appendix A.6.

A.1 Participants would be able to aggregate resources and participate in central dispatch

Our draft rule allows participants to nominate qualifying resources as a VSR which can participate in central dispatch processes.[83] Multiple VSRs can also be aggregated to participate in central dispatch as if they were a single resource if approved by AEMO.[84] This decision is similar to the dispatch mode proposed in AEMO's rule change request.[85]

The key design elements of VSRs are explained further in Box 5 below.

Box 5: Voluntarily Scheduled Resources (VSR)

The Commission's draft rule allows participants to nominate a qualifying resource as a VSR and participate in central dispatch.

The underlying connection point classification for resources nominated as a VSR would not change. For instance, if a retailer (Market Customer) nominates one of their market connection point as VSR, this would still be a market connection point but would also have the nomination of VSR.

A participant who has nominated a VSR would be referred to as a voluntary scheduled resource provider (VSRP) with respect to this VSR. However, they would retain their existing registration category, for example, IRP or Market Customer.

A VSRP can apply to AEMO to aggregate two or more VSRs such that they are treated as one for the purposes of central dispatch. Where aggregation is approved by AEMO, it is the responsibility of the VSRP to ensure the net performance of the VSR matches its dispatch obligations. AEMO may also impose conditions in connection with such an aggregation.

Note: The rule change proposed establishing a light scheduled unit (LSU); when comparing the draft determination and rule to the request, the proposed VSR is a similar concept to an LSU.

83 See clause 3.10A.1(a) of the draft rule.

84 See clause 3.8.3(a3) of the draft rule.

85 AEMO, Rule change request – Scheduled Lite Mechanism in the National Electricity Market, p. 14.

A.2 We have utilised the bi-directional unit design

In integrating VSRs into central dispatch, we have utilised several design elements from the bidirectional unit (BDU) design. Using the BDU design allows bids for both generation and load, providing flexibility for how VSRs can operate in central dispatch.

The BDU was established in the Commission's final rule for *Integrating Energy Storage Systems into the NEM* (IESS). This section should be read with Appendix A.3.2 of the Commission's final determination for IESS.[86]

A.2.1 The draft rule allows aggregated resources to operate like other scheduled resources

Where a VSR comprises several aggregated resources, they would be treated as one dispatchable resource. This aggregated VSR would operate similarly to a scheduled BDU in market systems, explained further in appendix A.2.3.

Box 6: Aggregated VSRs in central dispatch

Appendix A.1 outlined that participants can aggregate eligible resources together to participate as if they are a single resource if approved by AEMO. While each eligible resource is nominated as a VSR, where they are aggregated together, the term VSR would apply to the aggregation as a whole and not the individual resources within the aggregation.

In the following sections, the term VSR would apply to the aggregation as a whole and not the individual resources within it unless otherwise specified.

To nominate an eligible resource as a VSR, Market Participants may be registered as an IRP, Market Customer or Generator under the existing participant registration framework in Chapter 2 of the NER. The draft rule establishes the new definition of VSRP, to assist in clarifying participants who have established a VSR in the rules.[87]

A participant is eligible to nominate qualifying resources that have the following classifications as a VSR: [88]

- a market generating unit that is a non-scheduled generating unit
- a market bidirectional unit that is a non-scheduled bidirectional unit
- a *market connection point* that is *non-scheduled load*
- one or more *small generating units* or *small bidirectional units* (or any combination) at a *small resource connection point* classified as a *market connection point*.

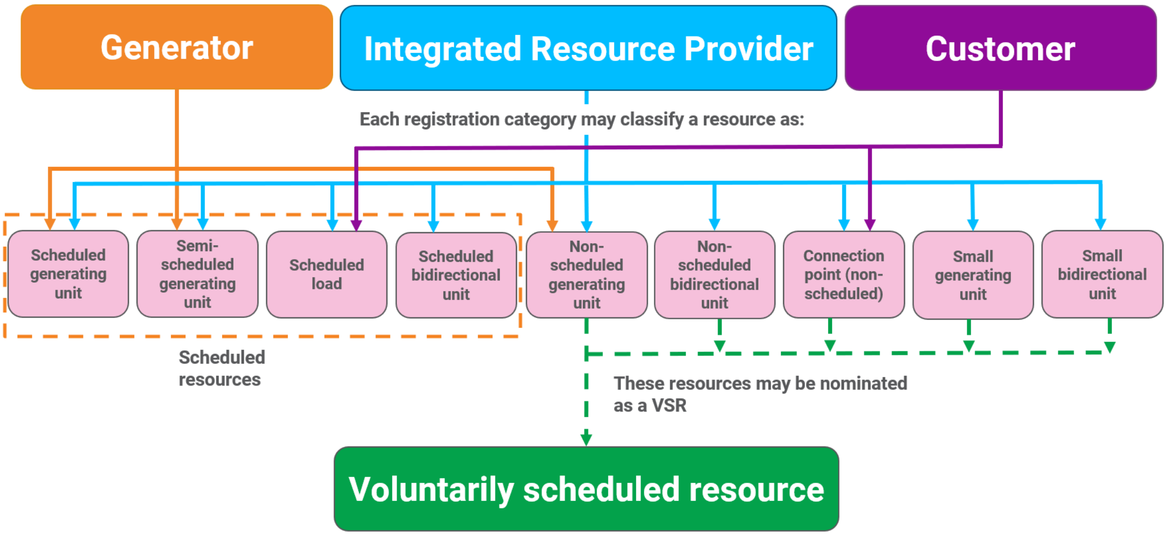
This is outlined in Figure A.1 below.

86 The IESS final determination is available here.

87 See chapter 10 of the draft rule.

88 See clause 3.10A1(a) of the draft rule.

Figure A.1: Classifications eligible to be nominated as a VSR



Source: AEMC
Note: Generator, Integrated Resource Provider and Customer refer to the chapter 2 registration categories. Not all chapter 2 registration categories have been shown here.

An example of each of these is outlined in Table A.1 below.

Table A.1: Resources that can be nominated as a VSR

Participant registration	Label	Resource/classification	Example of resource type
IRP or Market Customer	Market Customer	End user connection point (non-scheduled load), classified by a Market Customer as a market connection point	Large users, VPPs, aggregated demand response portfolio
IRP or Generator	Non-Scheduled Generator	Non-scheduled generating unit: Non-exempt generating unit with nameplate rating <30 MW	20 MW diesel generator, not exempt
IRP	Non-Scheduled IRP	Non-scheduled BDU: Non-exempt BDU with nameplate rating <5 MW	3 MW battery in a registered hybrid system
IRP	Small Resource Aggregator	Small resource connection point: small generating unit and/or small BDU (on its own connection point) classified by an IRP (Small Resource Aggregator) as a market connection point	Exempt 1 MW battery on its own connection point Exempt 2 MW cogeneration plant on its own connection point

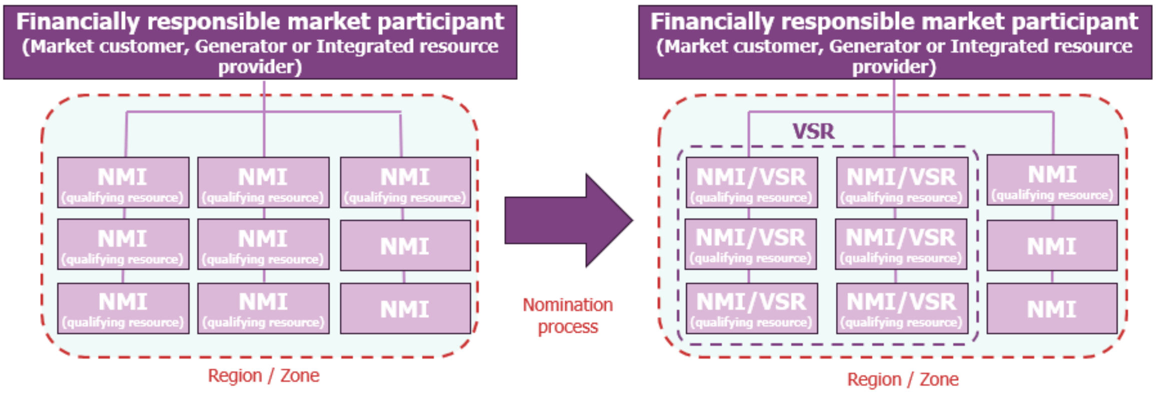
Source: AEMO, Rule change request – Scheduled Lite Mechanism in the National Electricity Market, p. 22.

The market participant will apply to AEMO to nominate its *qualifying resource* as a VSR or to apply for two or more *qualifying resources* to be aggregated as a single VSR. In applying to AEMO, the participant must:[89]

- identify the NMI and connection point associated with the *qualifying resource*
- demonstrate how the *qualifying resource* meets the requirements set by AEMO in the Voluntary scheduled resources guideline.

A simplified example is provided below:

Figure A.2: VSR nomination process



Source: AEMC
Note: The FRMP chooses which qualifying resources (NMI's) within the same region (and zone) to nominate as a VSR. Including whether to aggregate them to be treated as if they were one resource for the purposes of dispatch.

The VSR would receive a dispatchable unit identifier (DUID) and be represented in market systems by this DUID.[90]

The VSRP would be the FRMP for the resource it is nominating as a VSR. Where the VSRP ceases to be the FRMP, such as if a customer changes retailer, the VSRP is required to immediately denominate the resource as a VSR.[91] This mirrors existing requirements for ancillary services units that cease to meet the requirements for classification.[92]

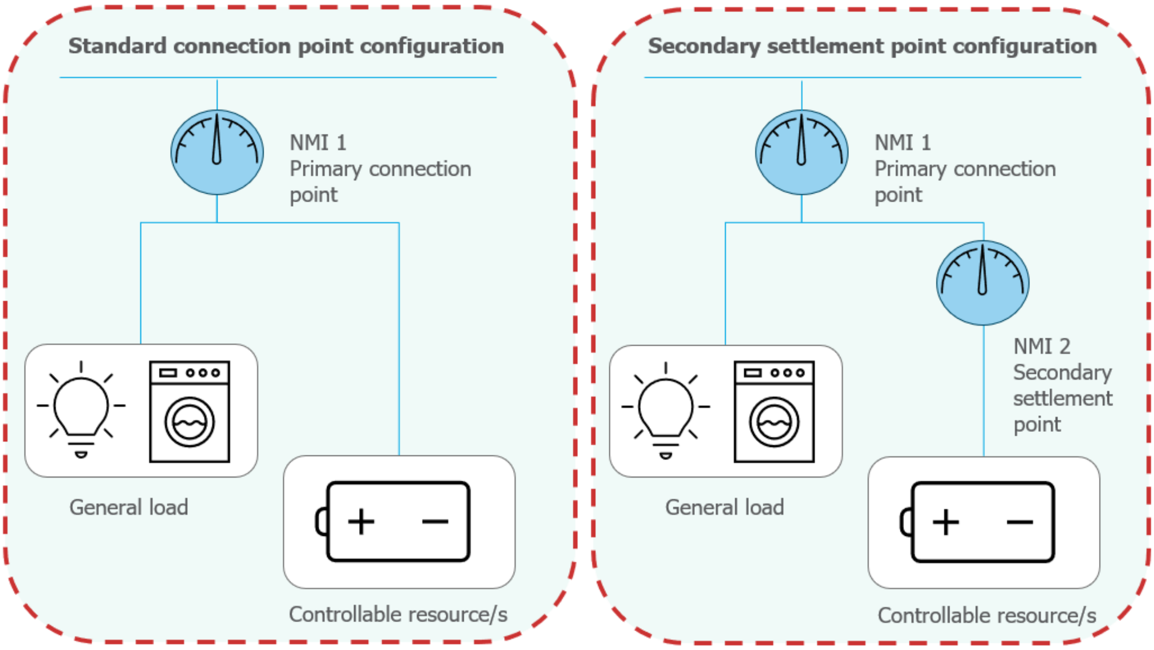
VSRPs may aggregate resources at standard connection points, secondary settlement points or a mixture of the two.[93] If a VSRP nominates a resource at a secondary settlement point as a VSR, the VSRP would bid and be dispatched for the response from the second settlement point/s.

The Commission's draft determination for *Unlocking CER Benefits Through Flexible Trading* outlined an option for establishing a second settlement point.[94] This allows flexible resources to be separately metered, and provided to market settlement systems, from the rest of the load at the primary connection point.

Figure A.3 shows a potential configuration of a second settlement point.

89 See clauses 3.10A.1(b) and 3.8.3 of the draft rule.
90 To avoid doubt, where a VSR comprises aggregated resources, the DUID would refer to the aggregated VSR and not each individual resource within the aggregation.
91 See clause 3.10A.1(m) of the draft rule.
92 See clause 2.3D.2(e) of the NER.
93 VSRPs may also nominate resources at embedded network child connection points, as long as they are an on-market connection point.
94 AEMC, Unlocking CER benefits through flexible trading, Draft rule determination, 29 February 2024, p. iii.

Figure A.3: Comparison of standard versus secondary settlement point configuration



Source: AEMC

The above diagram is a simplified version of a possible use case for secondary connection points. Consumers would have the flexibility to use second settlement points in a configuration that works best for them. For instance, households with rooftop solar can still use the output for self-consumption and won't be paying to use their own generation. This is because subtractive settlement arrangements are proposed to apply between the primary connection point and secondary settlement point(s).[95]

The location of controllable resources in the metering configuration would impact whether the VSRP needs to incorporate their output in their bids and subsequent dispatch.

Zonal aggregation

Participants can aggregate VSRs provided that each VSR is within the same zone, with the zones to be defined by AEMO in the VSR guideline.[96] AEMO would have discretion in deciding what zones are appropriate for VSRs in the guideline process, which could include retaining a regional approach.[97] AEMO has proposed that the aggregation process, including the zonal requirements, would be managed mainly through the existing portfolio management processes.[98]

AEMO has proposed that initially the zones would be consistent with the process for aggregating wholesale demand response units (WDRUs), which is that each resource is contained within a same load forecasting area.[99] Currently there are three load forecasting zones in Queensland with one forecasting area for each other NEM region.[100] We recognise that a zonal requirement may

95 AEMC, Unlocking CER benefits through flexible trading, Draft rule determination, p. 23.
96 See Section B.1.1 of the consultation paper for further information on the zonal requirement.
97 See clause 3.10A.3(c)(1) of the draft rule.
98 AEMO, Rule change request – Scheduled Lite Mechanism in the National Electricity Market, pp. 92-93.
99 AEMO, Wholesale Demand Response Guidelines, 24 June 2021, p. 7.
100 AEMO, SO_OP_3710 — Load Forecasting, 30 May 2023, p. 13.

limit participants' ability to aggregate enough resources to participate. However, the principles that AEMO must consider when developing the zones, outlined in appendix A.2.4, aim to mitigate this limitation.

A.2.2 We have balanced requirements between the rules and Guidelines

In establishing the VSR nomination process, we have carefully considered whether requirements should be defined in the rules or in AEMO guidelines. Our approach is that the rules would define obligations for participating in central dispatch, and AEMO would define technical details for how VSRs should participate in the new Voluntary scheduled resource guidelines (VSR guideline).

We consider that this approach is best as it:

- Clearly defines the obligations for VSRPs and leverages the Commission's previous work through IESS. This will create certainty for market participants as the NER provides stability and familiarity through the application of existing regulations. See appendix A.2.3 and appendix A.2.5.
- Empowers AEMO to outline the technical details for participation, which they are best placed to do. This will allow AEMO to update these details more regularly than if they were placed in the rules and allow them to be tailored to the requirements of participants utilising aggregated small resources. These details are outlined in appendix A.2.4.

This approach was tested with the TWG, who broadly agreed with the proposed balance between rules and guidelines.[101]

A.2.3 The draft rule incorporates VSRs into the existing rules for central dispatch operations

The requirements for how VSRs operate in central dispatch are defined in our draft rule and broadly follow a similar process for scheduled BDUs. At a high level, the draft rule sets out central dispatch obligations for VSRPs across:

- bidding
- dispatch
- conformance
- short-term projected assessment of system adequacy (ST PASA)
- data requirements.

VSRs would be defined as a scheduled resource in the rules and would be subject to the provisions that apply for scheduled resources, except as described in this appendix and draft rule. The obligations for opt-out and hibernated VSRs are explored in appendix A.3.

Bidding

For each VSR, the VSRP would bid in their willingness to generate or consume energy in 20 price quantity pairs, 10 each for generation and load. The bidding process for a VSR would be the same as the arrangements for scheduled bi-directional units, such as:[102]

- Bids may be for resources that include generation, load and bi-directional resources. They therefore may contain up to 20 price and volume bands.
- Bids would include all components applicable to other scheduled resources. This includes, for example, a ramp-up and down rate, price-volume pairs, and maximum availability.

101 AEMC, TWG Minutes #5, 17 April 2024, p. 2.

102 See Clauses 3.8.6 and 3.8.22A of the draft rule.

- Bids must reflect the physical capability of the VSR, such that the unit can respond to a dispatch target in the required time frames.
- Bids and rebids submitted for a VSR must not be false or misleading.

Where second settlement point/s are used, described in appendix A.1, only the response from the resource at the second settlement point would be bid in.

VSRs may also participate in the regulation and contingency FCAS markets, provided they comply with their relevant technical requirements, seeappendix B.1.2. The bidding process for these markets would be the same as for scheduled BDUs.[103]

Consistent with the existing bidding process, the minimum incremental bid quantity would be 1 MW. We acknowledge that some stakeholders expressed that a 1 MW increment is too high and may limit participation.[104] We consider that while the 1 MW bid limit may limit some participation it would only occur when aggregations are small and we welcome stakeholder feedback on the materiality of this limitation. Changing the bidding increment would require changes to NEMDE and related systems.[105] The Commission would consider the costs of these required changes with the potential benefits outlined by stakeholders in deciding whether a change is required.

Dispatch

VSRs would be incorporated into the existing NEM dispatch process, including co-optimisation between energy and FCAS dispatch. Dispatch instructions would be generated every five minutes, consistent with the NEM spot market and issued to each DUID.

When dispatched, the VSRP would receive a single bi-directional dispatch instruction representing the net flow to be achieved by the VSR in respect of its DUID.[106] This dispatch instruction would be positive where the VSR is being dispatched to discharge, and negative where it is being dispatched to charge. The VRSP would also obtain an enablement for each FCAS service where relevant.

In the example of an aggregated VSR, if the VSRP receives a dispatch instruction to generate 10MW. The VSRP must ensure that the sum of all flows across the aggregated NMIs in the VSR is equal to 10MW at the end of the dispatch interval. In doing this, some NMIs may be consuming power while others are generating. For the purposes of complying with dispatch instructions, it does not matter what each individual VSR is doing as long as the net response matches the dispatch instruction.

Conformance

The conformance of VSRs would be assessed in real-time against criteria developed by AEMO through the VSR guideline.[107] This allows AEMO to consider participants' feedback on the most appropriate set of conformance criteria for VSRs and for these to be more easily changed over time.[108]

This is consistent with the conformance criteria for wholesale demand response units, which are set out by AEMO through a guideline.[109]

103 See clause 3.8.7A of the NER.

104 Submissions to the consultation paper, Grids, p. 8, sonnen, p. 5, SwitchDin, p. 5.

105 AEMO, Scheduled Lite – Draft High Level Design, June 2022, p. 50.

106 See clause 4.9.2(a) of the draft rule.

107 See clause 3.10A.3(b)(5)(iv) of the draft rule.

108 Submissions to the consultation paper, EUAA, p. 7, Mondo, p. 8, Red Lumo, pp. 1-2.

109 See clause 3.8.23A of the NER.

We acknowledge that AEMO would face a complex trade-off in setting conformance criteria to reduce the barriers to entry by aggregated VSRs and ensuring reliable participation in dispatch. The Commission's guideline principles in appendix A.2.4 aim to guide AEMO and participants in managing this trade-off.

Where a VSR fails to respond to a dispatch instruction within a tolerable time and accuracy, as determined by AEMO, the VSR:[110]

- would be declared and identified as non-conforming
- cannot be used as the basis for setting spot prices.

AEMO must advise the VSRP that the VSR is non-conforming and request a reason for this. AEMO may also request that the VSRP submit modified parameters for the VSR based on this non-conformance.[111]

The VSR would continue to be declared non-conforming until AEMO is satisfied that the VSR would respond to future dispatch requirements as required. Where a VSR continues to be non-conforming, after a reasonable period, AEMO must prepare a report describing this non-conformance and forward it to the VSRP and the AER.[112] The AER assesses compliance with the rules separately from the conformance process, and may investigate instances of non-conformance to assess whether the VSRP was compliant with the rules.

Non-conforming VSRs are still eligible to temporarily deactivate or hibernate; see appendix A.3 for more information.

ST PASA

VSRPs would be subject to the same ST PASA requirements for VSRs as other scheduled resources. For example, over the 7-day ST PASA horizon, the VSRP would need to provide for each VSR:[113]

- available capacity for each trading interval
- PASA availability for each trading interval
- if applicable, projected daily energy availability.

PASA is the principal method of indicating a forecast of electricity system reliability to the NEM. As VSRs would be participating in central dispatch, having information about their availability in ST PASA ensures that AEMO can adequately manage the power system.

VSRPs would not need to submit MT PASA information for their VSR. We consider that requiring VSRPs to provide the forecast availability of their VSR for the next three years

However, they would need to provide demand side participation (DSP) information for the VSR.[114] AEMO would use the DSP information in their longer-term planning processes. This approach is consistent with the Commission's decisions for WDRUs.

Data requirements

VSR would be required to have appropriate remote monitoring equipment necessary for AEMO to discharge its market and power system security functions.[115] AEMO would have discretion on the

110 See Clause 3.8.23B(b) of the draft rule.
111 See Clause 3.8.23B(c) of the draft rule.
112 See Clause 3.8.23B(f) of the draft rule.
113 See Clause 3.7.3 of the draft rule.
114 See Clause 3.7D of the draft rule.
115 See Clause 4.11.1(d) of the draft rule.

form of these requirements which would be outlined in the VSR guideline. This also allows AEMO to consider specific arrangements based on different VSRs and consider stakeholder concerns that a 'one size fits all' approach is not suitable.[116]

A.2.4 A new AEMO guideline would outline technical requirements for participation

AEMO would define the required technical details for how VSRs participate in central dispatch through a new VSR guideline. This rule change provides pathways for currently unscheduled resources to participate in central dispatch, which can comprise various different types of technology which may have different speeds of technological advancement. Empowering AEMO to define the technical details of participating through a guideline allows these technical advancements to be more quickly updated than if they were in the rules.

Our draft rule requires the VSR guideline to outline the requirements and processes for:[117]

- nominating a qualifying resource as a VSR and aggregating VSRs
- participants to test the individual or aggregated capability of their resources to participate in central dispatch before formally nominating these resources as a VSR
- operational requirements of VSRs including:
  - the types of data to be provided by a VSRP to AEMO and by AEMO back to the VSRP
  - telemetry and communication requirements for VSRs
  - minimum threshold for nameplate or combined nameplate rating for nominating a VSR
  - VSR conformance criteria
  - acceptable types of metering installations for participating connection points
  - requirements for sharing data with DNSPs
- VSRPs requesting to temporarily deactivate or hibernate a VSR and the process for reactivating and resuming operation in central dispatch
- information to be provided by temporarily deactivated or hibernated VSRs
- any other information AEMO considers reasonably necessary.

The VSR guideline would also outline the zonal aggregation requirements for VSRs, including:[118]

- a methodology for determining zones in which VSRs can be aggregated, including applicable loss factors for VSRs
- requirements and conditions for VSRPs when aggregating VSRs
- necessary guidance for VSRPs on the process for aggregating VSRs to relevant zones
- any relevant validation process for AEMO.

AEMO would be required to follow the Rules' consultation procedures in developing the guideline.[119] To ensure that the guidelines are fit for purpose after VSRs have entered the market, AEMO will be required to review these guidelines three years after the commencement of the rule.[120]

Outside of the required review, AEMO may also choose to review this guideline when they consider changes are required.[121]

116 Mondo, submission to the consultation paper, p. 6.
117 See clause 3.10A.3(b) of the draft rule.
118 See clause 3.10A.3(c) of the draft rule.
119 See Rule 8.9 of the NER.
120 See clause 11.[XXX].3(c) of the draft rule.
121 See clause 3.10A.3(e) of the draft rule.

Principles when creating the guideline

In developing the new guideline, AEMO would need to make decisions on the cost of facilitating VSRs, as well as the technical requirements for VSRs. These decisions are likely to impact the level of participation in VSRs, as outlined below.

We are proposing that AEMO must have regard to the following factors when developing the VSR guideline:[122]

- Seek to minimise total cost of facilitating the rule change, and in doing so balance the cost to participants in operating a VSR as well as AEMOs costs of facilitating VSRs.
  - For example, through consultation AEMO may choose to develop a more expensive technical option if it means this expense would significantly reduce costs for participants.
- Balance the technical requirements for VSRs with the expected level of participation from these requirements.
  - For example, balance the benefits from greater participation with lower technical requirements and the benefits from greater technical requirements with lower participation. This would also allow AEMO to apply different technical requirement based on the size of the VSR. For instance a 150 MW VSR may require different technical requirements than a 10 MW VSR.
  - This principle would also apply to AEMO determining zonal requirements for participation. For example, AEMO must balance the benefits from less strict zonal requirements, such as regional, with the need for VSRs to be in zones that accurately reflect the power system.
- Any other matter determined by AEMO.

These principles aim to assist AEMO and stakeholders in balancing these trade-offs, while still giving AEMO flexibility to determine the most appropriate requirements for VSRs.

A.2.5 Other requirements that apply to VSRs

VSR would be eligible to be directed

VSRs would be able to be directed by AEMO under clause 4.8.9 instructions, which are in line with other scheduled resources. Directions for aggregated VSRs would apply at the aggregated level.

AEMO can issue clause 4.8.9 directions to maintain or re-establish the power system in a secure, satisfactory, or reliable operating state. Directions may be issued to scheduled Registered Participants, including plant or market generating units.[123]

We consider that being subject to directions would not add any material complexity or pose a significant disincentive to nominate a VSR. This is because VSRPs are already required to reflect the capability of their VSRs through their bids, and this capability can be directed if needed.

We expect that VSRs would not be directed often in the short term. If they are directed, they would be eligible for compensation under certain conditions.[124] Furthermore, under the ISF final rule, regularly directed participants can request to enter into a contract with AEMO and this has the potential to be a positive for participants.[125]

VSRs would provide Enhancing reserve information

122 See clause 3.10A.3(d) of the draft rule.

123 See clause 4.8.9(a1) of the NER.

124 See clause 3.15.7 of the NER.

125 AEMC, Improving security frameworks for the energy transition, Rule determination, 28 March 2024, p. 69.

Applicable information about VSRs energy availability will be published in operational time frames, in line with the Commission's recent determination for *Enhancing reserve information*.[126] VSRPs would provide this information for the VSR as a whole, that is at the aggregated level and not for each individual resource that may be aggregated.[127]

The final rule for *Enhancing reserve information* requires the publication of information on energy availability in the operational time frame, including:

- state of charge (SOC)
- daily energy constraint
- maximum storage capacity.

VSRs are required to provide AEMO with the aggregated actual generation, actual load and actual energy stored as part of their operation. Extending the *Enhancing reserve information* decision to VSRs maintains the signals participants would have on the levels of storage available in operational time frames.

VSRs would be eligible for frequency performance payment but not required to provide mandatory primary frequency response

VSRs would not be required to provide mandatory primary frequency response (PFR) but would be eligible for FPPs.

The AEMC's final rule for *Clarifying Mandatory Primary Frequency Response Obligations For Bidirectional Units* outlined that batteries must provide PFR when exporting or importing energy, including when providing a regulation service.[128] We consider that the relative immaturity of smaller distributed resources, which are expected to participate as a VSR, justify their exclusion from providing mandatory PFR.

The AEMC's final rule for *Primary Frequency Response Incentive Arrangements* introduces new FPP arrangements.[129] These incentivise market participants to operate their plant in a way that helps to control power system frequency.

VSRs would be defined as an eligible unit and be able to receive FPP, subject to being able to comply with relevant requirements.[130] See appendix B.1.3 for further details on FPPs.

VSR capacity would count as an offset in the retailer reliability obligation (RRO)

VSR capacity would offset the FRMPs liable load in the RRO.[131] Liable Entities must provide a Net Contract Position report to the AER that summarises their level of firm contract cover for a prescribed gap period. In this report the capacity of sources, such as VSR's, must be assessed for their firmness against criteria described in the AER's Contracts and Firmness Guidelines. [132] After the end of the gap period, providing the trigger criteria have been reached, a Liable Entity's actual demand is scaled to the reference 50PoE level. This value is compared with the NCP reported contract position for the same period and would be effectively reduced by, amongst other factors, the Liable Entity's firmness adjusted VSR capacity.

126 AEMC, Enhancing reserve information, Rule determination, 2024, available here.

127 See clause 3.7G of the draft rule.

128 AEMC, Clarifying mandatory primary frequency response obligations for bidirectional plant, Rule determination, 7 March 2024, p. i.

129 AEMC, Primary frequency response incentive arrangements, Rule determination, 8 September 2022, p. i.

130 See clause 3.15.6AA of the draft rule.

131 See clause 4A.E.1(e) of the draft rule.

132 See clause 4A.E.1 of the rules.

To ensure that these resources are appropriately recognised the AER would need to review the Contracts and Firmness guidelines to ensure that appropriate guidance is provided to Auditors performing the firmness assessments.[133]

VSRs would not be able to be constrained-on

VSRs would not be able to be constrained-on due to network constraints.

Network constraints may cause a scheduled generator, bidirectional unit or WDRU to be constrained-on in accordance with its availability but may not be taken into account in determining the spot price.[134]When constrained-on, participants are not eligible for compensation due to their bid being below the spot price.

Excluding VSRs from being able to be constrained-on is required to recognise that the resources participating may be owned by residential customers. The lack of compensation from being constrained-on can represent a risk to participating as a VSR as it may impact the value proposition for signing up customer resources.

We acknowledge that the circumstances in which a VSR could be constrained-on are limited and may not materialise. However, removing this risk would decrease the risks of participating as VSR. If network constraints do need to be managed using a VSR they may be directed, as outlined above.

Changes to ramp rates are required for VSRs

In consultation with AEMO during the preparation of the draft rule, the calculation of minimum ramp rates was identified as a potential issue for VSRs.

VSRPs would provide minimum and maximum ramp rates for the VSR for use in the verification of their offers.[135] For aggregated VSRs, the minimum ramp rate would be calculated as the sum of the minimum ramp rate requirements for each individual resource. In this calculation the minimum ramp rate requirement is the lower of 3MW/min or 3% of maximum consumption or generation, rounded to the nearest whole number greater than 0.[136]

As the minimum ramp rate requirement is rounded before summing together, for small resources this could result in unusual outcomes. For instance, 3% of a 5 kW battery's rated output would result in a 0.015 kW/min ramp rate being rounded to 1 MW/minute. This calculation would occur across each VSR in the aggregated VSR before being summed together to give the minimum ramp rate for the VSR.

Our draft rule amends the ramp rate calculation such that the aggregated VSR capacity is used when calculating the lower of 3MW/min or 3% of maximum consumption or generation before rounding.[137] We are seeking stakeholder feedback on this amendment and whether this change would impact existing participants.

Further changes may be required to existing rules

The FCAS nomination process may need to be amended to better accommodate VSRs. We are seeking stakeholder feedback on whether amendments are required and the impact they may have on existing participants.

133 See 11.[XXX].2 of the draft rule.

134 See clause 3.9.7 of the NER.

135 See clause 3.8.3(b) of the draft rule.

136 See *minimum ramp rate requirement* definition in Chapter 10 of the NER.

137 See clause 3.8.3A(b)(1)(iv) of the draft rule.

In developing the draft rule AEMO raised that the existing process for nominating ancillary service units may cause issues for VSRs. Market participants can classify resources at market connection points as an ancillary service unit. For instance, where existing VPPs are participating in contingency FCAS markets. If the end customer moves out of the VPP, and ceases to be an ancillary service unit, the market participant is required to immediately notify AEMO of this.[138]

In practice, we have been made aware that participants are not declassifying the customer as one of their ancillary service units in a timely manner. This prevents a new participant classifying the customer as an ancillary service unit, such as where the customer joins a new VPP that is participating in contingency FCAS. In the context of VSRs, a resource could not be aggregated into a VSR that is also an ancillary service unit until the previous market participant has declassified the resource. This may prevent the speed and ease of resources joining or moving between VSRs.

We are seeking stakeholder feedback on what changes could be made to improve this process, including whether AEMO should be able to declassify ancillary service units.

A.3 The draft rule allows for flexibility in when participants operate in the mechanism

Our draft rule introduces two options that allow VSRPs to remove a VSR from dispatch obligations over different time frames. These options recognise the challenges aggregated portfolios may face if required to continually participate in central dispatch.

The two options being introduced are:

- **Temporary deactivation —** would allow VSRPs to remove a VSR from dispatch obligations for up to seven days.
- **Hibernate —** would allow VSRPs to remove a VSR from dispatch obligations across longer time frames, up to 18 months.

These options provide a necessary safety net for VSRs with technical issues in operational time frames and recognise that some resources may only be able to participate over specific periods. We consider that this flexibility is necessary to assist in encouraging participation, as the risks of central dispatch operation can be managed.

A.3.1 Aggregated price-responsive resources need to be treated differently from grid-scale resources

These two options are required because VSRs comprised of aggregated resources may not easily be able to address technical issues while complying with dispatch requirements. Furthermore, some resources may only be able to participate in dispatch processes over specific time frames.

Larger scheduled resources are designed for constant participation in central dispatch and can disconnect from the grid when they encounter an issue to resolve it.

VSRs, by contrast, may be comprised of aggregated resources that continue consuming or producing power where there is an issue. For example, where a VSR is composed of controllable resources as well as other passive loads connected behind a standard connection point, see Figure A.3. If there is an issue with any of the software being used to control the VSR, then the VSRP would not be able to comply with dispatch instructions. Facing non-conformance for each dispatch interval that they fail to comply until they manage to denominate the VSR.

138 See clauses 2.3D.2(e) and 2.3D.1(f)(3) of the NER.

This need for flexibility was highlighted during our TWG, with participants noting that any mechanism should offer flexibility to assist participants in overcoming the complexity of participation.[139]

A.3.2 Participants would be able to temporarily deactivate in operational time frames

The Commission has made a draft determination that VSRPs may temporarily deactivate a VSR. This process would allow participants to remove themselves from dispatch obligations, up to a maximum of seven days, to align with ST PASA time frames. This process offers a 'safety net' for participants when they are temporarily unable to meet dispatch instructions.

The temporary deactivation process is similar to the opt-out process proposed in the rule change request. The opt-out process was also supported in previous industry engagement by AEMO on the design of a scheduled lite mechanism, with feedback noting that opt-out is essential for a voluntary scheme.[140]

Temporarily deactivation process

A VSRP may submit a deactivation request to AEMO to temporarily deactivate a VSR. This request would apply to each NMI in the VSR. This request will specify:[141]

- the period in which the VSR would be temporarily deactivated, from at least one trading interval to a maximum of seven days
- contain any required information and be submitted per the process outlined by AEMO in the VSR guidelines.

AEMO must approve or reject a deactivation request following the criteria and timing specified in the VSR guidelines.[142] Where the VSR is approved to be temporarily deactivated:[143]

- AEMO is not required to include bids submitted by the VSRP in central dispatch or validate the bid. AEMO must also specify how deactivated resources are to be treated through the VSR guideline.
- The VSRP would be exempt from the validation of dispatch bids, conformance with and bidding in good faith provisions

To reenter the central dispatch process, a VSRP must submit a reactivation request to AEMO before the end of the deactivated period specified in their request. AEMO has to approve or reject this request per the process outlined in the VSR guidelines.[144] Where a reactivation request is rejected, the VSR would continue to be temporarily deactivated until a reactivation request is approved.

If a VSRP does not submit a reactivation request or is not approved to reenter within the seven day time frame, the VSR would automatically be moved to a hibernated status.[145] If the VSRP fails to submit a hibernation request, then VSRP ceases to be a VSRP in respect of that VSR. The relevant VSR also ceases to be a VSR and the classification that applied to the qualifying resource prior to its approval for nomination resumes.[146]

139 AEMC, TWG #5 minutes, 17 April 2024.
140 AEMO, Rule change request – Scheduled Lite Mechanism in the National Electricity Market, p. 175.
141 See clause 3.10A.2(c) of the draft rule.
142 See clauses 3.10A.2(d)-(e) of the draft rule.
143 See clause 3.10A.2(f)-(g) of the draft rule.
144 See clause 3.10A.2(i) of the draft rule.
145 See clause 3.10A.2(k) of the draft rule.
146 See clause 3.10A.2(l) of the draft rule.

A.3.3 Participants would be able to hibernate over longer time frames

The hibernation process allows participants to keep resources nominated as VSRs over periods where they do not want to participate in central dispatch. This allows an easy path to return to operating in central dispatch. For instance, a participant may only have agreements to manage resources over the summer months and would be hibernated for the remaining months.

The hibernation process removes VSRPs from central dispatch obligations for the VSR for periods beyond operational time frames. For example, if a VSRP does not want to operate a VSR over winter, they can apply to hibernate this period, rather than having to de-nominate the VSR.

Hibernation process

A VSRP may submit a hibernation request to AEMO to hibernate a VSR. This request would apply to each NMI in the VSR. This request would specify:[147]

- the period in which the VSR would be hibernated, from the period of at least 7 days to a maximum of 18 months
- contain any required information and be submitted following the process outlined by AEMO in the VSR guidelines.

AEMO must approve or reject a deactivation request per the criteria specified in the VSR guidelines.[148] For the duration of the approved hibernation period:[149]

- AEMO may impose conditions on the hibernated VSR in accordance with the VSR guidelines
- the hibernated VSR will not be scheduled resource.

To reenter the central dispatch process, a VSRP must submit a reactivation request to AEMO before the end of the hibernation period specified in their request.[150] AEMO has to approve or reject this request per the process outlined in the VSR guidelines. Where a reactivation request is rejected, the VSR would remain hibernated until their reactivation request is approved.

If a VSRP fails to submit a resumption request, then, from the end of the approved hibernation period, the VSRP ceases to be a VSRP in respect of that VSR. The relevant VSR also ceases to be a VSR and the classification that applied to the qualifying resource prior to its approval for nomination resumes.

A.4 Distribution network limits may impact participation

Our draft decision is that the VSRPs would be responsible for complying with any applicable distribution limits that apply to a resource within their VSR. Where a VSRP nominated a resource connected to the distribution network as a VSR, this resource may be subject to limits imposed by the DNSP, such as FELs.

Given that distribution level limits are not integrated into NEMDE, the VSRP would be responsible for ensuring that their bids and any subsequent dispatch comply with these limits.

147 See clause 3.10A.2(n) of the draft rule.
148 See clause 3.10A.2(o) of the draft rule.
149 See clause 3.10A.2(p)(3) of the draft rule.
150 See clause 3.10A.2(q) of the draft rule.

A.4.1 Distribution network service providers are implementing dynamic limits

CER connected to distribution networks are generally limited to a fixed export limit, typically 5kW for single-phase connections.[151] These fixed limits are set to a level that keeps shared generation from each CER connected within the network hosting capacity, particularly during high congestion.

Given the forecast uptake of rooftop solar and household batteries, DNSPs are likely to impose smaller fixed limits on new connections to keep the increase in generation within the network limits.

DNSPs are investigating FELs as a mechanism to maintain the integrity of the distribution network as customer exports continue to grow. FELs can allow consumers to export more from their resources at times and locations where there is 'spare' unallocated capacity rather than be restricted to (potentially lower) static limits.

A VSR may contain resources connected at the distribution level and be subject to FELs, for instance if the VSR includes household batteries. In this scenario the FEL would limit how much that resource can deliver, which would need to be reflected in the VSRPs bids.

A.4.2 Dispatch participants would be responsible for complying with distribution limits

The Commission's draft decision is that VSRPs must ensure that their bids and any subsequent dispatch are within any applicable FEL across their VSR. This means that the VSRP needs to ensure that each NMI in the VSR (if aggregated) would stay within any applicable FEL imposed by a DNSP at that NMI.

We consider that while FELs are still being developed by DNSPs it's not feasible to factor in any applicable FEL in dispatch instructions to VSRs. Requiring that FELs are incorporated into dispatch instructions would likely significantly increase the complexity of implementing the mechanism, and add delays in its implementation.

It's expected that over the short term, FELs would not pose a significant limit on the operation of price-responsive resources, but this may change over time, requiring their integration with dispatch instructions. As the design and implementation of FELs progress, AEMO and DNSPs can investigate incorporating FELs into dispatch instructions to VSRs.

A.4.3 Distribution limits should be designed to facilitate VSR participation

While we have not required FELs, or other distribution limits to be integrated into dispatch instructions, these limits should be designed in a way that facilitates future integration.

DNSPs should have the flexibility to deliver a FEL solution that works best for their network. However, the assets being subject to these FELs may, or could in the future, participate as a VSR. As such the Commission expects that when DNSPs are designing the systems and processes for implementing FELs, it allows for future integration with dispatch instructions for VSRs. For example, providing and updating FELs to align with the timeframe that allows bids to be adjusted.

Our draft rule includes information sharing provisions between AEMO and DNSPs

The VSR guideline also sets out any data-sharing arrangements between AEMO and DNSPs (see appendix A.2.4). This would allow for VSR information to assist in setting appropriate limits.[152] This provision can be used to ensure alignment between AEMO and DNSP systems, so FELs can be included as part dispatch instructions to VSRs in the future.

151 AER, Flexible Exports, Draft issues paper, 7 October 2022, p. 2.

152 SA Power Networks, submission to the consultation paper, p. 2.

While distribution limits would be the responsibility of the VSRP to manage, receiving these limits at an appropriate time is critical to ensure that they are reflected in the VSRPs bids. For instance, receiving a FEL or a change to a previously communicated FEL, 5 minutes before a dispatch interval, would be challenging for a VSRP rebid to reflect this. This could result in the VSR unable to meet its dispatch instruction or breaching their FEL.

During the development of FELs we encourage DNSPs to use their best endeavours to ensure any applicable FEL is communicated to VSRPs as early as possible. With any changes to this FEL communicated at least 30 minutes in advance of the change.

A.5 Worked example

The following worked example builds on the example provided to TWG members on March 4th and has been updated to reflect the terminology of the draft rule.[153]

In this example, the fictional retailer Ralph Energy has 1,200 households with behind-the-meter batteries with a contract that allows Ralph to control their batteries. The aggregated capacity of these resources is 12 MW/15.5 MWh.

Ralph Energy is registered as a Market Customer and is the FRMP for the customer NMIs it aggregates. Both passive and controllable loads are behind a single NMI, meaning Ralph Energy is responsible for all resources behind the meter at each participating site.

Nomination and aggregation

Ralph Energy nominates the NMIs it wishes to participate with as a VSR and must then apply to aggregate these together into one VSR, which would receive a DUID. Each NMI would need to be within the same zone specified by AEMO in the VSR guideline. AEMO has proposed that this process would be managed through AEMO's portfolio management functions developed for WDRM.

Data

Ralph Energy would need to provide information about its VSR to AEMO when nominating and in real-time during operation. Specifics on how this data would need to be structured and transmitted to AEMO would be defined by AEMO through the VSR guideline. A high-level overview of the data requirements is outlined in Table A.2 below.

Table A.2: Indicative VSR data requirements

Data	Description	Unit/granularity	VSR implications
Static or standing data	Site data that changes infrequently for each connection point, such as the capacity of the resources and price-responsive capacity.	A proposed new light scheduling unit guideline would outline specific data requirements.	Every NMI that Ralph wishes to nominate as a VSR must provide this standing data to AEMO.
Availability forecast (PASA)	Aggregated available capacity of generation, load and storage.	MW availability and storage in MWh across the short-term horizon.	Ralph would submit the expected availability of its VSR across the ST PASA horizon.

153 A copy of the slides, as well as the minutes from the TWG, are available on the project page.

Data	Description	Unit/granularity	VSR implications
Bids	Per IESS, a bi-directional offer that includes both generation and load, up to 20 price bands per VSR.	20 price/quantity pairs i.e. $/qty ($/MWh, MW) for each dispatch interval	Ralph would use existing market systems to submit bids to AEMO.
Telemetry/ SCADA	• Aggregated (per VSR) instantaneous period ending measurement of active power flow at NMI. • Aggregated actual generation, actual load and actual energy stored.	Data requirements would be defined in the power system communication standard.	Ralph would be required to set up appropriate communications to ensure it can provide the necessary data to AEMO

Source: AEMO

Bidding

Ralph Energy bids to charge its aggregated batteries during negative prices and discharge when prices > $300 and nothing at all other times. It would comply with existing bidding rules, such as bidding in good faith.

2 MW of the aggregated battery capacity is reserved to smooth out the passive load and manage unexpected changes to customers' load to comply with dispatch instructions.

These intentions are reflected in the table:

Table A.3: Ralph Energy VSR bidding intention

Market price range ($/ MWh)	Ralph Energy intention
<0	Customer batteries: Charge at the maximum rate, i.e. 10MW. Assuming all batteries in the fleet have a SOC available to charge. Underlying customer load: no change (2MW load) Bid intention: -12MW
0 to $300	Customer batteries: no action. Underlying customer load: no change (2MW load) Bid intention: -2MW
Above 300	Customer batteries: Discharge at the maximum rate, i.e., 10MW. This assumes all batteries in the fleet have SOC available to discharge. Underlying customer load: no change (2MW load) Bid intention: +8MW

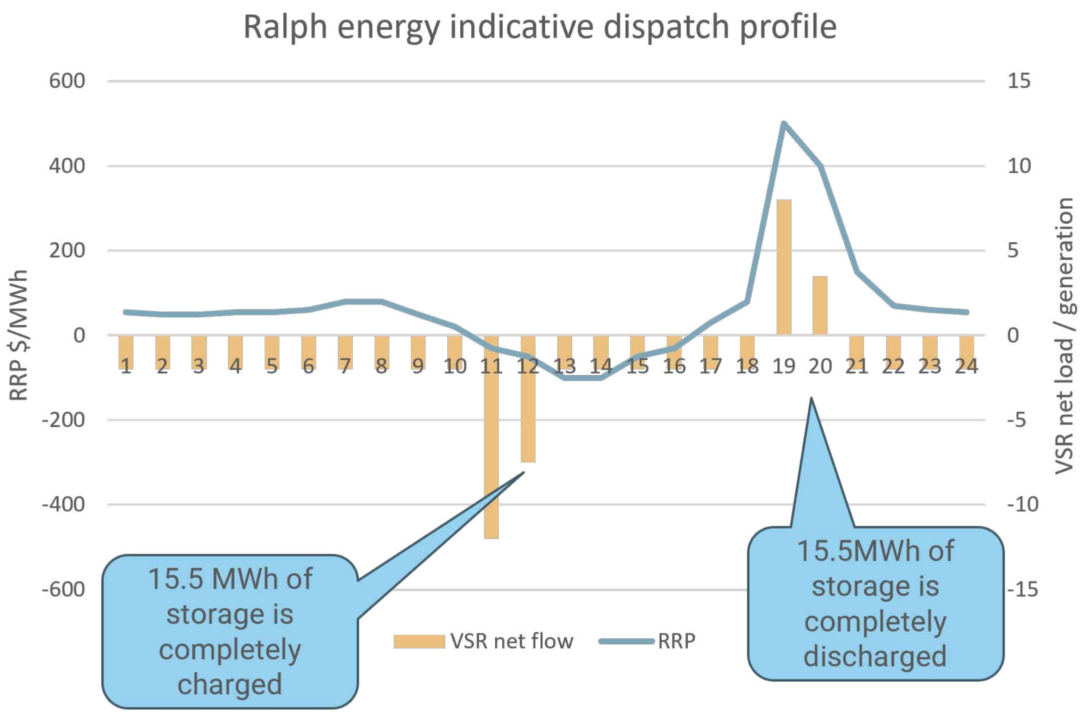
Source: AEMC
Note: limitations in the VSRs ability to charge or discharge would need to be reflected in the VSRs bids or rebids.

Dispatch

Ralph Energy's bids are sent to AEMO and incorporated into the central dispatch process (NEMDE). When dispatched, Ralph would receive a single bi-directional dispatch instruction for the

VSR. Ralph Energy would then disaggregate the dispatch instruction amongst the NMIs in the VSR and control the batteries to meet the instruction, such as linearly ramping between dispatch targets. An indicative example of Ralph Energy's VSR performance across a trading day is shown in Figure A.4 below.

Figure A.4: Ralph Energy indicative dispatch profile



Source: AEMC
Note: The aggregated battery charge and discharge response to wholesale prices is limited by aggregated capacity of 15.5 MWh. This limitation would need to be reflected by Ralph through its rebids.

Settlement and conformance

Ralph Energy's VSR would be settled in line with existing market processes. At a high level, Ralph would pay the regional price when its VSR is a net load and the regional price when it is net generation. Ralph will also be paid for any ancillary services it is enabled for, such as regulation FCAS, and receive any applicable frequency performance payments. Ralph's remaining retail customers would be settled normally per the existing arrangements.

The example assumes that the VSR exactly conformed to dispatch instructions. If this did not occur, the VSR would be subject to the process outlined in appendix A.2.3.

A.6 Implementation of dispatch would be over 18 months and commence in November 2026

The Commission notes that the scope of this draft rule is extensive and that, if implemented as final, it would result in a number of changes for AEMO to implement. These amendments in the draft rule, if implemented as final, are proposed to commence on 5 November 2026.

Prior to this AEMO would be required to develop and publish the VSR guideline by 31 December 2025.

Performing a post-implementation review is best practice given the scope of changes being introduced. We will consider whether a review is required once these amendments have been in operation for an appropriate period of time. If a review is required, we will use our self-initiation review powers to commence this.

B Additional incentives would help drive participation

Section 3.3 set out the Commission's high-level dispatch mode incentive decisions and reasons for those decisions. This appendix sets out the detailed design of those decisions. This appendix outlines:

- the incentives available to participants under the current rules (appendix B.1)
- the removal of participants from RERT cost recovery (appendix B.2)
- the new incentive mechanism (appendix B.3).

Specifically, the draft rule would:

- Exclude participants from RERT cost recovery. In practice this means that during periods where RERT is enabled and the participant is a net consumer, VSR participants would not be liable for RERT cost recovery payments.
- Introduce a time-limited incentive mechanism to provide early participants with funding to assist participation and building capabilities. This recognises that the other incentives may be insufficient in the short term to attract participation in the market.

B.1 Existing incentives will become available to participants

Section 2.2.2 sets out that the majority of benefits of participation in dispatch accrue to the market, but there are some direct benefits to participants. This section outlines the existing incentives and how a VSRP would benefit from these:

- co-optimise energy and FCAS (appendix B.1.1)
- provide regulation FCAS (appendix B.1.2)
- be eligible for frequency performance payments (appendix B.1.3).

B.1.1 Co-optimisation of energy and FCAS would maximise the capabilities of VSRs

The draft rule enables VSRs to participate in dispatch. When participating in dispatch, NEMDE will co-optimise VSR energy and FCAS bids, as it does for all scheduled resources. This would maximise the bids of VSRs in FCAS and the wholesale market by enabling their optimal dispatch.

Co-optimisation is the process of trading off between energy dispatch and FCAS enablement to achieve the total lowest cost.[154] NEMDE conducts co-optimisation of energy and FCAS bids for scheduled and semi-scheduled generating units, wholesale demand response units, and scheduled loads.[155]

Through submissions to the consultation paper and TWGs, stakeholders expressed interest in the ability to co-optimise energy and FCAS to maximise the capabilities of their VSRs.[156] By participating in dispatch, NEMDE would produce co-optimised energy and FCAS dispatch instructions and participants must manage their portfolio to conform with the instructions issued for their VSR.

This incentive would be most beneficial for unscheduled resources currently providing contingency FCAS as joining dispatch will automatically enable co-optimisation.

154 AEMO, Guide to Ancillary Services in the National Electricity Market, October 2023, p. 3.

155 AEMO, Guide to Ancillary Services in the National Electricity Market, October 2023, p. 8.

156 sonnen, submission to the consultation paper, p. 7; AEMC, TWG minutes #4, 12 March 2024.

Eligibility for co-optimisation of energy and FCAS

To be eligible for co-optimisation of energy and FCAS as a VSRP, a FRMP must:

- Nominate a qualifying resource as a VSR and be registered as an ancillary service provider.
- Be participating in the central dispatch process with that VSR. Co-optimisation would not be available for inactive or hibernating VSRs.
- Provide an FCAS trapezium for each VSR.
- Comply with the requirements in the Market Ancillary Services Specifications (MASS) and the NER in regard to the services they will provide.
- Meet technical requirements such as Automatic Generation Control (AGC) if providing regulation FCAS.

In its rule change request, AEMO noted that the technical requirements to enable traditionally unscheduled resources to co-optimise may vary as these resources' capabilities and size evolve.[157]

B.1.2 Participants would benefit through eligibility to bid in regulation FCAS

The draft rule enables VSRs to participate in dispatch. When participating in dispatch, VSRs will also be able to bid in regulation FCAS markets, subject to meeting the technical requirements. This aligns VSRs with other scheduled resources currently eligible to provide regulation FCAS and opens a new opportunity for VSRPs to participate in the NEM.

VSRPs providing regulation FCAS will benefit through receiving a settlement payment for each trading interval where they provided FCAS. This payment is calculated by using the relevant ancillary services price and the amount of the ancillary service provided in each dispatch interval.[158]

Regulation FCAS corrects supply and demand imbalances in response to minor changes to supply or demand in the NEM.[159] It is controlled centrally by AEMO. The AGC system sends control signals through Supervisory Control and Data Acquisition (SCADA) every four seconds to participants enabled to deliver regulation FCAS.[160] This alters the output of generation units or the electricity consumption of loads to correct the demand and supply imbalances.

Participation in regulation FCAS requires a resource to be scheduled so that a set point can be determined from which a response can be provided and managed.[161]

Stakeholders consistently cited access to and participation in regulation FCAS as the predominant driver to consider participation.[162] They recognised regulation FCAS as a significant incentive as it provides access to additional market streams. However, they noted there are technical challenges that need to be overcome to facilitate participation.[163]

To overcome these challenges, AEMO's SCADA Lite initiative will enable a communication stream between AEMO and a VSRP to allow a VSR to provide regulation FCAS. This bidirectional

157 AEMO, Rule change request – Scheduled Lite Mechanism in the National Electricity Market, p. 59.

158 AEMO, Settlements guide to ancillary services payment and recovery, June 2024, p. 7.

159 AEMO, Guide to Ancillary Services in the National Electricity Market, October 2023, p. 5.

160 AEMO, Market ancillary service specification, June 2024, p. 13.

161 AEMO, Market ancillary service specification, June 2024, p. 14.

162 Submissions to the consultation paper, CEC, p. 2, Enel X, p. 5, Evergen, p. 8, Shell, pp. 3-4, sonnen, p. 7, Tesla, p. 11; AEMC, TWG Minutes #4, 12 March 2024.

163 Submissions to the consultation paper, CEC, p. 2, Enel X, p. 5, Evergen, p. 8, Shell, pp. 3-4, sonnen, p. 7, Tesla, p. 11.

connection will facilitate the exchanging of operational information (telemetry and control), and means a VSR would receive the necessary signals to participate in regulation FCAS.[164]

Eligibility for regulation FCAS

To be eligible to participate in regulation FCAS markets, a VSRP must:

- Be participating in dispatch with the relevant VSR. Regulation FCAS participation would only be available for participating VSRs; not inactive or hibernating ones.
- Classify the plant as an ancillary service.[165]
- Meet technical requirements such as AGC or equivalent functionality. This is necessary to understand the output of a dispatchable unit identifier (DUID) at four-second granularity and for the resource to be able to reach a set point (output target) as requested by AEMO to supply regulation FCAS. The introduction of SCADA Lite will facilitate this.
- Comply with the relevant standards and specifications outlined in the MASS.

B.1.3 Participants can be rewarded through frequency performance payments

Under our draft rule, VSR participants would be eligible for FPPs (the FPP arrangements commence before dispatch mode does). The rules on FPPs come into effect in June 2025.[166] This aligns VSRs with other scheduled resources that will be subject to FPP arrangements.

FPPs are a new financial incentive for scheduled resources to provide helpful frequency response into the NEM.[167] Under this scheme, scheduled resources that contribute helpfully to frequency would receive payments from those that make unhelpful contributions.

At this stage, we expect all VSRs participating in dispatch would meet the FPP metering requirements through the requirements to participate as VSRs. Appropriate metering requirements for FPPs though are contained in AEMO procedures and could be subject to future change.[168]

VSRPs would likely benefit from FPPs, however, we recognise that VSRs may be negatively affected by being subject to FPPs if they do not follow their reference trajectory (or, dispatch target trajectory).[169]

Eligibility for FPPs

The draft rule includes VSRs as “eligible units” in the FPP provision and so VSRs would automatically be eligible for FPPs, provided they have the correct metering.

164 AEMO, SCADA Lite, accessed June 2024.

165 Under rule 2.3D.

166 AEMC, Primary frequency response incentive arrangements final determination, September 2022.

167 FPPs were introduced under the National Electricity Amendment (Primary frequency response incentive arrangements) Rule 2022.

168 AEMO, Frequency Contribution Factors Procedure, February 2024, p. 11.

169 Reference trajectory is the expected active power output or consumption of an eligible unit or the Residual, see AEMO’s Frequency Contribution Factors Procedure, p. 11.

B.2 Participants would be excluded from RERT cost recovery

The Commission's draft rule would amend the RERT to exclude a VSRP's adjusted consumed energy from the RERT cost recovery calculation.[170] In doing so, we recognise that by participating in dispatch, a VSRP is delivering a broader social benefit by reducing the size of the RERT event and the corresponding costs.

Participation of VSRPs in dispatch is expected to result in substantial RERT cost savings by reducing the number of times RERT is activated.[171]

AEMO continuously assesses whether forecast reliability and security are outside a relevant NEM standard.[172] If reliability and security are forecast to fall outside of these standards, AEMO may procure RERT contracts from market participants to use during forecasted lack of reserve periods.[173]

When RERT is activated by AEMO, AEMO pays those costs on behalf of consumers which are then recovered from Cost Recovery Market Participants in subsequent billing periods.[174]

Our decision to remove the adjusted consumed energy of VSRs from RERT cost recovery aligns with the Commission's decision to remove the adjusted consumed energy of scheduled bi-directional units from RERT cost calculations.[175] This came into effect through the National Electricity Amendment (Integrating Energy Storage Systems into the NEM) Rule 2021.

In making the draft rule, the Commission considers this as a potentially significant incentive, especially for large loads with some degree of price-responsiveness. However, we acknowledge that this benefit would only occur during a RERT event where the participant consumes electricity. In these circumstances it is most likely given that the price will be high, VSRs would be on aggregate exporting and not consuming.

We are interested in stakeholders' views on the materiality of this incentive. We recognise that excluding the energy from VSRs adds complexity to AEMO's RERT cost recovery systems. As such, the Commission is interested to understand the balance in the potential benefit from providing this additional incentive.

Eligibility for exclusion from RERT cost recovery

For a VSR to be excluded from RERT cost recovery, it must be participating in dispatch. The energy consumed by VSRs that are inactive or hibernating would not be excluded from the calculations under clause 3.15.9(e) of the NER and the relevant VSRPs will be subject to RERT costs.

B.3 The draft rule includes a time-limited incentive payment in case we fail to secure another payment source

As outlined in section 3.3, there are significant expected benefits to the market from having VSRs participating in dispatch, with limited private incentives. The Commission's first preference is for an additional short-term incentive to be provided through ARENA or a government scheme, to support participation of VSR. However, in the instance that funding through government schemes

170 See clause 3.15.9 (e) of the draft rule.

171 IES, Benefit analysis of improved integration of unscheduled price-responsive resources into the NEM, June 2024, pp. 12-13.

172 AEMO, Reliability and Emergency Reserve Trader.

173 AEMO, Reliability and Emergency Reserve Trader.

174 See clause 3.15.9 of the draft rule.

175 See clause 3.15.9(e) of the draft rule.

or ARENA is not available, the Commission considers that an incentive scheme in the NER, with dollar and time limits, is in the long-term interests of consumers.

B.3.1 A tender mechanism is the most appropriate form of incentive

The Commission is of the view that a simply designed tender process is the most preferable mechanism to deliver incentives for VSRPs in the NER in the short term. Of the possible incentive mechanism designs, two options were identified as having the greatest potential for successful implementation, namely a participant cost recovery mechanism and a tender process.

In a participant cost recovery mechanism, AEMO or the AER would attempt to estimate the efficient costs of a VSRP to participate in dispatch, and participants would then be able to elect to participate and be awarded these amounts. This would allow intending VSRPs to recover some of their establishment costs to participate in dispatch. However, initial investigations into the costs of participating revealed estimating these costs would be extremely challenging. For example, the efficient costs are likely to vary significantly:

- between different underlying resources such as between a household-based VPP and a small group of community batteries
- between participants such as between a gentailer and a large customer.

The alternative approach is a tender process. In this option, potential VSRPs would bid in their own costs into a tender process, and the lowest cost tenders are awarded contracts and payment. This option eliminates the need for cost estimates by revealing likely costs through bidding by participants. To ensure the mechanism remains in the long-term interest of consumers, the draft rule includes a price cap in the mechanism. The price cap would be linked to the expected market benefit of additional participation in dispatch. While a tender process would necessarily result in some administration and implementation costs to both the mechanism operator and to participants preparing tenders, this approach would:

- ensure the market benefit is maintained
- target the lowest cost participants to be engaged first
- allow for some flexibility to adjust to market conditions.

As such, the incentive tender process is the Commission's preferred mechanism, if a mechanism is to be included in the rules.

B.3.2 The draft rule includes a tender mechanism with these features

There are several possible designs for a tender mechanism; each would have slightly different impacts on participation, mechanism outcomes, and the relative market benefit that remains for consumers. We have considered these in developing the incentive mechanism in the draft rule. Key design elements of the mechanism in the draft rule are set out below.

Operation of the incentive mechanism

AEMO would operate the tender process.[176] AEMO has extensive experience in procuring contracts for services, including the RERT, System Restart Ancillary Services, Network Support and Control Ancillary Services, and will enter into transitional services contracts under the *Improving Security Frameworks for the Energy Transition* rule. Additionally, AEMO currently runs a range of auction processes, including the Settlement Residue Auctions, the Victorian Distributed Wholesale Gas Market Capacity Credit Auctions and the Day Ahead Auction in the East Coast gas market.

176 See clause 3.10A.4 (b) of the draft rule.

We consider it likely that an annual tender process would better maximise participation. Having more than one round of tenders is intended to allow greater participation from a diverse set of resources. Annual processes would create regular opportunities for participants of varied maturity levels to prepare and provide offers. This would also enable more opportunities for less mature participants to learn from the experience of more mature participants who provide offers in early rounds.

However, the Commission recognises there is also value in allowing AEMO some flexibility in when it runs the tender process. There may be reasons to not run a tender in a particular year. For instance, if a government scheme is introduced that requires resources to be scheduled in order to receive funding. Alternatively, if in one year there is a highly competitive tender process with a variety of resources across all jurisdictions, it may be in the interest of consumers to procure more in that year and defer running the tender process in the following year.

To accommodate both considerations, the draft rule provides AEMO with some flexibility as to how it runs the tender process, but does require a minimum of two tender processes over the five-year incentive period (proposed to be 2027-2031).[177]

The details of the incentive mechanism processes and contract requirements would be set out in AEMO procedures.[178] AEMO must consult with industry to determine the specifics in the procedures. Under the draft rule, the procedures would be required to cover a range of details including the:[179]

- eligibility criteria for the tender process
- assessment criteria for the tender process
- procedures for conducting the tender process
- timing of the tender process
- offer requirements
- procedures and timetable for participation payments
- requirements of any standard participation agreements, including clarifying the consequences for non-compliance with the agreement.

AEMO would publish this procedure by 5 November 2026 to allow sufficient time for participants to prepare their offers for the first tender process, expected to occur in 2027.[180]

The Commission is conscious that AEMO will incur some costs in delivering the tender mechanism. We are interested in understanding the extent of these costs, and how they can be minimised in the final rule and AEMO's implementation plans.

Objective of incentive mechanism

The primary objective is to maximise the benefits to the market from having additional participation of VSR in dispatch, whilst minimising the cost of payments made to successful tenderers.[181] While there are many potential benefits to the industry and market from having additional participation in dispatch, the draft rule explicitly includes the benefits of:[182]

177 See clause 3.10A.4 (b) of the draft rule.
178 See clause 3.10A.4 (d-g) of the draft rule.
179 See clause 3.10A.4(e) of the draft rule.
180 See clause 11.[XXX].3(a)(3) of the draft rule.
181 See clause 3.10A.4 (a) of the draft rule, definition of *VSR incentive objective*.
182 See clause 3.10A.4(a) of the draft rule, definition of *VSR Benefits*.

- avoided generation — the reduction in costs from generation that would not need to be dispatched due to the contracted VSR in dispatch
- reduced system security service costs — the cost reduction from having lower FCAS costs from having more VSR scheduled
- reduced RERT costs — reduced costs from having more scheduled capacity where this can reduce RERT activation costs
- avoided emissions — reduced emissions from having additional VSR in dispatch (noting that this would be valued using the value of emissions reduction nominated by energy ministers, as published in our guide on the national energy objectives).

The draft rule does not include the benefits of lower wholesale and FCAS prices in the calculation of VSR benefits. This is because these price reductions are a wealth transfer, which are excluded from NEO considerations, as raised in Chapter 4.

In addition to the explicit benefits, AEMO is to account for three considerations in assessing underlying resources supporting an offer.[183] Two of these considerations are consequential to the objective of maximising market benefit, specifically:

- **The relative availability of the resource.** Not all resources will have the same characteristics — some resources are seasonal in nature, while others might have a lower capacity factor, yet these resources may still be of benefit to the market if they are scheduled. As such, instead of excluding participants that plan to regularly hibernate from the tender process, the draft rule requires AEMO to consider the relative availability of the resource when it is considering tender offers.
- **The relative price-responsiveness of the resource.** Resources that are able to participate actively in dispatch, changing their consumption or generation on a regular basis in response to normal variations in spot prices, would likely provide greater market benefit than resources that only change their behaviour at the extremes. For example, a battery that responds to changing market conditions each day will likely provide greater market value than a stable load that only changes its behaviour when the wholesale price reaches the market price cap.

The final consideration speaks to the broader intention to build capacity across the market, namely:

- **The variety of resource types participating as VSRs.** As noted earlier, one of the key drivers of this incentive mechanism is to build capability across the market in the early years after the VSR option becomes available. As part of this, there is benefit from having a diversity of resource types participating (for example, not just 4MW batteries). This would assist in building the ability for more diverse resource types to participate as scheduled participants once the incentive scheme ends. Further, having a diversity of resource types in dispatch could have benefits of greater reliability across a range of market conditions, and lead to more competition in dispatch.

Offer details

Offers into the tender process would be done on a capacity basis, that is the number of MW (not MWh) of the resources that would be scheduled for the length of the contract.[184] Contract length would be set at between one and three years.[185] The trade-off is that a single-year contract would only secure the participation of the VSR for a shorter period, while a longer contract could include

183 See clause 3.10A.4 (f) of the draft rule.

184 See clause 3.10A.4 (e)(4) of the draft rule.

185 See clause 3.10A.4(k)(2) of the draft rule.

inflated numbers to cover the risk associated with a longer time period. Introducing a range of one to three years for contract length seeks to assist AEMO in balancing these competing considerations.

Once a contract has been awarded, the resource underwriting the offer would not be eligible to offer into the tender process again.[186] For example, if a FRMP has a NMI that it offers into the tender process and is successful, the FRMP won't be able to submit an offer including that same NMI in a future tender process. As noted above, one of the drivers of the incentive mechanism is to support participants in recovering some of their initial establishment costs through participation payments. By limiting a single contract per resource, participants would be able to provide offers for their establishment costs, with the view of setting their ongoing operational business case to be sustained on the other market incentives.

A successful tenderer who does not comply with the participation requirements specified in its contract will face consequences as detailed in the contract. For example, if a successful tenderer offers to participate in the market year-round with no hibernation periods and then, in practice, only offers availability for a short period over the year, it will likely be in breach of the contract terms. As such, it will face consequences that could include cancellation of future incentive payments, a requirement to repay part of the payments it has already received, or other penalties. The details of these consequences will be set out in the contract. This is aligned with current practice for other AEMO system service contracts such as RERT.

Participation prices are intended to be confidential to reduce gaming

We propose that the tender process is closed. A closed, or 'sealed offer' tender process means the price per MW of successful offers is kept confidential. As the tender process would be reoccurring over the five-year period, a closed tender process would assist in developing an efficient level of information asymmetry. Limiting information about the other tender participants, the level of competition in the tender process, and clearing prices would reduce the ability to game the tender process by making offers just below the price cap.

Tender price cap

The tender process would adopt a price cap or ceiling that limits the dollars per MW that AEMO would pay under a participation agreement.[187] Without a price cap, AEMO could be obliged to fund high cost projects, which may outweigh the overall benefit to consumers of having the additional participation in dispatch. As such, the draft rules require AEMO to determine the dollars per MW benefit of having an additional MW of participation in dispatch — that is the point where an incentive payment is at parity with the social benefit that MW generates. AEMO would use half this figure as the functional price cap when clearing the tender process.

For example, the IES modelling conducted to support this draft determination estimates the social benefit of having more VSR in dispatch. This modelling explored the same categories of benefits included as VSR Benefits in the draft rule, i.e. reduced generation costs, reduced FCAS costs, reduced RERT costs and reduced emissions. AEMO could draw on this modelling when determining the VSR Benefits in the first instance. Alternatively, if AEMO:

- considers that market conditions have sufficiently changed
- is interested in detailed exploration of jurisdictions or sub-regions, or
- is simply interested in a new modelling approach,

186 See clause 3.10A.4 (e)(1) of the draft rule.

187 See clause 3.10A.4 (a) of the draft rule, definition of *incentive MW price cap*.

it has the option of conducting new modelling to support a more accurate assessment. Using half the VSR Benefits as the MW price cap ensures that consumers would capture a significant portion of the benefit from having the additional participation in dispatch, and should more than offset the cost of paying the incentive payments.

The price cap would be kept confidential during the incentive period, and only communicated to the AER and the AEMC to inform internal analysis of the incentive program.[188] Keeping the price cap confidential would also assist in keeping offers more accurate and cost reflective, minimising the risk of gaming offers.

Overall incentive payment cap

The draft rule includes a payment cap, or total incentive budget, to provide boundaries on the total amount that can be paid over the five-year incentive program. Introducing an overall budget for the five-year incentive program would:

- cap the overall incentive payments faced by consumers
- establish market expectations for the incentive mechanism
- assist AEMO in scoping out the number of contracts to be purchased through tender processes.

There is no single optimal approach in determining the payment cap. Instead, the following information has informed our decision:

- Customer Impact — One relevant factor is what the 'cost' to end consumers would be for the life of the project. Note that the market benefit requirement of the incentive price cap would ensure these costs are outweighed by cost reductions elsewhere in the market. However, based on around nine million NMIs (roughly equivalent to customers) in the NEM today, adding an additional cost of $1 per customer per year would be equivalent to a $45m payment cap.
- Market Benefit — Another consideration is to explore the expected market benefit over the five years the tender process would operate. In IES's low uptake scenario, the social benefit from the first five years is around $167m. Applying the 50%, akin to everyone providing offers at the incentive price cap, the total market benefit would be around $83.5 million.
- Participant cost — A final input is the likely costs to be covered and how many projects could be funded under the tender process. Based on a recent study by GHD for the Commission the upfront costs of a new scheduled generator to set up:[189]
  - forecasting systems range from $5,000-$30,000,
  - generation management system ranges from $90,000-$340,000 and
  - SCADA system ranges from $700,000-$1,000,000 (noting most VSRPs would be expected to use SCADA-lite which would have substantially lower generation management and SCADA costs).

  If it is assumed that on average set up costs are around $250,000- $500,000, then a revenue cap of $50m could fund 100 - 200 participants.

Based on these inputs, we propose that a VSR payment cap is set at $50m over the five-year incentive period.[190]

188 See clause 3.10A.4 (i) of the draft rule.

189 GHD Advisory, Assessment of scheduling costs: Final report, June 2021.

190 See clause 3.10A.4 (g)(2) of the draft rule.

Contract payments and cost recovery

Payments made under contracts between AEMO and successful tenderers would be recovered from Cost Recovery Market Participants. As Market Customers and other energy consumers would likely be the primary beneficiaries of reduced generation costs, reduced FCAS, and reduced RERT costs, they are the preferred group of participants to recover these costs from. The proposed cost recovery equation is set out below, and is aligned with other cost recovery approaches present in the rules today:[191]

$$CRP = \frac{(E_{AC} \times AC)}{\sum E_{AC}}$$

where:

CRP is the amount payable by a Cost Recovery Market Participant for a region for the financial year.

E_{AC} refers to the total adjusted consumed energy by the Cost Recovery Market Participant per region for that financial year. This amount is adjusted and reduced by any energy consumed by a VSR that is currently under contract from the tender mechanism.

Sum of E_{AC} refers to the total sum of all amounts determined as "E_{AC}" in the relevant region for that financial year.

AC refers to the total amount of payments made to successful tender participants over that financial year for that region.

The costs incurred by AEMO to establish and run the incentive mechanism would be recovered from Market Participants through AEMO's usual participant fee processes.[192] Within 40 business days of the end of the financial year, AEMO must determine the total cost of participation payments to be recovered from each year. The commencement of the incentive mechanism would likely align with AEMO's next participant fee determination process, which would assist in integrating these additional costs.

B.3.3 The incentive mechanism will run between 2027 and 2031 and conclude with a report

The draft rules establish the incentive mechanism as time-limited running for 5 years from 2027 to 2031. Introducing the incentive as time-limited may minimise some of the distortionary effects the incentive creates. For example, a participant who might have sufficient economic incentives to participate in the absence of an incentive might refrain from participating unless they receive an additional incentive. Keeping the incentive time-limited assists places bounds on the structural dependencies created by offering incentives. As noted in section 3.3.6, longer-term changes anticipated in the market would drive participation in the absence of the tender process.

Through the transitional rules AEMO would be required to produce the incentive mechanism guideline by November 2026.

End of incentive period reporting

At the end of the five-year incentive period, AEMO would conduct a report exploring the relative success of the incentive mechanism. Under the draft rule, this report would cover:

191 See clause 3.10A.4(r) of the draft rule.

192 See clause 3.10A.4(o) of the draft rule.

- a summary of the outcomes from the tender processes, including AEMO's opinion of whether the objective of the incentive mechanism was satisfied
- a summary of AEMO's learnings and insights from the incentive mechanism
- an analysis of the participation prices in the incentive mechanism
- an analysis of the types of VSR contracted through the incentive mechanism
- any other information AEMO considers relevant or useful to include.[193]

This report would be a useful input into broader considerations around the future of any VSR incentives moving forward.

193 See clause 3.10A.4 (t) of the draft rule.

C Our new framework to monitor and report on unscheduled price-responsive resources

Section 3.4 provided an overview and described the purpose of the AEMO and the AER reporting functions in the draft rule. This appendix sets out the details of this reporting framework for unscheduled price-responsive resources.[194] In particular, it sets out how:

- AEMO reporting would identify issues and increase operational forecasting transparency (appendix C.1)
- the AER reporting would assess the efficiency implications and costs associated with unscheduled price-responsive resources (appendix C.2)
- our 12-month implementation plan would get reporting in place quickly (appendix C.3)
- we will consider if a visibility market model is warranted if reporting reveals an emerging material problem (appendix C.4).

C.1 AEMO would transparently identify issues with forecasting unscheduled price-responsive resources

The draft rule would introduce an AEMO monitoring and reporting framework with two key elements:

- To monitor and report on the magnitude and impact of unscheduled price-responsive resources on deviations of actual demand from forecast in operational time frames.[195]
- To publish the actions it takes to improve demand forecasting to account for unscheduled price-responsive resources. As part of this requirement, AEMO would also publish its methods and assumptions for how it considers unscheduled price-responsive resources in its forecasting.[196]

The draft rule would provide increased transparency on the impact of unscheduled price-responsive resources on market outcomes and how AEMO accounts for these resources in forecasting. Increased transparency of the contribution of unscheduled price-responsive resources to demand forecast deviations and subsequent inefficient market outcomes would be beneficial because:

- <u>It would require AEMO to transparently identify and seek to remedy issues with its demand forecasting to account for unscheduled price-responsive resources</u>. We consider that more transparency on how unscheduled price-responsive resources is considered would be beneficial, particularly as this is expected to grow and influence market outcomes over time.
- <u>It would give market participants a greater understanding of AEMO's operational forecasting</u>. This would provide participants with valuable insights into the specific drivers of the deviations of actual demand from forecasts in AEMO forecasting. These insights would be especially beneficial if a market-based visibility model is introduced in the future as it could give participants insight into the type of quasi-bids that would improve forecasting and lower their FPP.

194 The reporting framework focuses on improving transparency of the impacts that unscheduled price-responsive resources may have on market outcomes which is a defined term in the draft rule. This will not include price-responsive resources that participate in central dispatch.

195 See clause 3.10B.2(b)-(d) of the draft rule.

196 See clause 3.10B.2(b)(5)-(6) of the draft rule.

- It would provide the AEMC with more information to consider the materiality of unscheduled price-responsive resources on market outcomes. It would enable the AEMC to consider the inputs that AEMO has used in demand forecasting (such as the DSP information portal), before changing or increasing the regulatory burden on industry.

This would be distinct from AEMO's current role in publishing forecast errors for reliability reasons that predominantly relate to planning timeframes (such as the ESOO and ISP). This new focus would draw on data to which AEMO already has access, or could request, under NER rules 3.7D and 3.7E.

Our intent is that this would encourage rather than limit AEMO from making changes to its demand forecasting techniques and processes over time. To the extent that AEMO does make changes, this will become evident in the methods and assumptions reporting requirement.

C.1.1 AEMO would measure the impact of unscheduled price-responsive resources and publish trends annually

AEMO would be required to publish a report on its website on an annual basis within three months of the completion of the financial year. This report would analyse the medium-term implications of the issues it monitors. It would also set out the changes AEMO is making to its forecasts to account for unscheduled price-responsive resources to reduce deviations from forecasts. An annual reporting requirement would provide industry with a better overall view of how the forecast deviations change between seasons, at different levels of demand, and over time.

The draft rule specifies topics that AEMO must cover in its reporting, with a requirement for AEMO to publish a guideline outlining how it would fulfil this reporting requirement.[197] When it develops and amends the guideline, AEMO must consult publicly using the Rules consultation procedures. Input from the AER during this consultation process will be important as AEMO's reporting approach would influence or impact the AER's reporting.

This section sets out the AEMO reporting topics included in the draft rule. While the draft rule is principles-based and AEMO would be left to determine metrics, the following information guides stakeholders regarding how we have been thinking about the metrics.

Topic 1A: Summary statistics to identify trends with DER uptake and price-responsive contracts

AEMO would report on the volumes and types of unscheduled price-responsive resources recorded in the DER register and demand side participation information and patterns of their use.[198] We consider this requirement would be a more detailed look at a subset of information already included in AEMO's existing annual reporting requirements.[199] The current rules require AEMO to publish volumes of DER generation information and demand-side participation information on an annual basis, without requiring an analysis of how this is changing over time.

Topic 1B: Deviations between regional demand forecasts and actual outcomes, and the contribution of specific factors (such as unscheduled price-responsive resources, rooftop solar, etc.) to these deviations

AEMO would report on regional demand forecast deviations and the reasons for them at a range of price thresholds.[200] For the analysis of forecast deviations, the period of interest is pre-dispatch and dispatch. Pre-dispatch forecasts are prepared up to 36 hours ahead of the dispatch interval.

197 See clauses 3.10B.2(e) and (f) of the draft rule.

198 See clause 3.10B.2(b)(1)(i)-(ii) of the draft rule.

199 See NER rules 3.7D and 3.7E, the demand side participation information portal and the DER register.

200 See clause 3.10B.2(b)(1)(iii) and 3.10B.2(b)(3)-(4) of the draft rule.

Dispatch forecasts are used to issue dispatch instructions and set spot prices. Given AEMO's different approaches to dispatch and pre-dispatch forecasts, the methodology AEMO may use to fulfil this reporting obligation for those periods could be different.

We note that determining the contribution of unscheduled price-responsive resources to a regional demand forecast deviation will be challenging for AEMO.[201] Electricity demand can deviate from forecasts for a wide range of reasons, such as variations in solar output or price response, and disentangling the reasons is challenging. For dispatch, this can be especially challenging because the regional demand forecast is currently conducted using persistence forecasting which means that dispatch forecasts and dispatch instructions are largely determined based on the demand in previous dispatch intervals.

We expect AEMO to use best endeavours to fulfil this reporting requirement. We expect AEMO will progressively develop more sophisticated techniques to conduct this analysis over time in proportion to the scale of the problem and their experience. AEMO will also need to consider how to best provide accurate and timely information to the AER (discussed in appendix C.4).

We consider analysis of demand forecast deviations and the reasons for them at certain price thresholds will be key to determining patterns of unscheduled price-responsive resources. This is because we anticipate that unscheduled price-responsive resources may respond at very high and very low prices or during different seasons. It will also be essential to support the AER's work to determine market impacts. Therefore, as part of developing its reporting guideline with respect to this topic, we expect AEMO would consult with the AER to determine relevant price thresholds and publish them as part of the reporting guidelines.

Topic 1C: Analysis to identify the contribution of deviations from forecast demand to ancillary services costs using frequency performance payments

AEMO would report on how forecast deviations due to unscheduled price-responsive resources contributed to higher ancillary service costs and frequency performance payments (FPP).[202] We consider an analysis of FCAS would be critical to determine whether the inefficiencies associated with not accounting for unscheduled price-responsive resources are increasing. In particular:

- **FPP**. The rules on FPP will take effect in 2025. While not yet in effect, increasing FPP allocations for FRMPs could be a flag for the inefficiencies of not accurately accounting for unscheduled price-responsive resources in regional demand forecasts. While we have given AEMO flexibility to determine the specific metrics, we consider it could be useful for AEMO to consider the following.
  - The magnitude of FPP due to scheduled vs. unscheduled resources to help determine whether the issue is increasing over time for unscheduled resources.
  - The magnitude of the 'noise' and 'flat' components as described in our visibility market model published alongside the draft determination.[203] Theoretically, the 'flat' component of FPP would be systematic and predominantly due to unscheduled price-responsive resources. Therefore, analysis and publication of the 'flat' and 'noise' components of FPP could be an effective way to determine if unscheduled price-responsive resources are negatively impacting market outcomes.

201 We consider reporting on ST PASA timeframes is not necessary as ST PASA does not include forecast prices and AEMO does not typically use RERT based on an ST PASA lack of reserve level 2 or 3 (LOR2/3). All other forecasts (MT PASA, Energy Adequacy Assessment Projection (EAAP), ESOO, and ISP) cover planning timeframes, which are not relevant for this rule change.

202 See clause 3.10B.2(b)(2) of the draft rule.

203 Creative Energy Consulting prepared for AEMC, *A Market Design to integrate Demand Response into NEM Pricing and Dispatch*, 25 July 2024.

- **Regulation FCAS enablement quantities and the utilisation of that enablement**. Our analysis indicates that AEMO may be required to use more regulation FCAS if material dispatch forecast deviations emerge. This is because AEMO would have higher forecast errors and therefore increase the amount of regulation FCAS it enables to manage this uncertainty. AEMO currently does not report on the costs associated with FCAS enablement quantities from not accurately accounting for unscheduled price-responsive resources in dispatch forecasts and therefore using more FCAS than necessary. Similarly, AEMO does not report on how much of the FCAS enablement is used.

Topic 1D: The extent to which accounting for unscheduled price-responsive resources has helped or hindered demand forecasting in operational timeframes

AEMO would be required to publish information about how it accounts for unscheduled price-responsive resources in its dispatch and pre-dispatch regional demand forecasts.[204] The purpose of this reporting topic is to increase transparency of how AEMO accounts for unscheduled price-responsive resources in its forecasting. This was an issue raised in stakeholder submissions to the consultation paper.[205]

Currently, AEMO is required to describe in general terms how it uses demand side participation information to inform its forecasts.[206] The draft rule would increase transparency on how unscheduled price-responsive resources are used in operational time frames and the specific limitations AEMO experiences with that data. The draft rule would require AEMO to report on the following issues annually:

- The methodologies AEMO uses to account for unscheduled price-responsive resources in its regional demand forecasting for pre-dispatch and dispatch timeframes.[207]
- Any changes it made to its regional demand forecast methodologies for the pre-dispatch and dispatch timeframes and the level of success of the changes in reducing regional demand forecast deviations associated with unscheduled price-responsive resources.[208] This could also include any changes that AEMO is considering in the future to address demand forecast deviations, particularly deviations due to unscheduled price-responsive resources.
- Any barriers AEMO is experiencing with improvements to regional demand forecasts in operational timeframes.[209]

AEMO must set out how it will meet the above obligations in its unscheduled price-responsive resources reporting guidelines.[210] The Commission's intention is to increase transparency and availability of information and analysis of issues associated with unscheduled price-responsive resources, relating to operational demand forecasting. AEMO remains able to publish more information on its broader forecasting processes if it wishes, as part of this work or separately.

204 See clause 3.10B.2(b)(7) of the draft rule.
205 Submissions to the consultation paper, CS Energy, p. 3, EUAA, p. 3.
206 NER rule 3.7D(d).
207 See clause 3.10B.2(b)(7)(i) of the draft rule.
208 See clause 3.10B.2(b)(6) of the draft rule.
209 See clause 3.10B.2(b)(7)(ii) of the draft rule.
210 See clause 3.10B.2(f) of the draft rule.

C.1.2 AEMO would publish quarterly statistics

The annual reporting on the four topics outlined above would be core to AEMO's reporting framework. However, an annual approach alone would come with a significant lag to update industry on market outcomes. Therefore, under the draft rule AEMO's annual reporting framework is supplemented with the requirement to publish statistics on its website on a quarterly basis.

For each of the above topics discussed in appendix C.1.1, AEMO must publish relevant statistics on its website on a quarterly basis.[211] AEMO would be required to consult with stakeholders as part of developing the reporting guidelines to determine what metrics and format of publication would be most beneficial for industry. The purpose of the quarterly statistics would be to provide more regular information to industry and market bodies.

C.2 The AER would assess efficiency and costs annually

The draft rule creates a new reporting requirement for the AER to periodically consider the impact of unscheduled price-responsive resources on efficiency in the wholesale market. This requirement would build upon the AER's current role to monitor and report on effective competition and market efficiency set out in the NEL.[212] The AER would be required to consider the types of inefficient outcomes and costs associated with demand forecast deviations arising due to unscheduled price-responsive resources in the market. The AER would make recommendations based on its findings.

The AER reporting framework is likely to deliver the following benefits:

- increased transparency of the contribution of unscheduled price-responsive resources to demand forecast deviations and subsequent inefficient market outcomes
- increased transparency on the costs and implications of not accounting for impacts of unscheduled price-responsive resources on market outcomes.

C.2.1 The AER would assess costs and efficiency implications, and publish a report annually

The AER would be required to report annually, with the report to be published within six months of the end of the relevant year.[213] This reporting function would provide a longer term view of the costs and impacts of demand forecast deviations caused by unscheduled price-responsive resources.

The AEMC's benefits modelling revealed that demand forecasting deviations cause a series of inefficient outcomes including inefficient prices and dispatch.[214] Our benefits modelling found there are five key areas where unscheduled price-responsive resources could cause inefficient outcomes, leading to higher costs for all energy consumers, as well as higher emissions.

Under existing processes, AEMO produces a price inelastic demand forecast for every dispatch interval. Figure C.1 demonstrates the outcomes in dispatch costs, prices and security, when unscheduled price-responsive resources respond to prices in a dispatch interval.

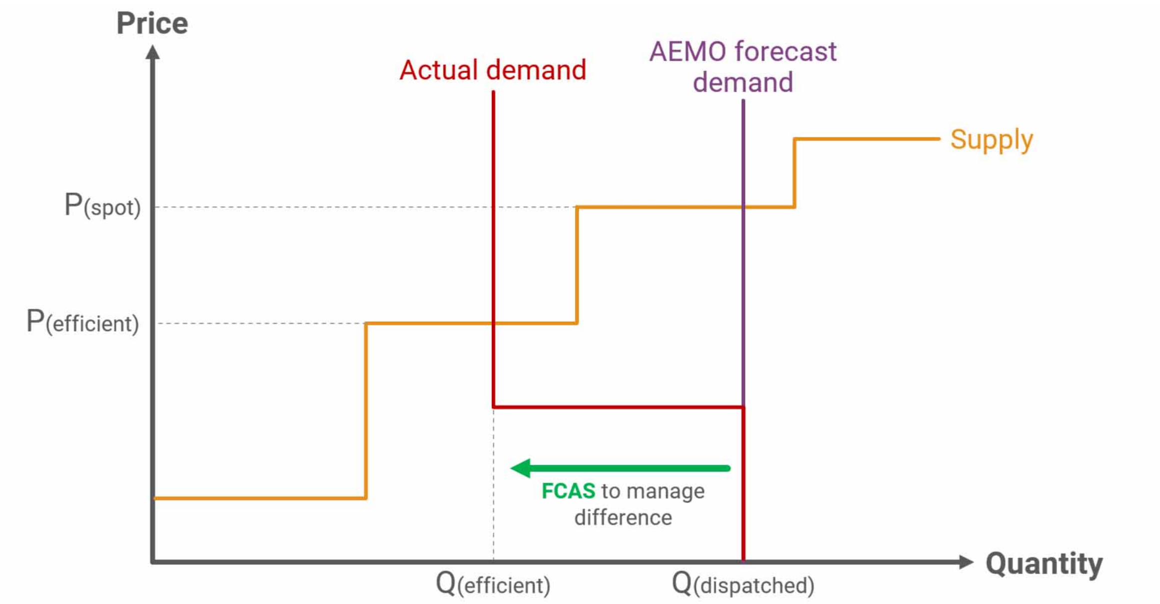
211 See clause 3.10B.2(c) of the draft rule.

212 NEL Part 3, Division 1A.

213 See clause 3.10B.3(b) of the draft rule.

214 In February 2024, we published IES modelling on the 'size of the prize' with further modelling results published alongside this draft determination.

Figure C.1: Inefficient market outcomes from unscheduled price-responsive resources



Source: AEMC

As AEMO does not know the intentions of these resources, it forecasts demand to require $Q_{(dispatched)}$ and uses generator bids to achieve this level of supply. This results in a price point of $P_{(spot)}$. However, where there are unscheduled price-responsive resources that will reduce their consumption or increase generation at this price point, actual demand will be $Q_{(efficient)}$ and the efficient price would have been $P_{(efficient)}$. To balance supply with the actual demand level, frequency control ancillary services (FCAS) are required.

This results in the following market outcomes:

- inefficiently high spot prices which resulted in scheduled resources being paid more than is necessary
- unnecessary costs were incurred by scheduled resources to meet the forecast demand which was higher than actual outcomes (noting that this category of cost is not entirely separate from the point above)
- market ancillary service costs are incurred to bring supply and demand back into balance
- likely higher than necessary emissions because there is a close correlation between high marginal cost generators and high emissions generators
- RERT use and associated costs, especially in circumstances where demand and supply conditions are particularly tight.

The draft rule sets out these five topics for the AER to consider with the requirement for the AER to publish a guideline outlining how it will fulfil this reporting requirement. While the rules are principles-based and the AER will be left to determine metrics, the following information sets out our thoughts on how each topic could be considered.

Topic 2A: Inefficient spot prices as a result of regional demand forecast deviations from unscheduled price-responsive resources

The AER would report on the increased amounts paid to scheduled market participants that provide electricity into the wholesale market (generators, IRPs and Demand Response Service Providers (DRSPs)) due to inefficiently high spot prices resulting from demand forecast deviations.[215] To prepare this analysis, the AER could consider the size of the forecast deviation due to unscheduled price-responsive resources and compare that against price sensitivities. This would enable the AER to determine a counterfactual price and quantity which, multiplied together, would identify the higher revenues paid to generators and other relevant market participants from consumers.

Topic 2B: Inefficient costs incurred by scheduled market participants as a result of regional demand forecast deviations

The AER would report on the increased costs incurred by market participants that provide electricity into the wholesale market due to over-dispatch as a result of demand forecast deviations.[216] To prepare this analysis, the AER could consider the individual generating, storage and demand response assets that were issued dispatch instructions because AEMO was unable to account for unscheduled price-responsive resources. The AER could then multiply this inefficient dispatch of certain assets against their costs to provide electricity into the wholesale market.

Topic 2C: Increased market ancillary service requirements as a result of regional demand forecast deviations

The AER would report on the increased market ancillary service requirements and FPP allocations due to demand forecast deviations.[217] To prepare this analysis, the AER could consider the FPP allocations, FCAS enablement and the proportion that is utilised as discussed in AEMO topic 1C in appendix C.1.1.

Topics 2D: Increased emissions as a result of inefficient generation

The AER would report on increased emissions as a result of inefficient dispatch (topic 2B) and increased ancillary service requirements (topic 2C).[218] To prepare this analysis, the AER could consider the emissions intensity of the marginal generator, drawing on the emissions factors published by AEMO under clause 3.13.14, or could apply a standard intensity factor by asset type, and then multiply the tonnes of additional emissions by the agreed value of emissions reductions.

Topic 2E: RERT use and associated costs as a result of inefficient generation use

The AER would report on the increased amounts paid to RERT providers for inefficient RERT use as a result of demand forecast deviations.[219] To prepare this analysis, the AER could consider the size of the forecast deviation due to unscheduled price-responsive resources and compare that against RERT use at the same time (if relevant). If RERT was activated during this time, the AER would be required to consider the costs associated with RERT and its impact on the counterfactual demand and price levels. However, unlike the above topics, RERT is triggered based

215 See clause 3.10B.3(c)(1) of the draft rule.

216 See clause 3.10B.3(c)(2) of the draft rule.

217 See clause 3.10B.3(c)(3) of the draft rule.

218 See clause 3.10B.3(c)(5) of the draft rule.

219 See clause 3.10B.3(c)(4) of the draft rule.

on pre-dispatch rather than dispatch forecasts. Therefore, the AER may consider instances where a dispatch forecast deviation coincided with RERT use and/or where AEMO used RERT based on a pre-dispatch demand forecast that was materially higher than actual demand.

C.2.2 Relevant data and analysis to support the AER's monitoring and reporting

The reporting framework set out in the draft rule outlines some information that the AER would require for its analysis but does not currently have access to. Therefore, the AER would require additional information and analysis from AEMO to fulfil its reporting requirements. We note that the AER currently has general information-gathering powers which it could use to obtain information from AEMO for this purpose. However, for the reporting function to be effective, the AER should be able to easily access the necessary information.[220] The draft rule makes explicit that the AER can collect information from AEMO to fulfil this reporting obligation.[221] We understand that the AER could develop an ongoing information request for the timely receipt of information from AEMO.

The AER would likely need to collect information from AEMO on several topics to fulfil the reporting obligation. In particular:

- For energy costs,[222] the AER would require:
  - The contribution of unscheduled price-responsive resources to these forecast deviations (this is set out as one of the metrics AEMO would prepare under its reporting functions).
  - More granular price sensitivities to demand changes. This is a key tool that the AER currently uses to determine drivers of differences between forecast and actual price outcomes.[223] However, if the AER is to understand components of demand forecast deviations, sensitivities smaller than the current levels of plus or minus 50MW in some regions may be needed.
  - Detailed information on unscheduled price-responsive resources from the DSPIP and DER register that AEMO receives on a confidential basis.
- For ancillary services costs,[224] the AER would require information to determine the contribution of unscheduled price-responsive resources to the enablement values of market ancillary services. We understand that this information could be on FPP 'flat' and 'noise' components, as discussed above in Topic 1C.

220 We consider that the AER should not require any additional information from market participants to fulfil this function.

221 See clause 3.10B.3(e) of the draft rule.

222 The AER would report on this under NER cl. 3.10B.3(c)(1) of the draft rule.

223 AEMO publishes pre-dispatch price sensitivities for each NEM region. See, Pre-Dispatch Sensitivities, March 2021.

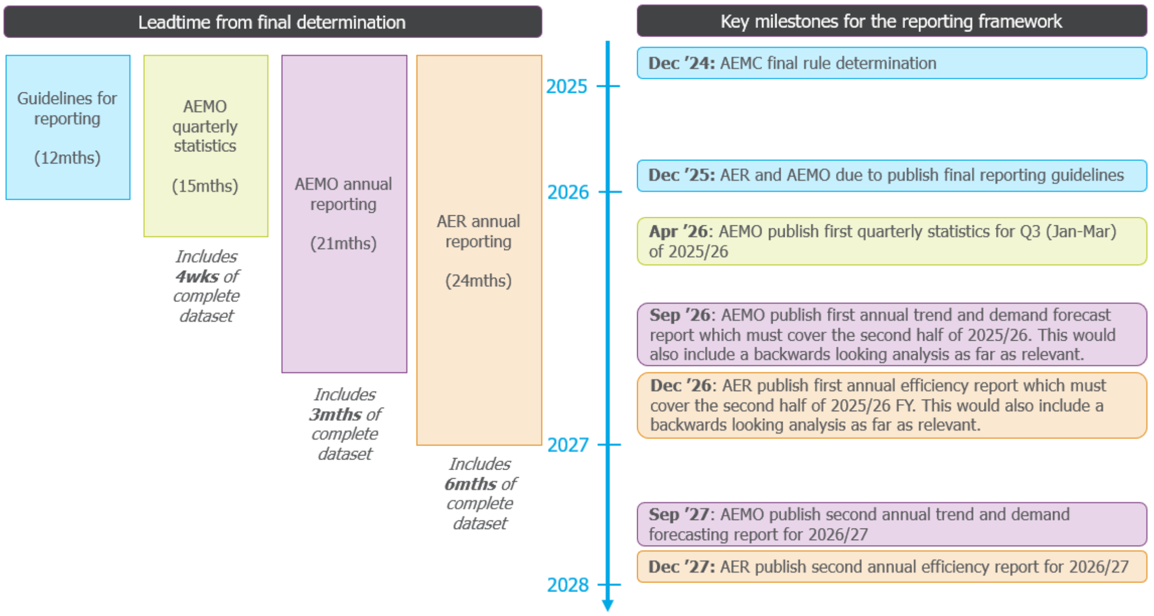
224 The AER would report on this under NER cl. 3.10B.3(c)(3) of the draft rule.

C.3 We propose a 12-month implementation period for the reporting framework

The implementation schedule included in the draft rule for the AER and AEMO monitoring and reporting framework is set out in Figure C.2 below. We consider it is important this reporting framework is in place as soon as practically possible and this has governed our timing requirements. The important elements of this schedule are:[225]

- AEMO publishing its first quarterly statistics following the end of Q3 of the financial year 2025/26 by 1 April 2026.
- AEMO and the AER delivering their first annual reports within three and six months respectively following the end of 2025/26. This would mean that for the first reporting period, each body would only have six months of new data (to the extent that AEMO prepares new data/analysis for this function). However, informed by discussions with AEMO and stakeholder feedback, we consider these first reports should also include a backward-looking analysis for the previous three years (to the extent information is available) to form a sufficient baseline and data set.

Figure C.2: Implementation lead time for AEMO and the AER reporting



Source: AEMC

C.4 We will consider whether a market model for the visibility problem is needed in a later review

The AEMC will consider a longer-term regulatory solution in a review if the inefficiencies associated with AEMO's account of unscheduled price-responsive resources become material. The trigger for this review will be informed by the AER's annual reporting, which will include recommendations to be made to the AEMC.

225 See clause 11.[XXX].4 of the draft rule.

The review should be informed by evidence from AEMO and the AER reports and recommendations. We consider, at this time, there is not sufficient evidence to warrant large regulatory changes or increase burdens on market participants. In the future, should an issue materialise, we could consider the following regulatory approaches which we have consulted on or received stakeholder submissions on throughout this rule change:

- Whether we should implement a model that enables participants to provide visibility information to AEMO. Following stakeholder submissions to the consultation paper, we considered an alternative visibility model. This model was designed to enable market participants to provide information to AEMO to be incorporated into dispatch. We published this model in December 2023 and tested it with the TWG and other stakeholders. Following feedback, we refined this visibility market model and have published an amended detailed design alongside this draft determination.[226] We consider this model would be fit for purpose should the inefficiencies become material as this would drive incentives for participants to provide accurate information to reduce their frequency performance payments.
- Whether we should enhance AEMO's information-gathering powers to collect appropriate information from market participants on unscheduled price-responsive resources. The reporting frameworks by AEMO and the AER should reveal the extent to which AEMO can account for unscheduled price-responsive resources in its forecasting in operational time frames and the way it uses information it currently receives. We received feedback from stakeholders in response to the consultation paper that AEMO could more efficiently collect and use information collected in the DSPIP.[227] We propose to consider the effectiveness of AEMO's information on unscheduled price-responsive resources in the review process. This is because improved reporting would increase transparency and provide evidence of the deficiencies with the current information.

226 Creative Energy Consulting prepared for AEMC, *A Market Design to integrate Demand Response into NEM Pricing and Dispatch*, 25 July 2024.

227 Submissions to the consultation paper, Origin, p. 5, Energy Australia, p. 3, Flow Power, p. 5.

D Key features of the draft rule

This appendix provides an explanation of the draft rule. It is written to assist stakeholders that are likely to engage with the rule drafting. The draft rule has three key elements:

1. **Central dispatch participation by voluntarily scheduled resources:** a new framework to integrate price-responsive resources into central dispatch and scheduling processes. When participating in central dispatch in this way, these resources are termed voluntarily scheduled resources, which reflects both the voluntary nature of participation and that they are scheduled resources. This framework also includes processes for those voluntarily scheduled resources to be temporarily inactive or hibernated for specified periods of time.
2. **VSR incentive mechanism:** is a tender process run by AEMO to incentivise the participation of qualifying resources in central dispatch as scheduled resources by nominating to be a voluntarily scheduled resource. It does so by awarding participation payments to successful participants. A voluntarily scheduled resource is not required to participate in the VSR incentive mechanism. However, it may do so in order to receive participation payments that are in addition to any payments receivable (or payable) in the spot market through participation in central dispatch.
3. **AEMO and AER reporting on unscheduled price responsive resources**: new monitoring and reporting requirements on AEMO in relation to the impacts of unscheduled price responsive resources on forecast deviations in pre-dispatch and dispatch. On the AER in relation to the impacts of unscheduled price responsive resources on the efficiency of the market.

The following sections describe the key features of these three elements of the draft rule by discussing:

- registration, classification and nomination
- processes, requirements and the effect of aggregation of voluntarily scheduled resources
- the voluntarily scheduled resource guidelines
- participation of voluntarily scheduled resources in central dispatch
- processes, requirements and the effect of temporary deactivation and hibernation of voluntarily scheduled resources
- the VSR incentive mechanism
- reporting obligations on AEMO and AER in relation to non-scheduled price responsive resources.

D.1 Registration, classification and nomination

Chapter 2 of the NER specifies the requirements for registration and classification. The categories of registration for different types of participants and the associated classifications are largely based on the characteristics of the plant or equipment, or the activities of the registered participant. The draft rule does not change these requirements. The new framework for voluntarily scheduled resources can only apply to a person who is already registered under Chapter 2 and has classified its relevant resources in accordance with the relevant requirements.

The draft rule enables (but does not require) a person who is already registered as a Generator, Integrated Resource Provider or Market Customer in respect of one of the types of qualifying resources specified in the draft rule to apply to AEMO to nominate its qualifying resource as a voluntarily scheduled resource.[228] A Generator, Integrated Resource Provider or Market Customer who has received approval for nomination of a voluntarily scheduled resource is called a Voluntarily Scheduled Resource Provider.

The resources that are defined to be qualifying resources, and therefore able to be nominated as a voluntarily scheduled resource, are the following:[229]

- a market generating unit that is a non-scheduled generating unit,
- a market bidirectional unit that is a non-scheduled bidirectional unit,
- a market connection point that is non-scheduled load, or
- one or more small generating units or small bidirectional units (or any combination) at a small resource connection point classified as a market connection point in accordance with clause 2.2.8).

Therefore, qualifying resources are all resources that would otherwise be non-scheduled, but are participating in the market (i.e. resources at a market connection point). The effect of nominating a qualifying resource as a voluntarily scheduled resource is that it becomes a scheduled resource.[230]

Approval of a qualifying resource as a voluntarily scheduled resource:

- means the Generator, Integrated Resource Provider or Market Customer who nominates their qualifying resource as a voluntarily schedule resource (the Voluntarily Scheduled Resource Provider) must now comply with the obligations imposed on scheduled resources in relation to the voluntarily scheduled resource
- does not change the underlying classification of the qualifying resource as a non-scheduled generating unit, non-scheduled bidirectional unit, non-scheduled load or small resource connection point (as applicable) to be a scheduled generating unit, scheduled bidirectional unit or scheduled load (as applicable)
- does not affect the underlying classification of that resource as a market generating unit, market bidirectional unit or market connection point (as applicable).[231]

In other words, the draft rule does not remove the registration requirement for that Generator, Integrated Resource Provider or Market Customer or change the classification criteria of the qualifying resource. This is why the draft rule uses the terminology of 'nomination' and sets out a process in Chapter 3 rather than Chapter 2. The registration and classification approved under Chapter 2 remain in place. The effect of AEMO's approval to nominate the relevant resource as a voluntarily scheduled resource is to temporarily substitute the Chapter 2 classification while the qualifying resource is participating as a voluntarily scheduled resource.[232]

The obligations on the Generator, Integrated Resource Provider or Market Customer continue to apply. In addition, the person must comply with the obligations of a Voluntarily Scheduled Resource Provider for a voluntarily scheduled resource.

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228 See clause 3.10A.1(a)-(b) of the draft rule.

229 See clause 3.10A.1(a) of the draft rule.

230 See amended definition of *scheduled resource* in Chapter 10 of the draft rule.

231 See clause 3.10A.1(h) of the draft rule.

232 See clause 3.10A.1(h)(2) of the draft rule.

D.2 Processes, requirements and the effect of aggregation of voluntarily scheduled resources

The draft rule allows for the aggregation of multiple qualifying resources.[233] The draft rule defines 'voluntarily scheduled resource' as either a single qualifying resource associated with a NMI, or two or more qualifying resources associated with NMIs that have been aggregated in accordance with clause 3.8.3.[234] Therefore, references to voluntarily scheduled resource throughout the draft rule refer to an aggregated voluntarily scheduled resource where it has been aggregated.

The aggregation process for voluntarily scheduled resources aligns with the existing process for aggregation in the NER, which requires AEMO to approve the aggregation of resources or units for the purposes of central dispatch.[235] The draft rule requires a Voluntarily Scheduled Resource Provider whose qualifying resources have been approved for nomination as voluntarily scheduled resources, and who wishes to aggregate those voluntarily scheduled resources so they are treated as one voluntarily scheduled resource, to apply to AEMO to do so.[236] This means the qualifying resources must first be approved for nomination before they can be approved for aggregation. In practice, the Commission expects AEMO would be able to undertake the nomination approval under clause 3.10A.1 and the aggregation approval under clause 3.8.3 concurrently.[237]

Where two or more voluntarily scheduled resources have been aggregated, AEMO can treat those individual resources as one resource for the purposes of central dispatch. This means that the disparate resources are collectively seen as one DUID for the purposes of bidding and dispatch. However, the draft rule also allows AEMO to impose conditions on the Voluntarily Scheduled Resource Provider, which may include circumstances in which AEMO requires obligations to be met by each individual voluntarily scheduled resource, rather than the aggregated voluntarily scheduled resource.[238]

Where multiple voluntarily scheduled resources have been aggregated, the aggregated voluntarily scheduled resource consists of multiple NMIs.[239] An example of an aggregated voluntarily scheduled resource could be the consumer energy resources associated with the NMIs of a number of small customers. Given customers may switch retailers, the Voluntarily Scheduled Resource Provider (who would be registered as a Market Customer and be the retailer for those small customers) would need to notify AEMO immediately if a NMI no longer forms part of the voluntarily scheduled resource (e.g. because a customer is no longer a customer of the retailer and therefore the Market Customer is not the financially responsible market participant for the market connection point).[240]

The Voluntarily Scheduled Resource Provider also has an obligation to notify AEMO as soon as reasonably practicable, and in any event, within 10 business days of becoming aware that a voluntarily scheduled resource ceases to be a qualifying resource for any reason.[241] For example, this might occur because the characteristics of the plant or equipment change such that it no longer satisfies the requirements for the underlying classification approved by AEMO under Chapter 2 and it would require a change to its classification.

233 Sees clauses 3.10A.1(b) and 3.8.3 of the draft rule.
234 See definition of *voluntarily scheduled resource* in Chapter 10 of the draft rule.
235 See clause 3.8.3 of the NER.
236 See clause 3.8.3(a3) of the draft rule.
237 However, clause 3.8.3 requires the nomination to happen first (even if that is only immediately prior).
238 See clause 3.8.3(b6) of the draft rule.
239 See definition of *voluntarily scheduled resource* in Chapter 10 of the draft rule.
240 See clause 3.10A.1(m)(1) of the draft rule.
241 See clause 3.10A.1(m)(2) of the draft rule.

D.3 The voluntarily scheduled resource guidelines

The draft rule requires AEMO to make the voluntarily scheduled resource guidelines.[242] The guidelines must specify all of the requirements for nominating qualifying resources as voluntarily scheduled resources,[243] the requirements and processes for aggregation of voluntarily scheduled resources under clause 3.8.3,[244] how voluntarily scheduled resources will participate in central dispatch, including the operational requirements they must be able to comply with,[245] as well as the application of zones for participation.[246]

The draft rule also specifies that the guidelines must include a requirement that the Voluntarily Scheduled Resource Provider whose voluntarily scheduled resource is approved for nomination must be the financially responsible market participant for the connection point associated with the voluntarily scheduled resource.[247]

In addition, the guidelines must include a framework for testing the capabilities of qualifying resources prior to nomination.[248] This will enable interested parties to work out whether their qualifying resources might be suitable for nomination before formally applying to AEMO under draft rule clause 3.10A.1.

In developing the guidelines, AEMO must have regard to a number of factors, including:

- minimising the total cost of facilitating participation by voluntarily scheduled resources in central dispatch, and in doing balance the costs of participation for voluntarily scheduled resources in central dispatch
- balancing:
  - the need for operational requirements on voluntarily scheduled resources in central dispatch, but only to the extent reasonably necessary for AEMO to manage power system security and reliability; and
  - the expected level of participation in central dispatch by voluntarily scheduled resources due to these requirements; and
- any other matter determined by AEMO, acting reasonably, and which must be specified by AEMO in the voluntarily scheduled resource guidelines.[249]

AEMO must review the guidelines by 5 November 2029 in accordance with the rules consultation procedures. Outside of this review, it is able to review the guidelines as it sees fit from time to time in accordance with the rules consultation procedures.[250]

D.4 Participation of voluntarily scheduled resources in central dispatch

As noted above, under the draft rule, voluntarily scheduled resources are scheduled resources. The Voluntarily Scheduled Resource Provider is also a market participant. Therefore, the obligations placed on scheduled resources and market participants in the NER apply to Voluntarily Scheduled Resource Providers in respect of their voluntarily scheduled resources. Many of these obligations in the NER are captured because the draft rule amends the Chapter 10 definition of

242 See clause 3.10A.3 of the draft rule.
243 See clause 3.10A.3(b)(1) of the draft rule.
244 See clause 3.10A.3(b)(2) of the draft rule.
245 See clause 3.10A.3(b)(5) of the draft rule.
246 See clause 3.10A.3(c) of the draft rule.
247 See clause 3.10A.3(b)(3) of the draft rule.
248 See clause 3.10A.3(b)(4) of the draft rule.
249 See clause 3.10A.3(d) of the draft rule.
250 See clauses 3.10A.3(e) and 11.[XXX].3(c) of the draft rule.

'scheduled resource' to include voluntarily scheduled resource and amends the definition of 'market participant' to include Voluntarily Scheduled Resource Provider.

However, some specific changes have also been made to the NER by the draft rule to expressly refer to 'voluntarily scheduled resource' where required. Sometimes all scheduled resources have the same obligation in the NER. However, at other times, the obligations are different for different types of units or resources. In the latter case, voluntarily scheduled resources are separately identified so that it is clear whether and if so, how, the obligation applies to the voluntarily scheduled resource.[251]

The most substantial effect of voluntarily scheduled resources being scheduled resources is that the Voluntarily Scheduled Resource Provider participates in central dispatch by submitting dispatch bids for a voluntarily scheduled resource,[252] and then conforming to their dispatch instructions for dispatch.[253] Principally, the draft rule achieves this by amendments throughout rule 3.8.

The draft rule includes a new clause that sets out the consequences of a Voluntarily Scheduled Resource Provider failing to conform to dispatch instructions in relation to its voluntarily scheduled resource.[254] This rule does not apply to inactive voluntarily scheduled resources or hibernated voluntarily scheduled resources. This is because inactive ones are only required to submit bids into central dispatch (but are not dispatched) and hibernated ones do not participate in central dispatch at all.[255] Inactive and hibernated voluntarily scheduled resources are discussed further below.

Voluntarily scheduled resources that successfully participate in central dispatch will contribute to the setting of spot prices.[256] However, voluntarily scheduled resources will not be able to be constrained on under NER clause 3.9.7.

Voluntarily Scheduled Resource Providers who participate in the VSR incentive program receive financial payments to incentivise participation in central dispatch (the incentive program is discussed further below).[257] These payments are in addition to any amounts payable or receivable in the spot market.

A Voluntarily Scheduled Resource Provider may also be directed under NER clause 4.8.9 in relation to its voluntarily scheduled resource.[258]

D.5 Processes, requirements and the effect of temporary deactivation and hibernation of voluntarily scheduled resources

The draft rule sets out a framework for the parties responsible for voluntarily scheduled resources to be able to temporarily deactivate or hibernate a voluntarily scheduled resource.[259] A Voluntarily Scheduled Resource Provider may submit a deactivation request (to become an inactive

251 For example, compare clause 3.8.9 of the NER (which is not amended by the draft rule because it captures market participants which includes VSRPs) and clause 3.8.4 of the draft rule (which has been amended by the draft rule to refer to VSR).

252 See clauses 3.8.2 and 3.8.6 of the draft rule. This may also include rebids under clause 3.8.22 and 3.8.22A.

253 See clause 3.8.23B of the draft rule.

254 See clause 3.8.23B of the draft rule.

255 See clause 3.8.23B(a) of the draft rule.

256 See clause 3.9.1(a)(3) of the draft rule.

257 See clause 3.10A.4 of the draft rule.

258 See clause 4.8.9 of the NER.

259 See clause 3.10A.2 of the draft rule.

voluntarily scheduled resource)[260] or a hibernation request (to become a hibernated voluntarily scheduled resource)[261] to AEMO in accordance with the requirements specified in clause 3.10A.2 of the draft rule.

Deactivation applies for periods of time of between one trading interval and up to 7 days,[262] and allows the Voluntarily Scheduled Resource Provider to have limited participation in central dispatch during that period. In contrast, hibernation applies for periods between 7 days and 18 months,[263] and ceases participation for the Voluntarily Scheduled Resource Provider in central dispatch during that period altogether.

AEMO must specify the information to be included in the request as well as its criteria for accepting and rejecting requests in the VSR guidelines.[264] In its request, the Voluntarily Scheduled Resource Provider proposes a deactivation period or hibernation period, and if approved, these periods become the approved deactivation period and approved hibernation period, respectively.[265]

Under this framework, the person whose voluntarily scheduled resource has been approved as an inactive or hibernated voluntarily scheduled resource remains a Voluntarily Scheduled Resource Provider during the approved deactivation or hibernation period. However, the obligations that apply to that person are those that apply in relation to an inactive voluntarily scheduled resource or a hibernated voluntarily scheduled resource (and not voluntarily scheduled resources generally).

Draft rule clause 3.10A.2(g) outlines the modifications that apply to a Voluntarily Scheduled Resource Provider during those approved periods in which its voluntarily scheduled resource is either an inactive or hibernated voluntarily scheduled resource. More specifically:

- an inactive voluntarily scheduled resource remains a scheduled resource (and is still required to submit dispatch bids) but is not required to conform to its dispatch instructions (i.e. it is not dispatched)[266]
- clauses 3.8.23B. 3.8.22A, 4.8.9 and 4.9.2 do not apply to an inactive voluntarily scheduled resource[267]
- a hibernated voluntarily scheduled resource is not a scheduled resource and none of the requirements applying to scheduled resources apply to a Voluntarily Scheduled Resource Provider in respect of the hibernated voluntarily scheduled resource[268]
- because the Voluntarily Scheduled Resource Provider retains its underlying registration as a Generator, Integrated Resource Provider or Market Customer in respect of the classification of the relevant qualifying resource, the Voluntarily Scheduled Resource Provider must continue to comply with the obligations that apply to a Generator, Integrated Resource Provider or Market Customer in respect of the relevant qualifying resource.

Draft rule 3.8.2B outlines the effect of participation in central dispatch by a voluntarily scheduled resource and when the voluntarily scheduled resource is otherwise recorded as an inactive or hibernated voluntarily scheduled resource.

260 See clause 3.10A.2(b) of the draft rule.
261 See clause 3.10A.2(m) of the draft rule.
262 See clause 3.10A.2(c)(1) of the draft rule.
263 See clause 3.10A.2(n)(1) of the draft rule.
264 See clauses 3.10A.2(i) & (o) of the draft rule.
265 See clauses 3.10A.2(e)(2) and (p)(2) of the draft rule.
266 See clauses 3.10A.1(i)(2) and 3.10A.2(f) of the draft rule.
267 See clause 3.10A.2(g) of the draft rule.
268 See clause 3.10A.1(i)(1) of the draft rule.

Before the end of an approved deactivation period, the Voluntarily Scheduled Resource Provider must submit a reactivation request.[269] If they fail to do so, or if AEMO rejects the reactivation request, the inactive voluntarily scheduled resource is automatically deemed to be a hibernated voluntarily scheduled resource and the Voluntarily Scheduled Resource Provider must then submit a hibernation request in accordance with the requirements for those requests.[270] If the Voluntarily Scheduled Resource Provider fails to do that, then the Voluntarily Scheduled Resource Provider ceases to be a Voluntarily Scheduled Resource Provider and each qualifying resource ceases to be a voluntarily scheduled resource.[271] The underlying registration and classification resumes.

Similarly, before the end of an approved hibernation period, the Voluntarily Scheduled Resource Provider must submit a resumption request.[272] If the Voluntarily Scheduled Resource Provider fails to submit the resumption request, or AEMO rejects the request, then the Voluntarily Scheduled Resource Provider ceases to be a Voluntarily Scheduled Resource Provider and each qualifying resource ceases to be a voluntarily scheduled resource.[273] The underlying registration and classification resumes.

D.6 The voluntarily scheduled resource incentive mechanism

The underlying classification of a qualifying resource as a non-scheduled generating unit, non-scheduled bidirectional unit or non-scheduled load means that they are not scheduled in central dispatch. The draft rule introduces a VSR incentive mechanism to incentivise the participation of qualifying resources in central dispatch as scheduled resources by nominating to be a voluntarily scheduled resource. It does so by awarding participation payments to successful participants. These payments are additional to any payments receivable (or payable) in the spot market.

The mechanism only operates during the incentive period, which is a limited period of five years from 1 January 2027 until 31 December 2031.[274] During the incentive period, AEMO must conduct at least two tender processes to determine which participants will receive participation payments.[275]

AEMO must develop VSR incentive procedures, which must specify a range of matters, including:[276]

- the criteria for participating in the mechanism, which must include a prohibition on participation by a Voluntarily Scheduled Resource Provider who already has been, or is a party to a VSR participation agreement for a particular voluntarily scheduled resource
- the procedures for conducting the incentive mechanism and timing of each tender process
- the requirements for offers submitted by participants
- the assessment criteria and methodology AEMO will use to select successful participants
- the procedures and timetable for settling participation payments
- requirements for the VSR participation agreement.

In order to be eligible to participate in the VSR incentive mechanism, a VSR incentive mechanism participant must be a Voluntarily Scheduled Resource Provider, or someone who is not yet a

269 See clause 3.10A.2(h) of the draft rule.
270 See clause 3.10A.4(k) of the draft rule.
271 See clause 3.10A.4(l) of the draft rule.
272 See clause 3.10A.4(q) of the draft rule.
273 See clause 3.10A.4(l) of the draft rule.
274 See clause 3.10A.4(b) and definition of *incentive period* in paragraph (a) of the draft rule.
275 See clause 3.10A.4(b) of the draft rule.
276 See clause 3.10A.4(e) of the draft rule.

Voluntarily Scheduled Resource Provider but intends to be if it is successful in the mechanism (an intending VSRP).[277] If successful, the Voluntarily Scheduled Resource Provider must enter into a contract (a VSR participation agreement) under which AEMO pays the Voluntarily Scheduled Resource Provider a participation payment, and the Voluntarily Scheduled Resource Provider participates in central dispatch in accordance with the terms of the agreement and any requirements specified in the VSR incentive procedures.[278]

The VSR incentive mechanism must be structured and run by AEMO in a way that achieves the VSR incentive objective, which is to is to maximise VSR benefits by incentivising market participants with qualifying resources to nominate those resources as voluntarily scheduled resources, while minimising the cost of facilitating participation through participant payments.[279] The VSR benefits are the expected benefits to consumers of voluntarily scheduled resources participating in central dispatch, including where the participation results in reduced system security services costs, avoided generation, avoided emissions and reduced RERT costs.[280]

The price paid to a successful VSR incentive mechanism participant (the participation price) must not exceed the incentive MW price cap. The price cap is a price (in $/MW) determined by AEMO that equals half of the VSR benefits (calculated in $/MW) that AEMO expects will accrue from successful VSR incentive program participants participating in central dispatch, in relation to a particular VSR tender process.[281]

AEMO must determine the incentive MW price cap for each NEM region before commencing each VSR tender process and must notify the amount to the AER and AEMC.[282] All three market bodies must keep the incentive MW price cap confidential during the incentive period.[283]

Therefore, no one successful participant can be paid more than the incentive MW price cap under a VSR participation agreement.[284] In addition to the incentive MW price cap, the aggregate of all payments made under all VSR participation agreements (i.e. participation payments) must not exceed a total amount of $50 million.

Following the completion of the first VSR tender process, and annually thereafter, AEMO must publish the aggregate amount of all participation payments payable in each financial year under all VSR participation agreements. This obligation continues for every financial year in which there is an amount payable under a VSR participation agreement.[285] This means that the reporting of payments could extend beyond the incentive period because VSR participation agreements entered into at the end of the incentive period may nonetheless continue until the expiry of their term, which could be up to three years.[286]

There are two main types of costs arising from the introduction of the VSR incentive mechanism:

- AEMO's costs and expenses incurred in establishing, administering and conducting the VSR incentive mechanism, and
- the amounts payable as participation payments under VSR participation agreements.

277 See clause 3.10A.4(a) of the draft rule.
278 See clause 3.10A.4(j) of the draft rule.
279 See clause 3.10A.4(a) for definition of *VSR incentive objective* and clause 3.10A.4(f) of the draft rule.
280 See clause 3.10A.4(a) of the draft rule for definition of *VSR Benefits*.
281 See clauses 3.10A.4(a) and (g) of the draft rule.
282 See clause 3.10A.4(h) of the draft rule.
283 See clause 3.10A.4(i) of the draft rule.
284 See clause 3.10A.4(k)(3) of the draft rule.
285 See clause 3.10A.4(n) of the draft rule.
286 See clause 3.10A.4(k)(2) of the draft rule.

The draft rule requires AEMO to recover the first type from all Registered Participants as part of the fees imposed in accordance with rule 2.11 (i.e. participant fees).[287]

For the second, the draft rule sets out a new cost recovery framework.[288] These amounts are to be recovered from cost recovery market participants in accordance with the formula specified in the draft rule. To the extent a cost recovery market participant is a Voluntarily Scheduled Resource Provider, the formula excludes energy consumed by that provider's voluntarily scheduled resources that are subject to a current VSR participation agreement.[289]

AEMO must determine the amounts in respect of the previous financial year within 40 business days of the completion of that financial year and then include that amount in the next preliminary statement provided to each cost recovery market participant.[290] This links these payments to the settlement processes in Chapter 3 of the NER.

Following the completion of the incentive period, AEMO must publish a report within 12 months that includes a summary of the outcomes from the VSR incentive mechanism, an analysis of the participation prices paid to participants under the VSR participation agreements, as well as an analysis of the types of voluntarily scheduled resources contracted under those agreements.[291]

D.7 Reporting obligations on AEMO and AER in relation to non-scheduled price responsive resources

The draft rule introduces a reporting function on AEMO and the AER to report on the impact that unscheduled price responsive resources have on forecast deviations. Forecast deviations are the difference between forecast load for a particular trading interval developed for pre-dispatch and dispatch, and the actual load during that trading interval. Unscheduled price responsive resources refer to resources that are not a scheduled resource, are capable of changing output or consumption depending on changes in forecast or actual spot prices. They include hibernated voluntarily scheduled resources, but not an inactive voluntarily scheduled resource or a voluntarily scheduled resource.

The draft rule requires AEMO to report on the impact that unscheduled price-responsive resources have on forecast deviations, and the resulting market outcomes.[292] The product of this reporting is two things: an annual report, and quarterly data produced as a source of information that is updated at least quarterly.

By 30 September each year, AEMO must publish a report that covers the previous financial year. The report must include AEMO's analysis of the statistics and trends of:

- the volumes and types of unscheduled price-responsive resources reported by Registered Participants, using the DER register information and demand side participation information[293]
- patterns in the use of unscheduled price responsive resources, to the extent identifiable, in response to forecast and actual spot prices[294]

287 See clause 3.10A.4(o) of the draft rule.
288 See clauses 3.10A.4(p) to (r) of the draft rule.
289 See clause 3.10A.4(r) of the draft rule.
290 See clauses 3.10A.4(p), (r) and (s) of the draft rule.
291 See clause 3.10A.4(t) of the draft rule.
292 See clauses 3.10B.1 and 3.10B.2(a) of the draft rule.
293 See clause 3.10B.2(b)(1)(i) of the draft rule.
294 See clause 3.10B.2(b)(1)(ii) of the draft rule.

- the approximate contribution of unscheduled price-responsive resources to forecast deviations.[295]

The report must also include AEMO's best estimate of:

- the impacts of unscheduled price-responsive resources on forecast deviations in pre-dispatch and dispatch, including in comparison with outcomes published in previous reports [296]
- the impact of unscheduled price-responsive resources on forecast deviations in relation to additional amounts paid to ancillary service providers for the additional ancillary services enabled and to cost recovery market participants for the ancillary service transaction payments made.[297]

The report must include AEMO's identification of additional information or inputs required to improve or account for unscheduled price-responsive resources in load forecasts.[298]

The report must include AEMO's description of:

- any actions taken by AEMO to reduce forecast deviations by accounting for unscheduled price-responsive resources that have resulted in improved market outcomes[299]
- the methodologies used by AEMO to consider and manage the impacts of unscheduled price-responsive resources on load forecasts for pre-dispatch and dispatch[300]
- any barriers to AEMO using those methodologies to improve forecasting.[301]

The annual report must also be supported by a source of information that presents the information and metrics specified by AEMO in its reporting guidelines, and the source of information must be updated when new information becomes available and at least once each calendar quarter.[302] This source could be in the form of a webpage that can be readily updated and accessed by interested parties.

The draft rule also requires the AER to publish a report by 31 December each year that covers the previous financial year,[303] with the objective of providing transparency on the impacts of unscheduled price responsive resources on efficient market outcomes to inform future market reform.[304] The monitoring and reporting framework established by the draft rule is part of the AER's existing wholesale market and monitoring and reporting functions under section 18C of the NEL.

The AER's report must analyse the impact of unscheduled price responsive resources on forecast deviations, and the consequential impacts on the efficiency of the market, including in relation to:[305]

- additional amounts paid to Generators, Integrated Resource Providers and Demand Response Service Providers for different quantities and prices of electricity and wholesale demand response that are dispatched

295 See clause 3.10B(b)(1)(iii) of the draft rule.
296 See clause 3.10B.2(b)(4) of the draft rule
297 See clause 3.10B.2(b)(2)(i)-(ii) of the draft rule.
298 See clause 3.10B.2(b)(5) of the draft rule.
299 See clause 3.10B.2(b)(6) of the draft rule
300 See clause 3.10B.2(b)(7)(i) of the draft rule.
301 See clause 3.10B.2(b)(7)(ii) of the draft rule.
302 See clauses 3.10B.2(c) and (d) of the draft rule.
303 This means it covers the same financial year reporting period as AEMO's report, but it is published three months after AEMO's report, which allows the AER to consider AEMO's report in preparing its own report.
304 See clauses 3.10B.3(a) and (b) of the draft rule.
305 See clause 3.10B.3(c) of the draft rule.

- additional amounts paid to Ancillary Service Providers for additional market ancillary services that are enabled
- Cost Recovery Market Participants for ancillary service transaction payments under clause 3.15.6AA
- additional amounts paid to Registered Participants for RERT for scheduled reserves that are dispatched and unscheduled reserves that are activated
- additional emissions resulting from the relative increases referred to for the previous items.

The report must also identify the trends and outcomes on the efficiency of the market as a result of those matters when compared to previous financial years and the AER's recommendations for how to improve the efficiency of the market in respect of those matters.[306]

The AER may request AEMO to provide information to the AER if it considers it reasonably necessary to satisfy its reporting obligations, including confidential information that AEMO has received from registered participants, and AEMO must comply with any such request from the AER.[307]

The draft rule requires both AEMO and the AER to prepare and publish price responsive resource reporting guidelines, which specify how each will meet their respective reporting obligations.[308]

306 See clause 3.10B.3(c) of the draft rule.

307 See clauses 3.10B.3(e) and (f) of the draft rule.

308 See clauses 3.10B.2(e) and (f) and clauses 3.10B.3(g) and (h) of the draft rule.

E Legal requirements to make a rule

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

E.1 Draft rule determination and more preferable draft rule

In accordance with section 99 of the NEL, the Commission has made this draft rule determination for a more preferable draft electricity rule, and no draft retail rule, in relation to the rule proposed by the proponent.

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

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

E.2 Power to make the draft electricity rule

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

The more preferable draft rule falls within section 34 of the NEL as it relates to regulating the activities of persons (including Registered participants) participating in the national electricity market.[309]

E.3 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the more preferable draft rule
- the rule change request
- submissions received during consultation on the consultation paper
- stakeholder input received at the public forum held on 19 February 2024 and in technical working group meetings held over the period February to May 2024
- the ways in which the more preferable draft rule will or is likely to contribute to the achievement of the NEO
- whether any consequential changes to the National Energy Retail Rules (NERR) were required
- the application of the more preferable draft electricity rule to the Northern Territory.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[310]

E.4 Making electricity rules in the Northern Territory

E.4.1 Application of the draft rule to the Northern Territory

As the draft rule amends some chapters of the NER that apply in the Northern Territory, the Commission has considered how the rule should apply to the Northern Territory according to the following questions:

309 NEL section 34(1)(a)(iii).

310 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.

- Should the NEO test include the Northern Territory electricity systems? Yes. For this rule change request, the Commission's draft determination is that the reference to the "national electricity system" in the NEO includes the local electricity systems in the Northern Territory.
- Should the rule be different in the Northern Territory? No. For this rule change request, the Commission's draft determination is to make a uniform rule for the NEM and the Northern Territory. The key aspects of the draft rule would have no effect in the Northern Territory as chapters 3 and 4 of the NER do not apply in the Northern Territory. However, this does not necessitate making a differential rule.

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.[311] Under those regulations, only certain parts of the NER have been adopted in the Northern Territory.

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

E.4.2 Test for scope of "national electricity system" in the NEO

Under the NT Act, the Commission must regard the reference in the NEO to the "national electricity system" as a reference to whichever of the following the Commission considers appropriate in the circumstances having regard to the nature, scope or operation of the proposed rule:[312]

1. the national electricity system
2. one or more, or all, of the local electricity systems[313]
3. all of the electricity systems referred to above.

E.4.3 Test for differential rule

Under the NT Act, the Commission may make a differential rule if it is satisfied that, having regard to any relevant MCE statement of policy principles, a differential rule will, or is likely to, better contribute to the achievement of the NEO than a uniform rule.[314] A differential rule is a rule that:

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

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

A uniform rule is a rule that does not vary in its terms between the national electricity system and one or more, or all, of the local electricity systems, and has effect with respect to all of those systems.[315]

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

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

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

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

315 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 penalty provisions and conduct provisions

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

The NEL sets out a three-tier penalty structure for civil penalty provisions in the NEL and the NER.[316] A Decision Matrix and Concepts Table,[317] approved by Energy Ministers, provide a decision-making framework that the Commission applies, in consultation with the AER, when assessing whether to recommend that provisions of the NER should be classified as civil penalty provisions, and if so, under which tier.

The draft rule include two new provisions in the NER, which the Commission proposes to recommend to the Energy Ministers' Meeting be classified as civil penalty provisions, as set out below.

Table E.1: NER civil penalty provision recommendations

Clause	Description of clause	Proposed classification	Reason
3.10A.1(l)	This clause requires Voluntarily Scheduled Resource Providers to comply with any terms and conditions imposed by AEMO in respect of their voluntarily scheduled resource during nomination.	Tier 1	Failure to comply with terms and conditions imposed by AEMO may affect AEMO's ability to plan and operate the power system efficiently. This Tiering is also consistent with similar CPPs in Chapter 2 of the NER.
3.10A.1(m)	This clause requires Voluntarily Scheduled Resource Providers to notify AEMO: (1) immediately if the Voluntarily Scheduled Resource Provider ceases to be the financially responsible Market Participant for a voluntarily scheduled resource; or (2) as soon as practicable, and in any event, no later than 10 business days after becoming aware that a voluntarily scheduled resource ceases to be a qualifying resource.	Tier 1	Failure to comply with these notification requirements may negatively impact the relevant customer and the energy market. This Tiering is also consistent with similar CPPs in Chapter 2 of the NER.

316 Further information about civil penalties is available here

317 The Decision Matrix and Concepts Table is available here

Where the draft rule amends provisions that are currently classified as civil penalty provisions, the Commission does not propose to recommend to the Energy Ministers' Meeting any changes to the classification of those provisions.

Abbreviations and defined terms

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
AGC	Automatic Generation Control
BDU	Bi-directional unit
Commission	See AEMC
CER	Consumer energy resource
CIS	Capacity investment Scheme
C&I	Commercial and industrial
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DER	Distributed energy resources
DNSP	Distribution network system provider
DRSP	Demand Response Service Provider
DSO	Distribution system operator
DSP	Demand side participation
DSPIP	Demand side participation information portal
DUID	Dispatchable unit identifier
EAAP	Energy Adequacy Assessment Projection
ESOO	Electricity statement of opportunity
EV	Electric vehicle
FCAS	Frequency control ancillary services
FEL	Flexible export limits
FPP	Frequency performance payments
FRMP	Financially responsible market participant
HLIA	High-level implementation assessment
ICCP	Inter-control centre communications protocol
IES	Intelligent energy systems
IESS	Integrated Energy Storage Systems rule change
IRP	Integrated resource provider
ISP	Integrated system plan
LOR	Lack of reserve
LSU	Light scheduling unit
MASS	Market Ancillary Services Specifications
MCE	Ministerial Council of Energy
MT PASA	Medium term projected assessment of system adequacy
MW	Megawatt
NECF	National Energy Customaer Framework
NEL	National Electricity Law

NEM	National Electricity Market
NEMDE	NEM dispatch engine
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERO	National Energy Retail Objective
NERR	National Energy Retail Rules
NMI	National metering identifier
NPV	Net Present Value
NSP	Network service provider
PASA	Projected assessment of system adequacy
PFR	Primary Frequency Response
Proponent	The individual / organisation who submitted the rule change request to the Commission
RERT	Reliability and Emergency Reserve Trader
SCADA	Supervisory Control and Data Acquisition
SOC	State of Charge
SoTP	Size of the prize (IES modelling)
SRA	Small resource aggregator
ST PASA	Short term Projected assessment of system adequacy
TWG	Technical working group
V2G	Vehicle to grid
VPP	Virtual power plant
VSR	Voluntarily scheduled resource
VSRP	Voluntarily scheduled resource provider
WDRM	Wholesale demand response mechanism
WDRU	Wholesale demand response unit