AEMC

RULE

Australian Energy Market Commission

CONSULTATION PAPER

NATIONAL ELECTRICITY AMENDMENT (INTEGRATING PRICE-RESPONSIVE RESOURCES INTO THE NEM) RULE

NATIONAL ENERGY RETAIL AMENDMENT (INTEGRATING PRICE-RESPONSIVE RESOURCES INTO THE NEM) RULE

3 AUGUST 2023

INQUIRIES

Australian Energy Market Commission
GPO Box 2603
Sydney NSW 2000

E aemc@aemc.gov.au
T (02) 8296 7800

Reference: ERC0352, RRC0051

ABOUT THE AEMC

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

COPYRIGHT

CITATION

To cite this document, please use the following:
AEMC, Integrating price-responsive resources into the NEM, Consultation paper, 3 August 2023

SUMMARY

1 The Australian Energy Market Operator (AEMO) has submitted a rule change request to introduce a 'scheduled lite' mechanism into the National Electricity Market (NEM). The mechanism seeks to integrate non-scheduled price-responsive resources into NEM market scheduling processes. This would increase visibility of the likely actions of these resources, thereby improving the efficiency of the broader system and reducing overall costs for consumers.

2 AEMO's rule change is part of a package of reforms being progressed by the market bodies to realise the benefits of consumer energy resources (CER) for consumers and the system. While this rule change focuses on integrating these resources into NEM market systems it should be viewed alongside the other reforms which seek to:

- **Facilitate uptake, and share the benefits of CER**. The Commission's *Review of the regulatory framework for metering services* will facilitate the uptake of CER. Our *Unlocking CER benefits through flexible trading* rule change will facilitate consumers receiving better offers from retailers for the value that their CER provides.
- **Improve consumer protections for consumers purchasing and using CER**. The Australian Energy Regulator's (AER) *Review of consumer protections for future energy services* will provide advice on if new or different regulation is required to protect consumers with CER services.
- **Ensure the secure and reliable operation of CER**. The Commission's *Review into CER technical standards* will improve compliance with the technical standards for CER devices. This will support secure network and reliable market operation, thereby allowing greater uptake of CER and benefits for consumers.

3 This consultation paper commences the Commission's consideration of the rule change request. We are seeking stakeholders' input on the need to integrate price-responsive resources into the NEM, if the proposed solution efficiently does this or if there are alternative solutions. Stakeholder submissions to this paper are due by 14 September 2023.

What are price-responsive resources?

4 Consumers are increasing their take-up of solar panels, batteries, home energy management systems and electric vehicles (EVs). These energy resources offer consumers the opportunity to have lower energy bills and a greater level of control over their energy use. There are also commercial and industrial resources (for example commercial chillers), and new types of large loads (for example hydrogen electrolysers) which could be price-responsive.

5 Energy service providers (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. When this occurs, these resources are used to help manage network infrastructure, manage energy fluctuations, and assist retailers to reduce their wholesale costs.

6 We refer to these resources collectively as price-responsive resources. AEMO expects that

VPPs will significantly grow as more households and businesses take up flexible resources, to around 1GW by 2025 (double the current amount) and over 4GW by 2030.

Integrating price-responsive resources is important for the energy system and all consumers

7 These resources, and their response to market price signals, are currently not fully integrated into the planning and operation functions in the NEM. 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. Network and wholesale market services could both be provided more efficiently if these resources were fully integrated. Over time, this would reduce the total cost of providing consumers with reliable electricity supply and therefore decrease prices for all consumers.

8 AEMO stated that additional costly large-scale generation, storage and network infrastructure would need to be built to maintain secure and reliable electricity supply in the absence of efficient integration of price-responsive resources. This would have flow-on costs for industry and customers. The cost of market interventions to maintain secure and reliable energy would also be higher.

9 AEMO suggested that duplicating 20 percent of projected coordinated distributed energy resources (DER) storage with shallow grid-scale storage could result in additional costs of around $1.8 billion to 2040. This would likely result in higher costs for consumers. Several studies have demonstrated substantial net benefits from effective integration of these resources, including avoided costs along the electricity supply chain, with associated reductions in consumer costs.

10 The Commission considers that it is important to assess the potential impact of price-responsive resources on specific market outcomes. This paper breaks down the potential benefits of better integrating these resources into AEMO's system planning and management into five categories:

- **dispatch costs in the NEM** — knowing when these resources can be used to reduce demand (particularly at higher cost times), improves demand forecasting and reduces the resources that AEMO dispatches to meet demand
- **energy prices in the NEM** — by better matching supply and demand, the cost of energy would be more efficient, potentially reducing spot prices
- **security of supply in the NEM** — by reducing the need for additional, potentially more expensive generation reserves to balance the market, system security will be achieved at lower cost
- **reliability of supply in the NEM** — the ability to schedule these available resources could improve planning and the use of lower-cost lower-emission generation and lower intervention costs
- **operation of distribution and transmission networks** — longer-term accurate forecasts would improve network investments and planning, reducing network costs to consumers.

The Commission is interested in stakeholder views on what a solution, or solutions, should achieve for the NEM and consumers.

AEMO proposed a mechanism to better integrate price-responsive resources into the market

11 AEMO's rule change request proposes a voluntary mechanism for price-responsive resources to participate in scheduling processes in the NEM. This mechanism has two modes: visibility and dispatch. The modes work together, with visibility as the entry mode, and participants expected to progress to dispatch mode once their capabilities are developed.

- **Visibility mode**: this mode is designed to give AEMO information on the use of unscheduled price-responsive resources, to improve the accuracy of short-term demand and price forecasting. Participants will provide a forecast of generation and consumption called "indicative bids".
- **Dispatch mode**: this mode is designed to integrate unscheduled price-responsive resources into the NEM central dispatch and scheduling processes. Participants would provide bids for their generation and load, and receive and follow dispatch targets. This would be similar to existing scheduled participants but with tailored requirements reflecting the nature of the resources.

12 AEMO's proposal would provide it with visibility of the actions of these resources. This in turn would improve forecasts, dispatch, reliability and security of the electricity market.

13 The Commission is interested in stakeholder views on AEMO's proposal, including the extent to which it is likely to provide the five benefits outlined above, whether significant implementation costs or difficulties would arise, and whether there are improvements or alternative solutions to integrate these resources and allow for better market operation.

Submissions are due by 14 September 2023 with other engagement opportunities to follow

14 This rule change request is a potentially significant reform to the NEM. The Commission understands that it is important to canvass a range of options to develop the right solution. As such we may consider a longer process with additional steps or a technical working group to ensure that solutions and implementation considerations (if the rule change is progressed) are fully examined.

15 There are multiple options to provide your feedback throughout the rule change process.

16 Written submissions responding to this consultation paper must be lodged with Commission by 14 September 2023 via the Commission's website, www.aemc.gov.au.

17 There are other opportunities for you to engage with us, such as one-on-one discussions or industry briefing sessions. See the section of this paper about "How to engage with us" for further instructions and contact details for the project leader.

List of full consultation questions

QUESTION 1: DO YOU AGREE THAT PRICE-RESPONSIVE RESOURCES NEED TO BE INTEGRATED INTO THE NEM?

1. The Commission has identified five types of issues with increasing volumes of price-responsive resources. Do you agree with this breakdown of the issues? What do you consider the magnitude of each issue is? How is this likely to change over time?

QUESTION 2: REPRESENTING PRICE-RESPONSIVE RESOURCES IN SCHEDULING PROCESSES

1. Is participation in this mechanism dependent on whether price-responsive resources can be separated at or behind the connection point (currently being considered through the "Unlocking CER benefits through flexible trading" rule change)? Please explain what impacts separating CER would have on traders' participation in energy markets.
2. Do you have views on the need to define price-responsive resources or the traders that might coordinate a large amount of such resources?

QUESTION 3: VISIBILITY MECHANISM - ENCOURAGEMENT TO PARTICIPATE

1. What are your views on the incentive mechanisms outlined in Table 3.1?
2. Are there any alternative incentives the Commission should consider?
3. Should mandatory participation in the visibility mode be considered?
    a. If so, what types of traders/ resources should be required to participate and what criteria (for example size in a region) or circumstances (observed behaviour or performance) could the requirement to participate be based on?

QUESTION 4: ASSESSMENT OF VISIBILITY MODE

1. Do you think visibility mode would be effective as designed? If not, what improvements or amendments would you suggest and why?
2. Do you agree with the Commission's initial assessment of visibility mode's ability to achieve the outcomes identified?
3. If we progress with this mode, what should the Commission consider in terms of implementation of this mode?
4. Is visibility mode needed as a stepping stone to the dispatch mode?

QUESTION 5: DISPATCH MODE — INCENTIVES TO PARTICIPATE

1. Do you think dispatch mode would be effective as designed? If not what improvements or amendments would you suggest and why?
2. What costs would traders incur to participate in dispatch mode?
3. Is access to the wholesale electricity market and other markets (for example regulation FCAS and PFR) sufficient incentive to participate in dispatch mode?
4. Are there other factors that would encourage or discourage participation in the dispatch mode?
5. Should participation in the dispatch mode be required? If so, what types of traders/resources should be required to participate, against what criteria and in what circumstances?

QUESTION 6: ASSESSMENT OF DISPATCH MODE

1. Do you agree with the Commission's initial assessment of the ability of dispatch mode to address the outcomes identified?
2. If we progress dispatch mode, what does the Commission need to consider in terms of implementation of this mode?

QUESTION 7: OTHER ISSUES RAISED IN RELATION TO THE SCHEDULED LITE MECHANISM

1. Do you consider that the proposed mechanism (or a similar mechanism) should be introduced through a principles-based framework, with the details considered through AEMO's procedures and guidelines?
2. Do you consider that the proposed mechanism (or a similar mechanism) requires changes to the NERR to protect consumers?

QUESTION 8: ARE THERE PREFERABLE ALTERNATIVE ARRANGEMENTS?

1. Are there any alternative solutions that you think would be preferable to AEMO's proposal and more aligned with the long-term interests of consumers? What are the costs and benefits of any proposed alternative arrangement?

QUESTION 9: ASSESSMENT FRAMEWORK

1. Do you agree with the proposed assessment framework? Are there additional principles that the Commission should take into account or principles included here that are not relevant?

QUESTION 10: VISIBILITY MODEL — PARTICIPATION, DATA AND OPERATIONS

1. Would traders be readily able to participate and provide the data as proposed? What implementation considerations and costs would be required to participate?
2. Is there anything the Commission could do in designing the rule that would help to minimize the costs and maximise the benefits?

QUESTION 11: DISPATCH MODEL — PARTICIPATION, DATA AND OPERATIONS

1. Could price-responsive resources comply with the operational and data requirements? If not:
    a. How difficult would it be to change your systems to comply with the requirement outlined above?
    b. Does this depend on what resource is participating?
2. Do the proposed compliance arrangements strike an appropriate balance between the reliability of the response and the barrier to participation?

How to make a submission

We encourage you to make a submission

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

We have included consultation questions in this paper, however, you are welcome to provide feedback on any additional matters that may assist the Commission in making its decision.

How to make a written submission

Due date: Written submissions responding to this consultation paper must be lodged with Commission by 14 September 2023.

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, RRC0051.[1]

Tips for making submissions 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]

For more information you can contact us

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

Project leader:	Rachel Thomas
Email:	rachel.thomas@aemc.gov.au
Telephone:	02 8296 7891

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 is available here: https://www.aemc.gov.au/contact-us/lodge-submission

CONTENTS

APPENDICES

TABLES

FIGURES

1 THE CONTEXT FOR THIS RULE CHANGE REQUEST

This consultation paper seeks stakeholder feedback on the rule change request 'Scheduled Lite mechanism in the National Electricity Market' submitted by the AEMO.[4] The rule change request proposes changes to the National Electricity Rules (NER) to introduce a mechanism integrating price-responsive resources into the scheduling processes.

This chapter outlines AEMO's rule change request, notes interactions with other reforms underway in the NEM and sets out the rule change process we plan to follow to consider this request.

BOX 1: WHAT ARE PRICE-RESPONSIVE RESOURCES?

We use the term 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 solar PV, batteries, EVs, flexible hot water systems and pool pumps. Consumers, or someone acting on their behalf, could adjust how these devices produce or consume electricity in response to network or wholesale market prices, potentially as part of an aggregation such as a virtual power plant (VPP).[1]
  - A high proportion of Australian houses already have solar rooftop PV systems (one in three homes).[2] The majority of rooftop solar PV is not currently directly controllable. However, newer inverter technologies combined with residential batteries, will increasingly allow consumers to control their generation and consumption.
  - Several trials are underway which are showing how these resources can be managed to benefit the grid. For example, AGL, Plus ES and ARENA are trialling the orchestration of hot water systems in South Australia. This will show whether managing hot water systems can help with grid stability and reduce energy prices.[3]
  - AEMO estimates the total capacity of resources currently in VPPs in NEM jurisdictions is around 400MW.[4] Some market participants are already responsible for hundreds of megawatts (MWs), and this figure will grow into gigawatts (GW) in the future.[56]
- 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).

4 AEMO, Rule change request - Scheduled Lite Mechanism in the National Electricity Market. Available here

- small non-scheduled generating units such as backup generators, units that can generate electricity from production byproducts and bidirectional units, such as community batteries that are below 5MW.[7]

Importantly, we are focused on the energy service providers (retailers and aggregators) that operate the resources on consumers' behalf. Residential and small consumers using their resources for their own use are not the focus of this rule change request.

These resources represent a growing amount of generation and controllable load for the energy grid. AEMO expects that by 2050 they will make up 40% of the generation in the NEM.[8]

Larger non-scheduled generators and loads can opt-in to existing wholesale energy market-facing mechanisms. For example, they can apply to be scheduled loads or partake in the wholesale demand response mechanism (WDRM). Throughout this consultation paper, we primarily focus on price-responsive resources that do not currently use one of these schemes. However, we note that participants using, or eligible to use, these schemes might choose to use any mechanism implemented in this rule change request. We also note that once we have developed a preferred position on this rule change request, we will also assess if consequential changes to the rules governing these existing schemes are likely to be in the long-term interests of consumers.

Source: 1 AEMC, The potential to move to a two-sided market, 20 April 2020, available here. 2 Department of Climate Change, Energy the Environment and Water, Solar PV and batteries, accessed on 20 July, available here. 3 ARENA, '*Dynamically managing hot water systems in South Australia',* 28 February 2023, accessed 28 June 2023. Available here. 4 AEMO, Forecasting Reference Group meeting 31 May 2023, available here. 5 Origin, Delivering the biggest infrastructure challenge in a century, 22 November 2022, accessed 28 June 2023, available here. 6 AEMO, Rule change request — Scheduled Lite Mechanism in the National Electricity Market, p 73 - Appendix B: High Level Design. 7 AEMO, Rule change request - Scheduled Lite Mechanism in the National Electricity Market, p 66. 8 AEMO, 2022 Integrated System Plan, p. 10, available here.

BOX 2: WHAT DOES INTEGRATING RESOURCES INTO SCHEDULING PROCESSES MEAN?

Every day scheduled generators give AEMO information on the amount of electricity they are willing to generate at different prices. The central dispatch process orders the generators' offers, from least to most expensive, and determines which generators will be dispatched to meet expected customer demand at the lowest cost. Scheduled generators must follow several requirements as part of this process.

Price-responsive resources as described above do not interact with the market in the same way.

The purpose of this rule change is to examine how price-responsive resources, that are not currently part of the central dispatch process, could participate to improve the efficiency of dispatch. These resources could provide information regarding their price sensitivity and ability to provide other market services that support system operation and security, which should reduce overall costs.

1.1 AEMO has proposed a new mechanism to integrate price-responsive resources into market scheduling processes

There is a growing quantity of price-responsive resources in the NEM. AEMO considers that over time these resources will play an increasingly important role in how the energy system performs. This is because the expected quantity of these resources and the energy service providers that will use these resources, will have the ability to change how energy is generated, stored and consumed. 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 states that its proposed mechanism will:[5]

- provide critical visibility and dispatchability services required to address complex and emerging power system challenges, avoiding the need for increasing reliance on intervention 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 has proposed changes to the NER to establish the new mechanism. These include:[6]

Establishing a 'Light Scheduling Unit' (LSU) classification so aggregated portfolios can be represented in market scheduling processes and systems. The classification would reference the two participation modes within an LSU (visibility and dispatch) and their purposes. Participants would classify as they currently do, for example as a Market Customer, a Generator or from 2024, an Integrated Resource Provider (IRP).

Creating a new "Light Scheduling Unit Guideline". Through this Guideline AEMO would develop most of the operational requirements for the mechanism. The Guideline would define:

- Visibility mode operational requirements
  - This would include requirements for data, telemetry and communications equipment, as well as compliance criteria and processes. It would also include requirements for the sharing of data with Distribution Network Service Providers (DNSP), as well as the requirements and processes a Market Participant would need to follow to opt in and out of the visibility mode.
- Dispatch mode operational requirements
  - This would include establishing the minimum threshold of a dispatch LSU and requirements for how they participate. It would also include requirements for

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

6 AEMO, Rule change request - Scheduled Lite Mechanism in the National Electricity Mechanism, pp. 26 - 33.

telemetry and communications equipment, compliance criteria and processes, as well as requirements and processes to follow when unavailable and returning to dispatch mode.

- Operating an LSU
  - This would include requirements for operation, such as the need to be the financially responsible market participant at that connection point. It would also include requirements and processes for entering inactive status including self-hibernation, enforced inactive status and requirements for reactivation.

Creating a new "Zonal Aggregation Guideline".[7] The mechanism recognises that economies of scale will drive value. AEMO proposes to use a Guideline to create this threshold amount and associated conditions. AEMO are currently proposing to set the threshold aggregation amount to participate in dispatch mode at 5MW.

Creating a new incentive payment arrangement for visibility mode.[8] AEMO believes that participants will need to receive an incentive to participate in visibility mode. This new payment for visibility services could be designed in a number of ways. For example, payment to all participants or through a tender process for specific regions and time periods. AEMO has not proposed a preferred mechanism for this.

Including dispatch mode in central dispatch. AEMO has identified a range of changes that would need to occur to enable price-responsive resources in dispatch mode to participate in central dispatch. These include:

- extending the arrangements for how bi-directional units (BDUs) are dispatched and scheduled to dispatch LSUs[9]
- allowing dispatch LSUs to access frequency performance payments[10]
- including dispatch LSUs as 'scheduled resources' in system security obligations[11]
- confirming that data may be appropriately shared with network service providers, and
- other additional amendments to ensure the operation of other functions.

AEMO identified a number of subsequent procedure changes that would also be required, including:[12]

- most registration and classification documents to accommodate classification of LSUs,
- the Guide to Generator Exemption and Classification of Generating units, and
- the System Operation Procedures (including Dispatch Procedure, Pre-Dispatch procedure, Spot Market Operations, Timetable procedure, Load Forecasting procedure and Short-Term projected assessment of system adequacy (ST PASA) process description).

7 AEMO, Rule change request - Scheduled Lite Mechanism, p 27-29.
8 AEMO, Rule change request -Scheduled Lite Mechanism in the National Electricity Market, p 30-31
9 Clauses 3.8.2(a), 3.8.3A, 3.8.19, 3.8.6, 3.8.22 and 3.8.22A of the NER.
10 Clause 3.15.6AA of the NER.
11 Clauses 4.8.9, 4.9.2, 4.9.4 and 4.11.1 of the NER.
12 AEMO, Rule change request - Scheduled Lite Mechanism in the National Electricity Market, p 33.

1.2 This request interacts with other NEM reforms

This rule change proposal forms part of the Energy Security Board's (ESB's) Horizon One CER Implementation Plan. An overview of the ESB's work can be found on its website.[13]

Several reforms are relevant for, or intersect with this rule change request, including:

- **Unlocking CER benefits through flexible trading** — AEMO proposed a rule change to enable consumers to have their CER separately metered and therefore treated independently in market settlements. Separating passive load (for example lights, fridges, TVs) from price-responsive resources (for example EVs and controllable hot water heaters) at the connection point may enable better participation in this Scheduled Lite mechanism. The AEMC is considering this rule change request, with a Directions Paper released today.[14]
- **Project EDGE** — Project EDGE (Energy Demand & Generation Exchange) is a collaboration between AEMO, AusNet Services, Mondo and ARENA. This trial aims to show how consumer participation in a DER marketplace could be facilitated, enabling the trade of services in the wholesale market, and local market services with the DNSP.[15] This trial tested and informed elements of AEMO's proposed design of the Scheduled Lite mechanism. In addition, this project is doing a comprehensive cost-benefit analysis of whether the implementation of an operational DER marketplace is in the long-term interests of consumers.[16]
- **Dynamic Operating Envelopes (DOEs) and Flexible Export Limits (FELs)** — Most DNSPs currently rely on static operating envelopes (with trials of other approaches occurring) to limit import from and export to the electricity grid. DOEs and FELs are emerging network capacity management tools that can allow distributors to dynamically vary the network connection export (and import) limits of consumers.

  The AER is currently undertaking a review of the current regulatory framework to evaluate the appropriateness of DNSPs implementing FELs.[17]

  Allowing these limits to vary over time and location through 'dynamic' operating envelopes could help manage network constraints. The application of DOEs and FELs are important considerations for participants who would need to also comply with these as part of any scheduling process.
- **AEMC's review of the regulatory framework for metering services** — this review is seeking to identify reforms to accelerate smart meter deployment in the NEM. Smart meters are required to enable many of the other reforms to occur.[18]

13 Available here. https://esb-post2025-market-design.aemc.gov.au/

14 AEMC, *Unlocking CER benefits through flexible trading*. https://www.aemc.gov.au/rule-changes/unlocking-CER-benefits-through-flexible-trading

15 AEMO, Project EDGE, accessed 28 June. https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge

16 AEMO, Project EDGE cost-benefit analysis. https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge/project-edge-reports/cost-benefit-analysis

17 AER, *Review of regulatory framework for flexible export limit implementation,* October 2022.

18 AEMC, Review of the regulatory framework for metering services project page. Available at: https://www.aemc.gov.au/market-reviews-advice/review-regulatory-framework-metering-services

- **AEMC's review into CER technical standards** — the review aims to improve compliance with the technical standards for CER devices. Improving compliance will benefit all electricity consumers in the NEM. This is because more CER devices will behave as expected, supporting DNSPs and AEMO in operating the electricity system and planning for its future needs. In addition, improved compliance will result in CER device owning consumers gaining greater benefits from their devices as well as enabling more consumers to connect new CER devices. This supports the security and reliability of power supply. It is also an important avenue for the energy sector to reduce emissions and contribute towards government commitments for Australia to achieve net zero.[19]
- **ESB's policy advice for the application of technical standards - EV charging standards** — the EV charging standards policy advice will assist the development of regulatory and market settings to support smart EV charging in the NEM.[20]
- **Project Edith** - Project Edith is demonstrating how to manage network operations by applying dynamic network pricing to aggregators with support from dynamic operating envelopes at times of more severe constraints. Through this trial the aggregator is optimising across market contingency FCAS, non-market RERT and network price signals.[21]
- **The AER review of consumer protections for future energy services** — As part of the AER's review, it is considering if energy-specific consumer protections are needed for services that do not currently fall within the National Energy Consumer Framework (NECF).[22]

AEMO identified and summarised a number of other relevant trials and reforms in Appendix B to the rule change request (including Integrating energy storage systems, semi-scheduled self-forecasting, Project Symphony, SCADA Lite and VPP demonstrations).[23]

1.3 We have started the rule change process

This paper is the first stage in our formal consultation process.

A standard rule change request has several stages, including a rule change request, a consultation paper, a draft determination, a draft rule change for consultation, a final determination and a final rule. Given the complexity of this rule change request, we may consider a longer timeframe to fully examine and work through solutions. This process may include an additional step of an options or directions paper before the draft determination, or a technical working group to assist in designing the solution. This will depend on the submissions received to this consultation paper.

19 AEMC, Review into consumer energy resources technical standards project page. Available at: https://www.aemc.gov.au/market-reviews-advice/review-consumer-energy-resources-technical-standards

20 ESB, Electric Vehicle Smart Charging Issues Paper, June 2022. Available a: https://esb-post2025-market-design.aemc.gov.au/integration-of-distributed-energy-resources-der-and-flexible-demand#electric-vehicle-smart-charging-issues-paper

21 Ausgrid, Project Edith. Available at: https://www.ausgrid.com.au/About-Us/Future-Grid/Project-Edith

22 AER, *Review of consumer protections for future energy services, options for reform of the National Energy Customer Framework*, October 2022.

23 AEMO, Rule change request - Scheduled Lite Mechanism in the National Electricity Market, Appendix B.1.

Indicative time frames for the proposed process are contained in the following table.

Table 1.1: Rule change — indicative timelines

STAGE	TIME FRAMES
AEMO submitted rule change request	10 January 2023
Commission publishes consultation paper	3 August 2023
Stakeholder submissions due	14 September 2023
Commission publishes draft determination and draft rule	December 2023
Stakeholder submissions due	February 2024
Commission publishes final determination and final rule	May 2024

We seek stakeholder feedback on the problem of price-responsive resources not being able to engage with the wholesale market, the impact this will have, how we propose to assess the request, and the proposed solutions. Information on how to provide your submission and other opportunities for engagement is set out in the Summary.

You can find more information on the rule change process in *The Rule change process — a guide for stakeholders.*[24]

After we publish the final determination and rule (if made), there will be an implementation period which may include preparation activities by other bodies such as AEMO or the AER, prior to the rules taking effect.

24 The rule change process: a guide for stakeholders, June 2017, available here: https://www.aemc.gov.au/sites/default/files/2018-09/A-guide-to-the-rule-change-process-200617.PDF

2 WHAT IS THE PROBLEM CAUSED BY PRICE-RESPONSIVE RESOURCES NOT BEING FULLY INTEGRATED INTO THE ELECTRICITY MARKET?

AEMO considers that price-responsive resources will detrimentally affect market operation if they are not visible in market processes. AEMO states that operationally, the variable nature of these resources, coupled with the lack of their visibility and integration into market scheduling processes, is already challenging the secure and reliable management of the power system.

This chapter seeks stakeholder feedback on AEMO's problem definition. We are also seeking stakeholder views on how we have broken down the problem into different issues across a variety of timeframes.

2.1 How are price-responsive resources participating in electricity markets now?

2.1.1 Price-responsive resources are used to provide some services but aren't scheduled in the wholesale market

Price-responsive resources are currently providing services such as:

- Contingency frequency control ancillary services (FCAS), which are procured by AEMO as market ancillary services through the NEM dispatch engine (NEMDE). Provided that a participant, including aggregated households participating as VPPs, meets the technical requirements defined in AEMO's Market Ancillary Services Specification (MASS), they can participate in the contingency FCAS markets.
- Network support for DNSPs, such as generating at peak times to avoid the need for network expenditure. The demand management incentive scheme (DMIS) encourages distribution businesses to find lower-cost solutions instead of investing in network solutions.[25] This scheme works by providing distribution businesses with financial incentives to spend efficiently on non-network solutions to manage peak electricity demand.[26]
- RERT, which are out-of-market services procured by AEMO when available electricity supply in the market cannot meet forecast demand. For example, an aluminium smelter, which is not participating in the wholesale or FCAS market may be willing to pause operations to reduce its demand during specific periods of high demand or low supply.
- Network support and control ancillary services (NSCAS), which are non-market ancillary services that may be procured by AEMO or Transmission Network Service Providers (TNSPs). These services maintain power system security and reliability and maintain or increase the power transfer capability of the transmission network.

25 Clause 6.6.3 of the NER.

26 Each DNSP in their DAPR must report on their demand management activities including any non-network options that have been considered.

2.1.2 Mostly these resources are not visible to the market or market operator

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.[27] In 2021, the Commission decided that batteries above 5MW would be required to be scheduled for their load and generation.[28] 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 groups of smaller resources controlled by the same market participant could in aggregate be over the generator threshold, they do not have to meet the same requirements. There is no requirement for them to participate in the wholesale energy market. The current mechanisms and the potential to amend these are discussed in Chapter 4.

Retailers purchase electricity on their customers' behalf in the spot market. Given this exposure to wholesale market prices, retailers can coordinate price-responsive resources to reduce the costs they incur without being scheduled in the wholesale market.[29] They can do this in several ways, including by:

- adjusting the volume of energy purchased, through either a reduction in load or an increase in generation of resources that they control,
- shifting flexible load across the day into lower price periods to reduce total wholesale market costs, ie, wholesale market price arbitrage, and
- lowering hedging costs, as demand flexibility substitutes for contracts providing protection from high prices.

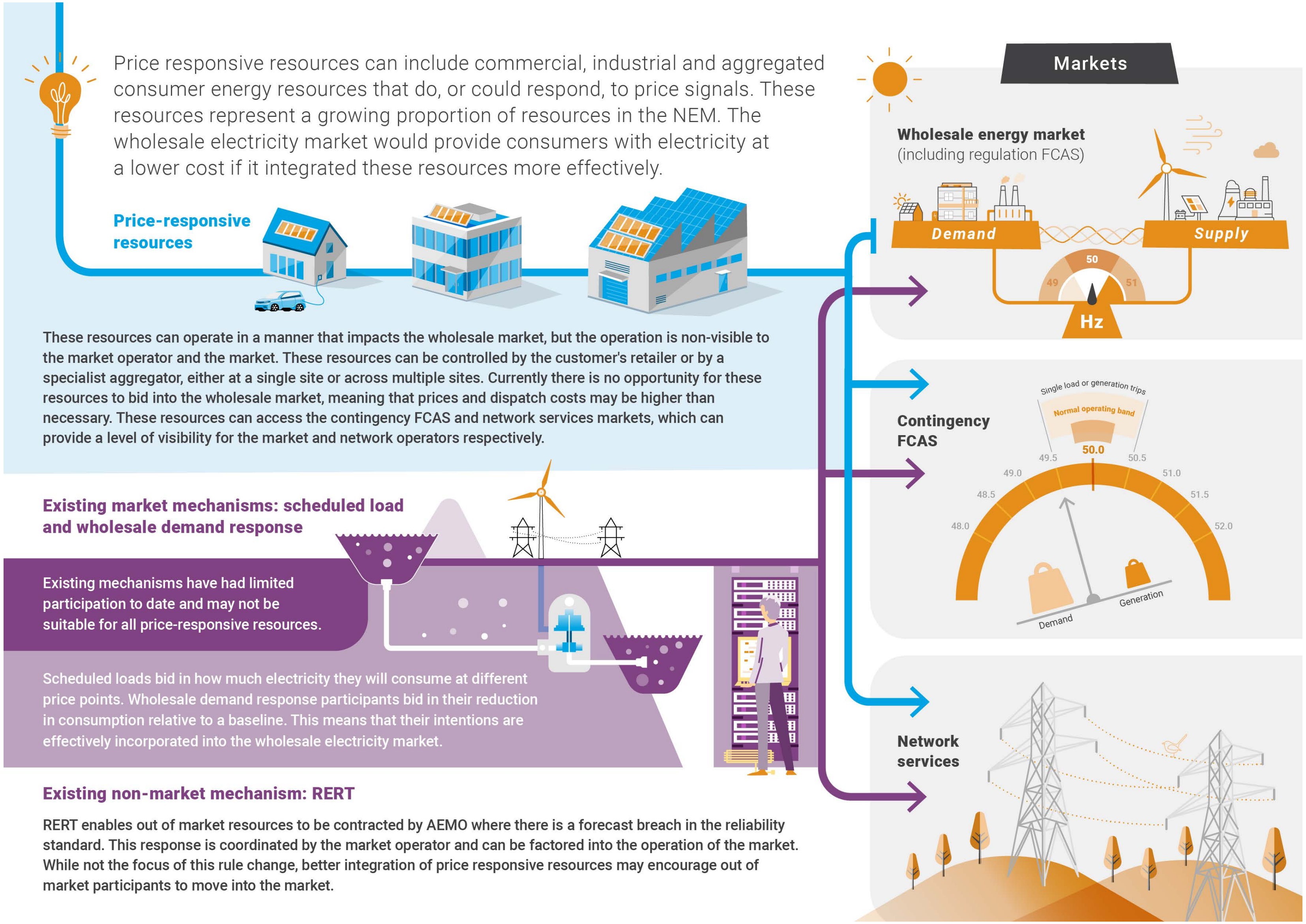
Where a retailer coordinates price-responsive resources to reduce wholesale electricity purchase costs, lower its hedging costs or get paid the market price for their non-scheduled output, there is an asymmetry in information between the retailer and both the market operator and other market participants.

27 AEMO, *Guide to generator exemptions and classification of generating units*, [2022] https://aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/New-Participants/Generator-Exemption-and-Classification-Guide.docx.

28 AEMC, Integrating Storage into the NEM, 2 December 2021, p 20. Available at: https://www.aemc.gov.au/sites/default/files/2021-12/1._final_determination_-_integrating_energy_storage_systems_into_the_nem.pdf

29 This differs from parties that are not the retailer for the site and therefore not exposed to wholesale prices and aggregate resources to access other markets such as FCAS.

Figure 2.1: Price-responsive resources in the NEM

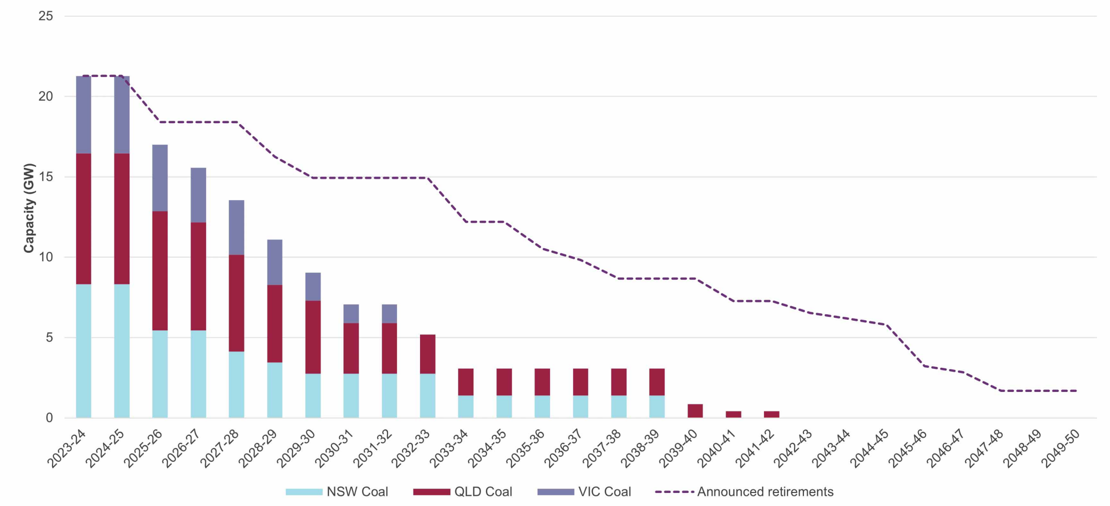


Source: AEMC

2.2 AEMO considers integrating price-responsive resources in the NEM will be critical in the future

AEMO's Integrated System Plan (ISP) sets out an optimal development path to transition the energy market to achieve net zero by 2050.[30] Two key transitions considered in this plan are the retirement of coal-fired generation in the next 20 years (see figure 2.2) and the expected growth of distributed PV and storage (see figure 2.3). These two changes will have a significant impact on the operation of the energy market.

Figure 2.2: Forecast coal retirements



Source: AEMO, Rule change request - Scehduled Lite mechanism in the National Electricity Market, p. 53.

AEMO expects that in order to operate the grid with large amounts of variable renewable energy (VRE), generation that can help to keep the grid stable will be needed. This firming capacity is expected to be comprised of 46GW / 640 gigawatt hours (GWh) of dispatchable storage, in all its forms, by 2050. Price-responsive resources, in particular VPPs, Vehicle to Grid (V2G) services and other emerging technologies, are expected to provide approximately two-thirds of this, or around 31 GW, of dispatchable storage capacity (see figure 2.3).[31]

The ISP shows that the required additional investment in large-scale firming capacity will depend on the extent to which these price-responsive resources can be used to fulfil power system needs.[32] AEMO states that duplicating 20 per cent of the projected coordinated price-responsive resources through investment in additional shallow grid-scale storage (2-hour large-scale batteries) each year to 2040 would come at a cumulative capital cost of around

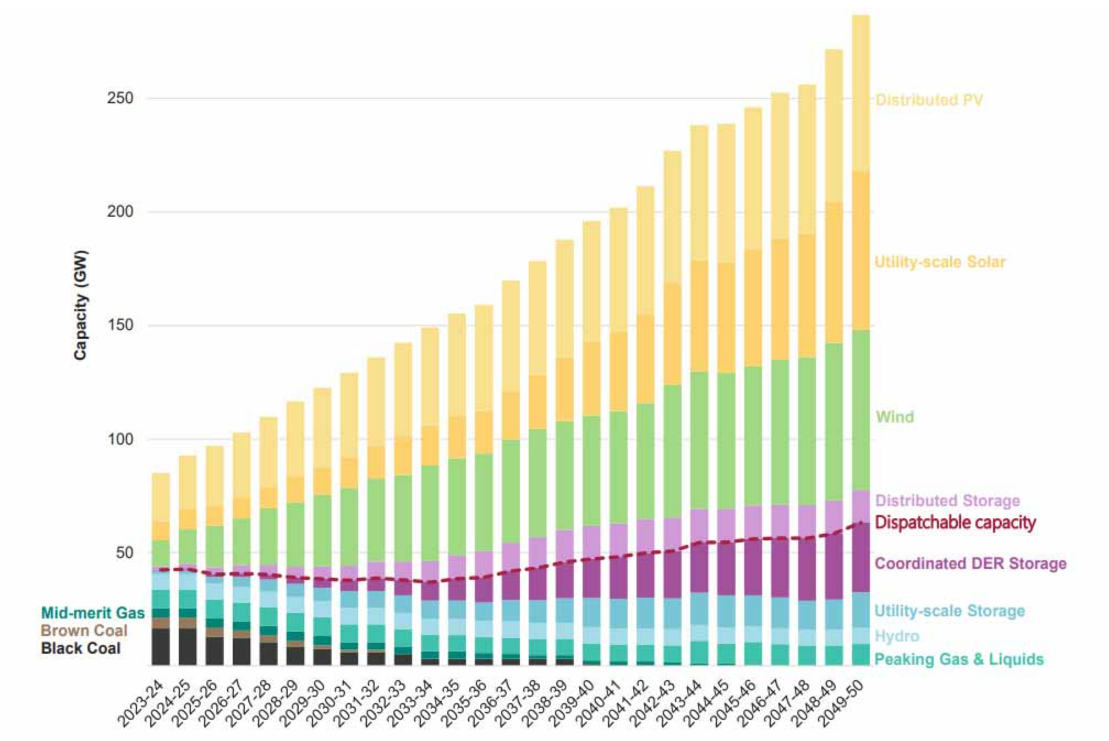
30 AEMO, 2022 Integrated System Plan, p. 3. Available here.

31 AEMO, 2022 Integrated System Plan, p 12. AEMO, Rule change request - Scheduled lite mechanism in the national electricity market, p 10.

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

$1.8 billion, rising to approximately $4.4 billion if 50 per cent of the capacity were to be replicated over that same period.[33]

Figure 2.3: Forecast NEM capacity by resource type to 2051



Source: AEMO, 2022 ISP Results Step Change Scenario, June 2022, p. 9. Available here

2.3 Types of impacts that price-responsive resources will cause

This section sets out the Commission's consideration of potential issues with price-responsive resources not being integrated into the market services in the NEM. In particular, it explores and seeks stakeholder views on the impact of the significant expected increase of non-visible price-responsive resources on the efficiency of:

- dispatch costs in the NEM,
- energy prices in the NEM,
- reliability of supply in the NEM,
- security of supply in the NEM, and
- operation of distribution and transmission networks.

Table 2.1 summarises the types of inefficiency caused by price-responsive resources not being integrated into the NEM. These are expanded on below.

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

Table 2.1: Categories of inefficiency caused by price-responsive resources not being integrated in market systems

TIME FRAME	DISPATCH COSTS	PRICE	SECURITY	RELIABILITY	NETWORKS
Pre-dispatch and dispatch time frames	Inaccurate demand forecasts Inefficient dispatch Poor generator targets	Inaccurate spot price Consumers pay too much for energy Increase in FCAS prices when demand requirements are inefficiently high	Increased need for regulation FCAS and Contingency FCAS Generator unloading or under-frequency load shedding Major system security challenges	Inaccurate reserve capacity assessments More frequent Low reserve condition (LRC) or lack of reserve (LOR) conditions and use of RERT	Operational issues Curtailment, backstop measures and load shedding Conservative constraints
0-7 days (ST PASA)	Inefficient operation of generators	Inaccurate spot price forecasts	NA	More frequent LRC or LOR conditions and use of RERT	Inefficient outage planning Ineffective NSCAS and network support arrangements
7 days – 36 months (MT PASA and network outage schedule)	NA	Inefficient investments in generation, storage and demand response	NA	Long notice RERT potentially triggered	More conservative limits on dispatch Conservative DOEs
Long term (ESOO, ISP)	NA	Inefficient investments in generation, storage and demand response	NA	Retailer reliability obligation (RRO) t- and t-3 potentially triggered Inefficient investment	Inefficient investments RIT-D/T outcomes unreliable

Source: AEMC

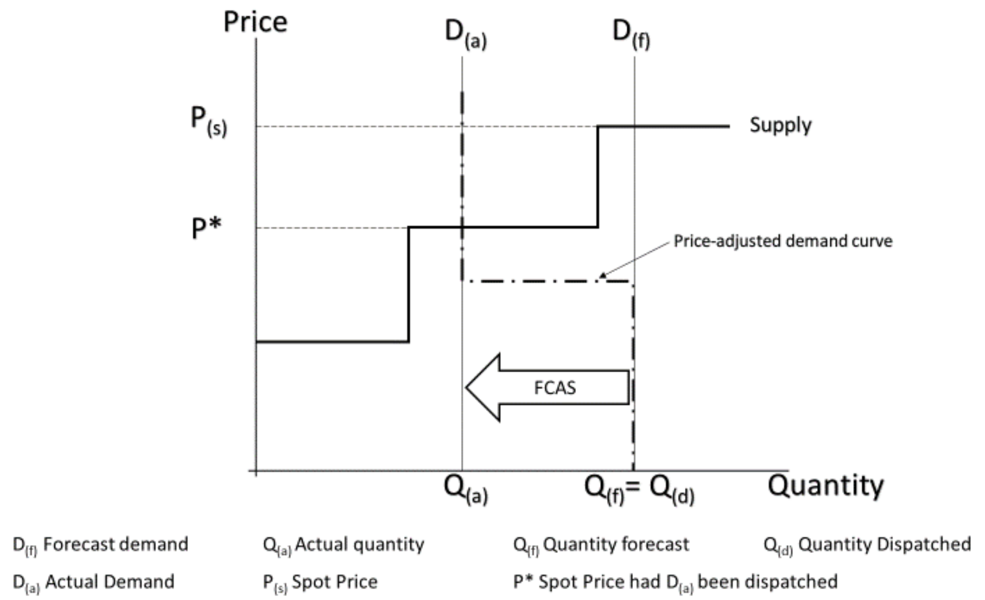
2.3.1 Dispatch will become inaccurate

Accurate demand forecasts in dispatch, pre-dispatch and ST PASA timeframes are important to facilitate the lowest cost dispatch to meet demand. As the volume of unscheduled price-responsive resources increases, demand forecasting will become more challenging for AEMO.

Inaccurate demand forecasts in dispatch time frames will result in the determination of incorrect dispatch targets for scheduled and semi-scheduled plant. For example, overestimates of demand result in the dispatch of high-cost plant which is not necessary to meet actual demand. The deviations from demand forecasts then also have to be made up for through FCAS to balance supply and demand.

Figure 2.4 provides a stylised example of the outcomes in dispatch costs, prices and security, when price-responsive resources are not included in the market demand forecast. As AEMO does not know the intentions of these resources, it may forecast higher demand, D(f), and use generator bids to achieve this level of supply in the most efficient way. This results in a price point of P(s), as all generators are paid for the energy provided when dispatched. However, as there are several resources that will not consume at this price point, the actual demand is lower than forecast, D(a). To balance supply with the actual demand level FCAS has to be procured. This shows that not only is the price higher than it should have been, additional costs were incurred to meet the over forecast of demand, and then further costs are incurred to bring supply and demand back into balance through FCAS.

Figure 2.4: Inaccurate demand forecast leading to higher prices and need for FCAS to balance energy



Source: AEMC

In a self-commitment market such as the NEM, inaccuracies in ST PASA time-frames also have the ability to cause inefficiently high dispatch costs. This is because generators have to make fuel and unit commitment decisions before dispatch and these are influenced by demand forecasts. For example, if in the future one retailer operated a large VPP and were not required to bid in that VPP in pre-dispatch, this would likely lead to significant challenges for all other participants in making decisions in ST PASA timeframes.

2.3.2 Prices will likely be inefficient

Where dispatch demand forecasts are materially inaccurate, it is likely that prices will not be set at efficient levels. In particular, where the demand forecast does not take into account material amounts of resources that would respond to high prices, demand is likely to be overestimated and prices set above efficient levels.

Inefficiently high prices are likely to have a direct effect on consumers.[34] They are also likely to cause inefficiency across various time horizons:

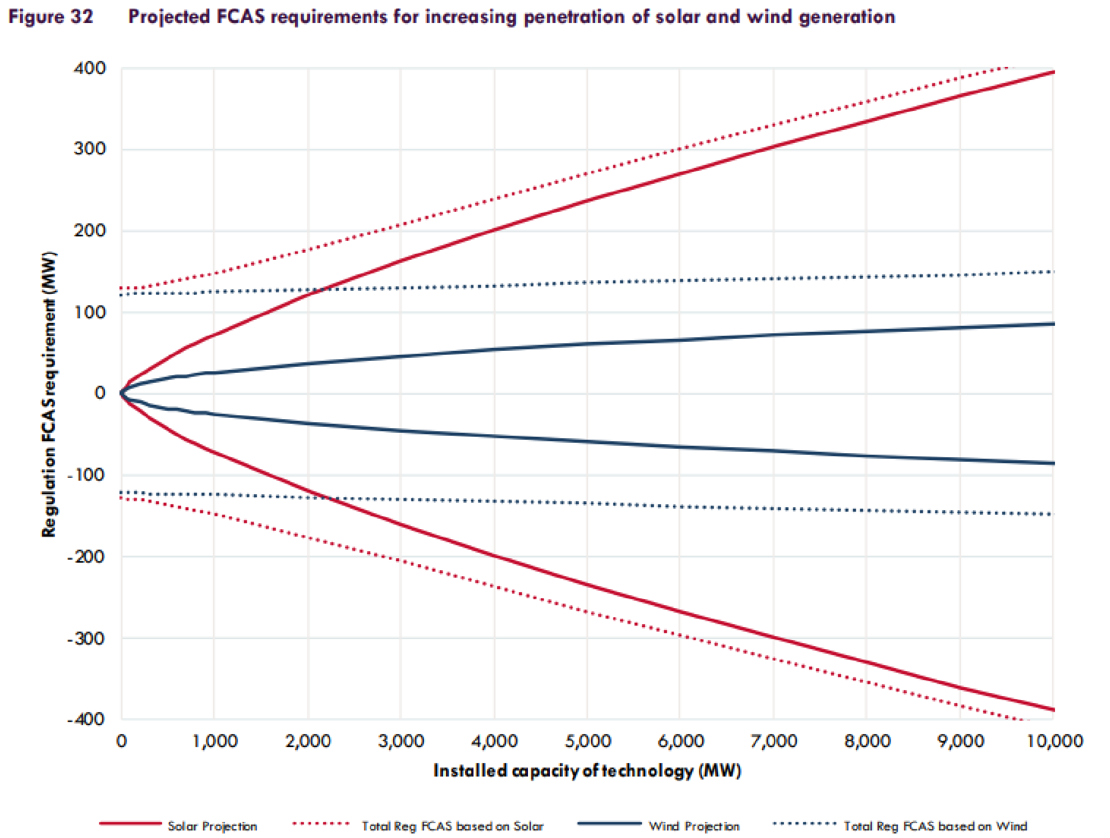
- they are likely to cause an unnecessary response from other resources in dispatch time-frames, for example, demand response.
- scheduled and semi-scheduled generator energy revenue will become more uncertain as their volumes differ from targets.
- larger volumes of FCAS will have to be provided at higher costs.
- a significant portion of electricity contracts also settle against spot market prices. Higher spot market prices are likely to increase overall hedging costs.
- if persistent, over time, they are likely to drive investment in generation and demand response as participants respond to price signals.

2.3.3 Meeting system security requirements is likely to be more expensive

Even without better integrating these resources, there will be a greater need for FCAS as resources in the NEM are increasingly being made up of VRE (see Figure 2.5). This is because regulation FCAS is used to correct errors in the supply-demand balance.

34 One-off high spot prices directly affect market-exposed consumers - if there are repeated high spot prices that increase the average dispatch prices, then that flows through to (non-market exposed) consumer pricing outcomes

Figure 2.5: Increasing FCAS requirements with increasing penetration of solar and wind generation



Source: AEMO, 2018 Integrated System Plan, p. 68 Figure 32, July 2018. Available here

The impact on the system will be exacerbated as the combined size of the non-integrated price-responsive resources increases. This may also occur if their response is instantaneous or non-linear over a dispatch interval. Even on a small scale, unpredictable action by price-responsive resources can have a material effect in aggregate. This aggregate effect can lead to increased requirements for the use and enablement of regulation services resulting in increased costs that are ultimately borne by consumers.

In a more severe case, aggregate deviations from forecast demand have the potential to shift the system frequency outside the bounds of the normal operating frequency band and trigger contingency FCAS. It is foreseeable that these resources could affect the system frequency sufficiently to require contingency FCAS. Contingency FCAS is required to rapidly correct the system frequency and is conventionally provided by generators enabled in the contingency FCAS dispatch process. However, where the change is sufficiently large or rapid, automatic contingency FCAS facilities could operate, including:

- automatic under-frequency load shedding of customers could occur if there was a significant increase in demand in response to a low price

- automatic over-frequency generator unloading could occur in response to a significant drop in demand in response to a high price.

Maintaining power system security is vital. Uncertainty regarding the operation of these resources and the potential mismatch between supply and demand that can occur when they operate without warning is likely to also drive conservatism in the operation of the interconnectors. This could be done by AEMO, in conjunction with TNSPs. They may reduce the normal operating range of interconnectors to accommodate unpredictable changes that may exceed safe operational limits.

If AEMO is using FCAS resources to respond to changes caused by non-visible price-responsive resources, then it may not have the resources to deal with other events. This could result in more security issues for the system or more resources needing to be procured at a higher cost to consumers.

2.3.4 Additional resources may need to be obtained to ensure reliability

AEMO has a variety of forecasts that inform the market of expected conditions in different time periods. If price-responsive resources are not integrated then there are consequences for the efficiency of these processes.

In the short term;

- demand forecasts inform the assessment of LOR notice conditions during the ST PASA, pre-dispatch and dispatch processes. Different LOR conditions signify different levels of potential shortfalls in available capacity to meet forecast demand.
- price-responsive resources in these circumstances have the potential to reduce or remove LOR conditions. This would avoid the use of expensive out-of-market measures such as RERT or directions for which a participant may seek compensation. While they remain non-visible, the LOR conditions would persist. This could result in unnecessary procurement and use of RERT.

In the medium term;

- planning tools such as MT PASA are used by AEMO to predict shortfalls in available capacity and schedule generator planned outages. Inaccurate demand forecasts could result in inappropriate messaging of the reserve situation.
- the RRO is triggered by the reliability projections in the Electricity Statement of Opportunities (ESOO). Excluding the price-responsive resources would effectively reduce the level of capacity available to meet peak demand, potentially triggering the RRO more frequently.

State and Federal Governments are keenly interested in ensuring the ongoing reliability of energy supply and have initiated a number of investment programs. If these price-responsive resources remain non-visible, AEMO will likely increasingly report reliability issues due to a lack of known firm capacity, resulting in more expansive programs and investments. These would potentially be inefficient as they duplicate existing consumer resources.

Over longer time frames, such as those covered by the ISP and ESOO, AEMO assumes that price-responsive resources will actively participate in the market.

2.3.5 Networks may become less efficient

Non-visible price-responsive resources also affect network operation, maintenance, planning and development. If price-responsive resources are not integrated then networks may become less efficient.

Maximising network use depends on being able to describe the possible operating conditions under which they will operate. Normal operating limits for the network reflect the ability of the network to accommodate expected loads and flows. These are determined in sophisticated simulation processes that examine credible and foreseeable variations and plant failures. Demand variations are a key element considered in these simulations. If the magnitude of the potential demand variations increases, the normal operating limits of network elements are likely to decrease accordingly. This could impact services offered and used by customers through more conservative operating limits, including potentially curtailing the export of services during times of uncertainty.

AEMO assists in making transmission network operation and outage scheduling decisions. These decisions are based on outage information provided by the network service providers, generator availability information from market participants and load forecasts. However, at the distribution network level, AEMO does not have a role and often does not have visibility of outages. DNSPs also do not have visibility of price-responsive resources. While the volume and behaviour of price-responsive resources remain non-visible, AEMO will be forced to take a conservative approach with its advice on the timing of transmission network outages. Network operators can, at times, avoid or delay costly network upgrades by negotiating network support arrangements with local consumers or generators. The efficacy of these agreements could be compromised if the forecasts of demand are unreliable, potentially bringing forward costly network investment. The lack of broad visibility by the market and AEMO means that conservative assumptions are used.

These price-responsive resources could impact the outcome of network investments through the regulatory investment tests (RITs). The RITs test the economic efficiency of different investment options for the networks to address different needs, including in response to changing consumer energy usage patterns. Low integration of price-responsive resources could increase peak network demands, resulting in increased investment expenditure.[35]

QUESTION 1: DO YOU AGREE THAT PRICE-RESPONSIVE RESOURCES NEED TO BE INTEGRATED INTO THE NEM?

1. The Commission has identified five types of issues with increasing volumes of price-responsive resources. Do you agree with this breakdown of the issues? What do you consider the magnitude of each issue is? How is this likely to change over time?

35 AER, *RIT-T and RIT-D application guidelines*, 2022.

3 AEMO'S PROPOSED SOLUTION

This chapter seeks feedback on AEMO's proposed solution 'Scheduled Lite Mechanism', which comprises two modes: visibility and dispatch.

- **Visibility mode**: this mode is designed to integrate the intentions of price-responsive resources to improve the accuracy of short-term demand and price forecasting. Participants will provide a forecast of generation and consumption called "indicative bids".
- **Dispatch mode**: this mode is designed to integrate price-responsive resources into the NEM central dispatch and scheduling processes. Participants will be able to provide bids for their generation and load, receive and follow dispatch targets.

AEMO proposed an evolving mechanism as the size and capabilities of price-responsive resources increase.[36] Visibility mode is considered as an entry mode, with an expectation that traders (defined below) would move to dispatch once they are comfortable being able to comply with targets. However, there is no required threshold (for example time or size) envisaged where a trader would need to move from visibility to dispatch mode.

Under AEMO's proposal, the mechanism is voluntary, with participation encouraged through the use of incentives. A payment is proposed to traders who participate in visibility mode. Encouragement to participate in dispatch mode is through access to wholesale electricity and other markets.

It is important to note that residential and small customers would not directly participate; this mechanism is designed for traders that operate resources on customers' behalf.[37] Throughout this section, the term "trader" will be used as a general term to describe energy service providers participating in scheduled lite (for example, retailers and aggregators).[38]

In this section, we focus on how price-responsive resources could be incorporated into AEMO's systems, the incentives for participating and whether the two proposed modes would achieve the objectives identified in section 2.3.

3.1 Representing price-responsive resources in AEMO's systems

3.1.1 A new classification

In order to integrate price-responsive resources, as defined in Box 1 and Box 2, into AEMO's systems, AEMO proposes introducing a new classification for resources involved in Scheduled lite, called an LSU.[39] AEMO proposes that traders would classify their resources within an LSU.[40] Each LSU would be assigned a Dispatchable Unit Identifier (DUID) for bidding, scheduling and dispatch purposes. National Meter Identifiers (NMIs) would be aggregated on a zonal basis.

36 AEMO, Rule change request - Scheduled Lite Mechanism in the National Electricity Market, p 20.

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

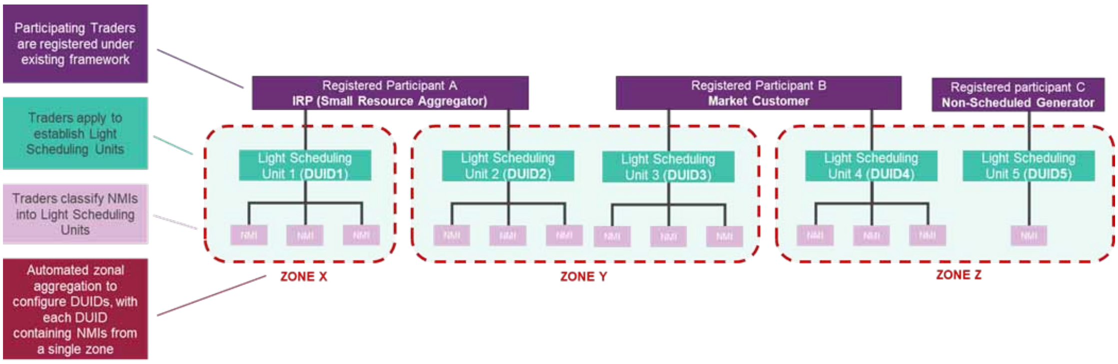
38 For this paper, "trader" does not have the meaning it has in the NER.

39 Market participants seek classification of their resources in accordance with chapter 2 of the NER. Current classifications include generating units, small generating units, market loads, ancillary service loads and wholesale demand response units.

40 AEMO, Rule change request - Scheduled Lite mechanism in the National Electricity Market, p. 90

LSUs would be used to participate in both visibility and dispatch modes.[41] Figure 3.1 provides an example of how the different resources and traders would classify their portfolios.

Figure 3.1: Proposed classification and aggregation framework



Source: AEMO, Rule change request - Scheduled Lite mechanism in the National Electricity Market, p. 90

3.1.2 Scope of price-responsive resources

The type of resources that can be classified within an LSU is an important consideration as it may include aggregated small resources, or larger loads and generators that are not currently scheduled. While we have outlined the potential scope of these resources in Box 1, there currently is no definition that would easily capture or identify these price-responsive resources. AEMO's mechanism avoids having to deal with this as they propose a voluntary mechanism for traders to opt-in. Alternative arrangements, or mandatory arrangements, would likely need to create a definition of price-responsive resources.

3.1.3 How different price-responsive resources would participate

The *Unlocking CER benefits through flexible trading* rule change is considering the separation of price-responsive resources from other resources behind each consumer's connection point. If progressed this would allow price-responsive resources to be treated independently of non-price-responsive resources in wholesale settlement.[42]

Based on Project EDGE trial findings, there may be value from separate recognition of flexible resources in the market. The Project EDGE trial indicated that participation in "Flex" mode, whereby the trader is bidding and being dispatched only for price-responsive resources under their control, rather than the full load of customers, led to lower conformance errors. This is because removing the uncontrolled load enabled better management of dispatch non-conformance risks as the aggregator did not need to account for the behaviour of uncontrolled load in its bidding and dispatch processes.[43]

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

42 AEMC, *Unlocking CER benefits through flexible trading* consultation paper, 8 December 2022.

43 AEMO, Project EDGE, accessed 28 June 2023. https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge

Larger non-scheduled loads and generators may have different considerations in terms of how they participate. If they are only managing one site, participation and compliance may be easier than if they are aggregating a large number of small loads/ generators. AEMO note in their request that these loads may instead participate as stand-alone LSUs rather than being aggregated with other resources.[44]

We note that this mechanism may be an alternative arrangement to ones that these resources are already participating in, particularly RERT. RERT allows AEMO to contract for reserves (generation or demand-side capacity that is not otherwise available to the market through any other arrangement).[45] Participating in this (or a similar mechanism) would exclude these resources and participants from RERT.

QUESTION 2: REPRESENTING PRICE-RESPONSIVE RESOURCES IN SCHEDULING PROCESSES

1. Is participation in this mechanism dependent on whether price-responsive resources can be separated at or behind the connection point (currently being considered through the "Unlocking CER benefits through flexible trading" rule change)? Please explain what impacts separating CER would have on traders' participation in energy markets.
2. Do you have views on the need to define price-responsive resources or the traders that might coordinate a large amount of such resources?

3.2 Visibility mode

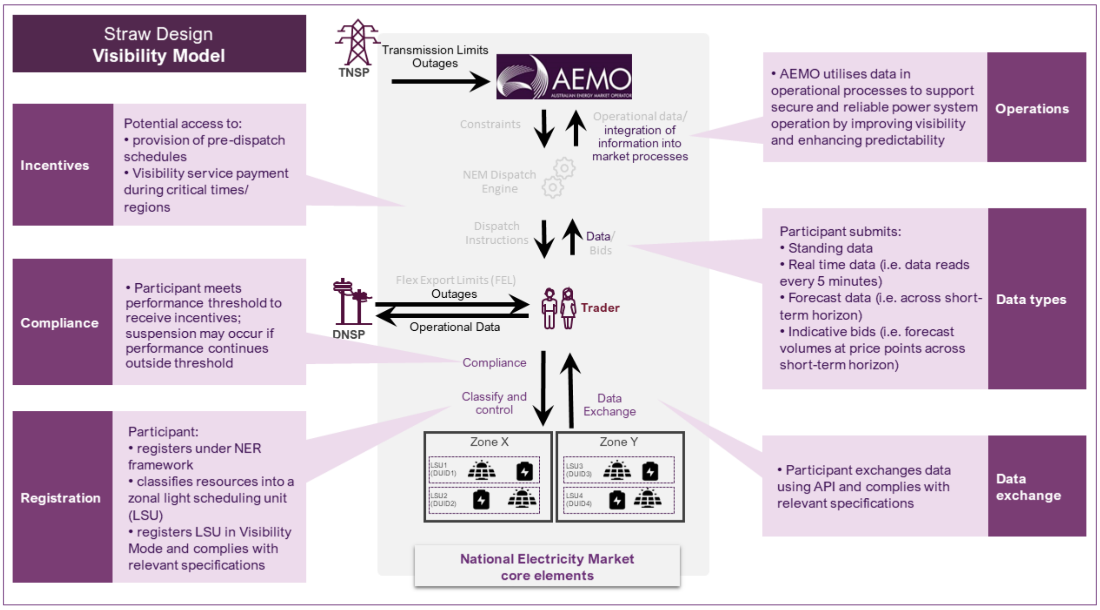
AEMO proposes that the visibility mode would enhance load and price forecasting by enabling traders to provide AEMO with information regarding the behaviour of price-responsive resources. More broadly, greater information would allow market participants to make more informed generation, storage or consumption decisions.

Information that AEMO gathers from visibility mode would inform pre-dispatch, ST PASA and other operational activities. AEMO considers that this would improve scheduling processes, leading to less conservative operation of the system. For example, less RERT and FCAS may be needed as AEMO would be aware of any potential response. Further description of how the problem arises is set out in section 2.3. Figure 3.2 provides a high-level overview of how the model could work.

44 AEMO, Rule change request - Scheduled Lite Mechanism in the National Electricity Market, p. 91

45 Clause 3.20.3(h) of the NER.

Figure 3.2: AEMO straw design of Visibility mode



Source: AEMO, Fule change request - Scheduled Lite mechanism in the National Electricity Market, p. 75.

3.2.1 What are the incentives to participate?

AEMO considers that the benefits of participation are to the market and AEMO, rather than to the participants themselves. Therefore, AEMO proposed that participants would need to receive an incentive to opt into this mode. AEMO proposed four incentive options:[46]

1. pre-dispatch schedule provided to participants — this would outline the trader's forecast consumption and generation based on their indicative bid information and would be published privately to the trader[47],
2. reduced cost recovery for participants for:
    a. market ancillary services
    b. NSCAS and system restart
    c. interventions
3. payment — AEMO has identified that this could be made up in a number of ways, such as to all participants or through a tender process in specific regions and time periods. This payment would be levied from other market participants[48], or
4. link eligibility to provide contingency FCAS to participation in Scheduled Lite.

46 AEMO, Rule change request - Scheduled Lite Mechanism in the National Electricity Market, p 112.
47 AEMO, Rule change request - Scheduled Lite mechanism in the National Electricity Market, p. 113
48 AEMO, Rule change request - Scheduled Lite mechanism in the National Electricity Market, p. 113

To facilitate stakeholder submissions Table 3.1 presents a high-level summary of our initial analysis of the relative merits of the proposed incentives. We have also added an additional option for required participation. While incentive-based processes may be preferable, such arrangements also need to be effective. Therefore, in recognition of the importance of price-responsive resources in delivering future reliability, security, emissions reduction and efficient pricing, we are also seeking stakeholder feedback on the criteria or circumstances that may justify required participation, and who that could apply to.

Table 3.1: **Relative merits of proposed options for participation incentives**

INCENTIVE MECHANISM	ADVANTAGES	DISADVANTAGES
1. Pre-dispatch schedule provided to participants	Supports informed decision-making by participants in relation to the operation of price-responsive resources	Following the pre-dispatch schedule may be less flexible than remaining in non-market arrangements. Traders could participate with a small amount of price-responsive resources to gain access to this information, but leave the majority of their resources operating out of the market. This could be addressed in the solution design. May not incentivise participation of price-responsive resources that are not aggregated CER as this information may not impact their consumption and generation decisions. May not be material enough to incentivise participation.
2. Reduce costs for market ancillary services, NSCAS and system restart and interventions	Shares the benefit of avoided market costs with the traders who provide the services enabling these cost reductions.	Widespread exemptions and reductions of these cost recovery mechanisms may result in an unfair allocation of costs to Market Participants who cannot participate in Scheduled Lite. May not incentivise participation of price-responsive resources that are not aggregated CER, as they may not have interest to provide these services. May not be material enough to incentivise participation.
3. Direct payment	Helps offset the costs incurred when participating. Can be structured to ensure that participants receive an incentive to provide visibility where and when AEMO	May require higher market fees from Market Participants that cannot participate in Scheduled Lite to fund the visibility service payments.

INCENTIVE MECHANISM	ADVANTAGES	DISADVANTAGES
	values for this information is highest. May be attractive to a broad range of price-responsive resources.	
4. Link eligibility to provide contingency FCAS to participation in Schedule Lite	Strong encouragement for participation by parties with the capability to adhere to the requirements of the Visibility Mode.	May not attract the desired level of participation due to the relatively low number of parties providing contingency FCAS. May act as a barrier to small-scale and CER participation in contingency FCAS markets as it will be a requirement to access these markets that they can already access.
5. Mandatory participation for all traders with specified characteristics	Likely to result in the greatest level of participation. Avoids the need for payments, changes to cost recovery frameworks or restrictions on access to other markets. Could provide a consistent framework for participation with large scale generation.	Enforcing compliance with the requirement to participate may be challenging because of the inherent lack of visibility and dispersion of price-responsive resources. Difficulty in setting a consistent threshold definition across the types of price-responsive resources (for example size). May limit plans and services to customers as there will be higher regulatory and compliance costs for traders.

Source: AEMO, Rule change request - Scheduled Lite Mechanism in the National Electricity Market, p 114-115

QUESTION 3: VISIBILITY MECHANISM - ENCOURAGEMENT TO PARTICIPATE

1. What are your views on the incentive mechanisms outlined in Table 3.1?
2. Are there any alternative incentives the Commission should consider?
3. Should mandatory participation in the visibility mode be considered?
   a. If so, what types of traders/ resources should be required to participate and what criteria (for example size in a region) or circumstances (observed behaviour or performance) could the requirement to participate be based on?

3.2.2 To what extent would visibility mode address the problems identified?

The Commission would like to understand if the visibility mode would improve the efficiency in the five outcome areas, set out in section 2.3. There may be potential benefits across all of these objectives. However, given the voluntary nature of the mode, it is difficult to determine as the level of participation would be a crucial factor. An initial assessment against these objectives is provided below:

- **Improve the efficiency of dispatch costs** — the potential benefit is that AEMO would be more aware of the intentions of price-responsive resources participating. However, as AEMO would not amend dispatch targets using the indicative bids, it would likely not improve the costs of dispatching.
- **More efficient wholesale spot prices** — the potential benefit is that AEMO would publish a price-adjusted demand curve using the indicative bids. It is not clear that publishing internally inconsistent data (a dispatch price not informed by voluntary visibility compared to a price-adjusted demand curve) will improve efficiency.
- **More efficient security of supply** — the potential benefit of visibility is that it could reduce the level of FCAS required as the actions of price-responsive resources will be known and AEMO may be less conservative in its actions.
- **More efficient reliability** — the potential benefit of visibility is that it could improve the predictions of the reserve situation and reduce the amount of investment duplication. However, as the response is not certain it cannot be relied upon to maintain a reliable system.
- **More efficient operation of networks** — the potential benefit is that visibility mode could assist distributors in tracking the operation of assets on their network. This information would also feed into distribution and transmission network planning reports. Line ratings and constraints are still conservative as the response can not be relied upon.

AEMO stated that visibility mode may be useful to assist traders to understand what is required to participate in central dispatch processes without having to comply with dispatch instructions. Aggregators that are not vertically integrated retailers, and large users, in particular, may not have the experience or capabilities to participate in dispatch initially. While the mode may not fully achieve the outcomes, it may assist in improving traders' capabilities to ensure that dispatch mode can operate successfully.

QUESTION 4: ASSESSMENT OF VISIBILITY MODE

1. Do you think visibility mode would be effective as designed? If not, what improvements or amendments would you suggest and why?
2. Do you agree with the Commission's initial assessment of visibility mode's ability to achieve the outcomes identified?
3. If we progress with this mode, what should the Commission consider in terms of implementation of this mode?
4. Is visibility mode needed as a stepping stone to the dispatch mode?

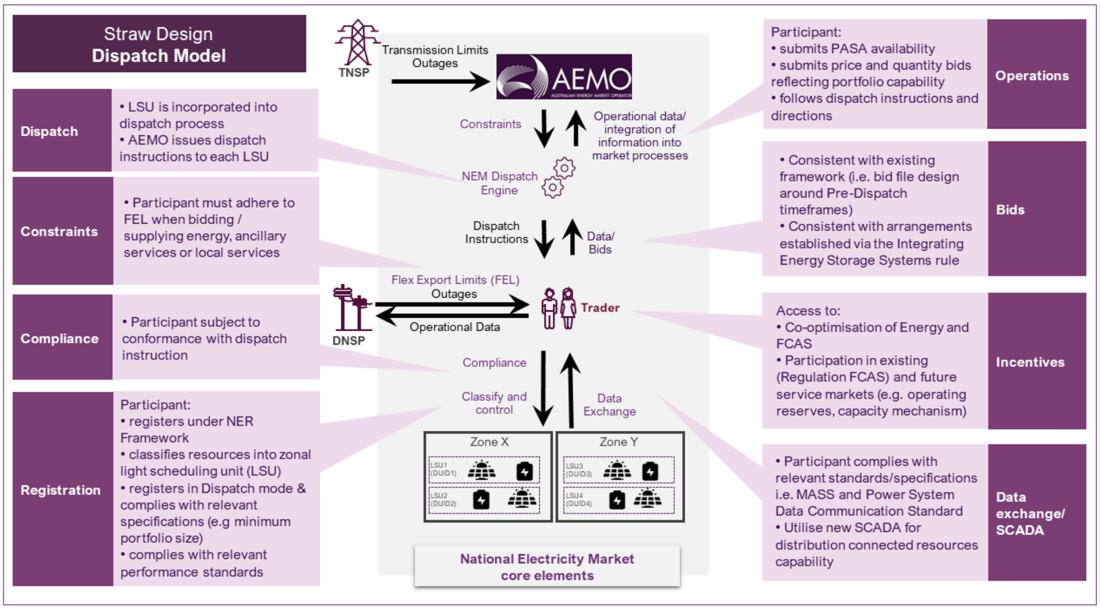
3.3 Dispatch mode

AEMO's proposed dispatch mode aims to encourage price-responsive resources to actively participate in the central dispatch process.[49] AEMO notes that having sufficient levels of resources that can be dispatched — comprising controllability, firmness and flexibility — are essential requirements for the operation of the power system.

Figure 3.3 provides a high-level overview of the key elements of this design.

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

Figure 3.3: AEMO straw design of Dispatch mode



Source: AEMO, Rule change request - Scheduled Lite Mechanism in the National Electricity Market, p 77.

3.3.1 What are the incentives to participate?

The Commission recognises that there are incentives and disincentives to participating in the proposed arrangements.

Incentives for participation

AEMO states the following incentives for participation in the Dispatch Mode could be considered:[50]

- the ability to schedule resources
- the ability to co-optimise energy and FCAS
- the eligibility to provide regulation FCAS, and
- the ability to access other services such as operating reserves, capacity certificates or primary frequency response (PFR).

The Commission notes that new frequency performance payment arrangements will commence in the NEM from 8 June 2025. Under the frequency performance payment process, a non-scheduled market participant would need to install appropriate metering and register their eligible units with AEMO in order to obtain an individual frequency contribution factor for individual frequency performance measurement and payment. This process would align with and support the AEMO's proposed rule change request.

50 AEMO, Rule change request -Scheduled Lite Mechanism in the National Electricity Market, p 16.

The Commission considers that participation in the Dispatch Mode may be further incentivised for sufficiently large traders by the ability to influence the wholesale market price. This could occur if these resources were marginal and set the dispatch price. We note that a similar mechanism to formalise demand-side participation in New Zealand identified the ability to set the clearing price in the dispatch market as the main benefit for participation.[51]

Disincentives for participating also exist

The rule change request identifies the costs and risks imposed on participants as relevant considerations for the incentive to opt-in to the Dispatch Mode.[52] These additional participation costs, such as the development of operating and monitoring systems and the coordination of geographically dispersed units, effectively raise the operating costs for traders. In addition, AEMO also identifies compliance arrangements, such as conformance with dispatch instructions, as a potential barrier to participation.[53]

The Commission considers the increase in operating costs to participate and the compliance cost of adhering to dispatch instructions as the two most material disincentives for participation in the Dispatch Mode.

Additional disincentives that may restrict participation include:

- a preference by retailers to not participate in the mode due to the similar magnitude of available benefit streams and the less strict compliance arrangements of their current arrangements, relative to the Dispatch Mode; and
- vertically integrated traders with relatively larger generation resources than retail load may not be incentivised to reduce the spot price.

We may need to also consider if currently, or through this mechanism, there is potential and incentive for traders to exercise market power. This could occur if a participant had sufficient resources to flexibly use price-responsive resources to increase the price that they receive for their portfolio of generation. Alternatively, it could be related to the extra information included in market systems (from a higher proportion of resources being scheduled) providing opportunities for parties with market power to exercise that power effectively.

While incentive-based processes may be preferable, such arrangements also need to be effective. Therefore, in recognition of the importance of price-responsive resources in delivering future reliability, security, emissions reduction and efficient pricing, we are seeking stakeholder feedback on the criteria or circumstances that may justify required participation, and who that could apply to.

51 New Zealand Electricity Authority, Remaining elements of real-time pricing, Consultation paper, March 2019, pp 18-19.

52 AEMO, Rule change request -Scheduled Lite Mechanism in the National Electricity Market, p 133-134.

53 AEMO, Rule change request - Scheduled Lite Mechanism in the National Electricity Market, p 132.

QUESTION 5: DISPATCH MODE — INCENTIVES TO PARTICIPATE

1. Do you think dispatch mode would be effective as designed? If not what improvements or amendments would you suggest and why?
2. What costs would traders incur to participate in dispatch mode?
3. Is access to the wholesale electricity market and other markets (for example regulation FCAS and PFR) sufficient incentive to participate in dispatch mode?
4. Are there other factors that would encourage or discourage participation in the dispatch mode?
5. Should participation in the dispatch mode be required? If so, what types of traders/resources should be required to participate, against what criteria and in what circumstances?

3.3.2 To what extent would dispatch mode address the problems identified?

The Commission would like to understand if the dispatch mode would improve the efficiency of the five outcome areas set out section 2.3. There may be potential benefits across all of these objectives. However, given the voluntary nature of the mode, it is difficult to determine as the level of participation would be a crucial factor. An initial assessment against these objectives is provided below:

- **Improve the efficiency of dispatch costs** — the potential benefit is that traders would be bidding into the market, they would be optimised in dispatch processes and will receive dispatch instructions. As traders will need to comply with the dispatch instructions, this will provide confidence in an efficient outcome for the cost of dispatch.
- **More efficient wholesale spot prices** — the potential benefit is that by receiving bids from price-responsive resources, and including them in dispatch, spot prices will reflect the intentions of participants controlling them. To the extent these intentions are materially different to current forecasts these will drive improved accuracy of spot prices. For example, by taking into account the intentions of price-responsive load, price spikes may be avoided (as illustrated in Figure 2.4).
- **More efficient security or supply** — the potential benefit is that bidding information would better inform price and dispatch. Therefore, there would be less reliance on regulation and potentially contingency FCAS. This would reduce the need and cost of these services. Furthermore, as these resources could then also participate in regulation FCAS (which they can't currently do), it broadens the market for these services.
- **More efficient reliability** — the potential benefit is that demand forecasts will be improved. There will be better predictions of the reliability and reserve situation. This could result in reduced use of RERT and reduce the duplication of network and grid infrastructure.
- **More efficient operation of networks** — the potential benefit is that it could assist distributors in tracking the operation of assets on their network. This information would also feed into distribution and transmission networks planning reports. It would result in reduced need for conservative line ratings or constraints.

QUESTION 6: ASSESSMENT OF DISPATCH MODE

1. Do you agree with the Commission's initial assessment of the ability of dispatch mode to address the outcomes identified?
2. If we progress dispatch mode, what does the Commission need to consider in terms of implementation of this mode?

3.4 Other issues raised by the proposal

There are two issues not specifically related to visibility and dispatch modes on which the Commission seeks stakeholder feedback:

- **Principles-based rule**

  AEMO has proposed a principles-based approach to rule drafting. Under this approach the rules will establish the main framework for the mechanism (for example, the classification of LSUs), but the technical details (for example, performance requirements) will be considered by AEMO when it develops the associated guidelines and procedures.

  The Commission notes that while the details would not be included in the final rule (if made), AEMO included significant details on how the mechanism would operate to assist stakeholders in understanding its intent. This information is explored in appendix B. If the Commission makes a final rule to introduce mechanisms similar to the visibility and dispatch modes proposed, we will need to satisfy ourselves that this approach is best. This consideration will be guided by a number of factors, such as which entity has the expertise to determine and update such details and whether more prescriptive drafting is needed to provide certainty and clarity.[54]

- **Consequential retail rule amendments**

  AEMO notes that consequential changes to the National Energy Retail Rules (NERR) may be required.[55] The scheduled lite mechanism focuses on the relationship between the trader and the wholesale market. However, there is the prospect of needing to consider if any changes are required to the relationship between the customer and the trader (governed by the NERR, including the model terms and conditions for standard retail contracts in schedule 1) as a result of the introduction of a scheduled lite mechanism. For example, traders could be required to provide certain information to customers.

  We note that the *Unlocking the CER benefits through flexible trading* rule change and the AER consumer protections review are also considering the appropriate consumer framework and protections, which provide alternative avenues to address any issues that may arise.

54 See section 2.2 of the AEMC's rule drafting philosophy, 8 October 2020.

55 AEMO, Rule change request - Scheduled Lite Mechanism, p 36.

The Commission is likely to most closely focus on these issues once we have determined if we are progressing with the mechanism proposed by AEMO, or a similar mechanism. However, we welcome views by stakeholders at this early stage.

QUESTION 7: OTHER ISSUES RAISED IN RELATION TO THE SCHEDULED LITE MECHANISM

1. Do you consider that the proposed mechanism (or a similar mechanism) should be introduced through a principles-based framework, with the details considered through AEMO's procedures and guidelines?
2. Do you consider that the proposed mechanism (or a similar mechanism) requires changes to the NERR to protect consumers?

4 ARE THERE MORE EFFICIENT WAYS TO INTEGRATE PRICE-RESPONSIVE RESOURCES?

This chapter seeks feedback on other potential methods to address the issues identified in chapter 2.

In particular, we focus here on:

- amending current arrangements, and
- other mechanisms used internationally.

While we identify each of these below, we note that some might not solve all the issues but could in part address some problems identified. Combining a few changes together could be a viable alternative to AEMO's proposed mechanism. We would like to understand from stakeholders if there are other mechanisms that could be considered, as an alternative, or to improve AEMO's proposed solution.

4.1 Could the current arrangements be amended?

There are a number of current arrangements, such as scheduled load, WDRM and the small generation aggregator (SGA) framework, that exist but are not available to or suitable for all price-responsive resources. The Commission is asking for stakeholder views on:

- whether existing rules could be amended to include a greater proportion of price-responsive resources in scheduling, or
- if the proposal from AEMO better meets the needs of participants with these types of price-responsive resources.

The current mechanisms and the Commission's initial view on limitations with using these arrangements is outlined below. Further explanation of these arrangements is outlined in appendix A.

4.1.1 Scheduled load requirements are onerous and are not designed for aggregators

Scheduled loads (such as pumped hydro) bid in how their energy consumption will change at certain price points and are required to consume electricity in line with the dispatch instructions issued by AEMO.[56] The scheduled load category was primarily designed for large industrial loads. This category has strict conformance obligations and is only available at a single connection point, therefore it may not be suited for aggregations of price-responsive load.

The take-up of this arrangement has been limited. Amending these arrangements (for example by altering the conformance requirements or opening it up to aggregated resources) to suit a wider range of price-responsive resources may not suit the resources we want to include. In addition, we would need to consider the impact of any changes for the existing participants and the operation of the scheme.

56 NER clauses 2.3.4 (f)-(g) and 3.8.7.

4.1.2 WDRM currently excludes small customers

The WDRM was introduced in 2020 and allows price-responsive demand to be incorporated into central dispatch. The final design excludes small customers from being a qualifying load and participating in the mechanism. The reasons behind this decision were:[57]

- it was unlikely that the mechanism would be suited to participation of large numbers of small customers
- baselines may encourage inefficient behaviour by small customers
- the costs of including small customers would likely outweigh the benefits
- the energy-specific consumer protections framework does not currently extend to demand response provided through third parties.

We would need to consider the impact of any proposed changes for the existing participants and the operation of the scheme.

4.1.3 Amending the SGA framework

Participants in the SGA framework are not currently scheduled; they are not visible in the wholesale market. The SGA framework is designed to reduce the barriers to small generation being able to directly participate in the NEM, with the SGA having access to the NEM spot price without each small generating unit owner having to register with AEMO. Changing this framework to be scheduled could impact the existing participants in this category. We would need to consider the impact of any proposed changes for the existing participants and the operation of the scheme.

4.1.4 Improve forecasting arrangements

AEMO's existing forecasting processes include some price-responsive resources. This includes the DER register and the Demand Side Participation (DSP) information portal.[58] In preparing this rule change request, AEMO decided not to consider amendments to these as the current portal is designed for static data. AEMO notes that considerable changes to the interface of the portal would be required to make the DSP portal information more dynamic and current.[59] However, the Commission is interested to understand if visibility could be improved through amendments to these current processes.

4.2 Are there insights from mechanisms to include price-responsive resources internationally?

We commissioned research to understand how other countries incorporate price-responsive resources into their energy markets. The research focused on California, Texas, Great Britain, New Zealand, Western Australia and Northeast US. NERA's report is published with this consultation paper.

57 AEMO, National Electricity Amendment (Wholesale Demand Response Mechanism) Rule 2020, June 2020, p. 5

58 NER rules 3.7D and 3.7E.

59 AEMO, rule change request, p 20.

The research highlighted a range of mechanisms. The main finding is that most mechanisms focus on driving more demand response rather than integrating price responsive resources into the energy market. This purpose results in a different type of design, focused on encouraging uptake of these mechanisms rather than incorporating these responses into scheduling and market operations.

It is important to note that Australia is at the forefront of the uptake of price-responsive resources and the associated challenges.[60] When examining the lessons learned from other jurisdictions it is important to take into account the context in which they were developed.

Some interesting findings included:

- California and New Zealand make it easy to participate in their demand response mechanisms but have weak enforcement of performance, leading to high uptake (in California) but lower reliability.
- Western Australia and Texas impose high barriers to entry and stiff penalties for non-performance, probably limiting uptake but also ensuring reliability.
- Great Britain is in between, with onerous testing requirements but weaker performance incentives, so lower uptake and lower reliability.

There are a number of lessons from these case studies:

- More recently, there is a focus on schemes with low barriers to entry which encourage participation from smaller parties, for example Great Britain's Demand Flexibility Services and New Zealand's Dispatch Notification mechanism.
- Testing vs penalties:
  - Only Great Britain subjects price-responsive providers to ex ante testing procedures.
  - Western Australia and Texas penalise underperformance to the extent that a price-responsive resource provider would not want to offer an amount that it could not deliver.
- Some markets limit price-responsive resources only to participating in reserve/capacity/emergency markets, for example Western Australia and Great Britain.

The research indicated that there are limited mechanisms to draw on that have attempted to schedule price-responsive resources. However, they have been successful in eliciting demand response and providing operators with greater information. There may be merit in some elements of these schemes to address some elements of the issues we are trying to solve.

QUESTION 8: ARE THERE PREFERABLE ALTERNATIVE ARRANGEMENTS?

1. Are there any alternative solutions that you think would be preferable to AEMO's proposal and more aligned with the long-term interests of consumers? What are the costs and benefits of any proposed alternative arrangement?

60 Susanto, J, Navigating the energy mid-transition, 21 February 2022, The Winston Churchill Memorial Trust, p. 5, available here.

5 MAKING OUR DECISION

When considering a rule change proposal, the Commission considers a range of factors.

This chapter outlines:

- issues the Commission must take into account
- the proposed assessment framework
- decisions the Commission can make
- rule-making for the Northern Territory.

We would like your feedback on the proposed assessment framework.

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

The Commission may only make a rule if it is satisfied the rule will, or is likely to, contribute to the achievement of:

- the NEO, with respect to the proposed changes to the NER, and
- the NERO, with respect to any consequential changes to the NERR.

These are the decision-making frameworks that the Commission must apply

The NEO is:[61]

> 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.

The NERO is:[62]

> to promote efficient investment in, and efficient operation and use of, energy services for the long term interests of consumers of energy with respect to price, quality, safety, reliability and security of supply of energy.

The Commission must also, where relevant, satisfy itself that the rule is "compatible with the development and application of consumer protections for small customers, including (but not limited to) protections relating to hardship customers" (the consumer protections test).[63]

Where the consumer protections test is relevant in the making of a rule, the Commission must be satisfied that both the NERO test and the consumer protections test have been

61 Section 7 of the NEL. In May 2023, energy ministers approved amendments to the national energy laws to include an emissions reduction component in the energy objectives. The legislative process is currently in train and is expected to conclude in September 2023. While this paper reflects the current NEO and NERO, future publications on this rule change will adopt the new objectives after the law change takes effect.

62 Section 13 of the NERL.

63 Section 236(2)(b) of the NERL.

met.[64] If the Commission is satisfied that one test, but not the other, has been met, the rule cannot be made (noting that there may be some overlap in the application of the two tests).

There may be some overlap in the application of the two tests. For example, a rule that provides a new protection for small customers may also, but will not necessarily, promote the NERO.

5.2 We propose to assess the rule change using these five criteria

5.2.1 Our regulatory impact analysis methodology

Considering the NEO and NERO and the issues raised in the rule change request, the Commission proposes to assess this rule change request against the set of criteria outlined below. These assessment criteria reflect the key potential impacts – costs and benefits – of the rule change request. We consider these impacts within the framework of the NEO and NERO.

The Commission's regulatory impact analysis may use qualitative and/or quantitative methodologies. The depth of analysis will be commensurate with the potential impacts of the proposed rule change. We may refine the regulatory impact analysis methodology as this rule change progresses, including in response to stakeholder submissions.

Consistent with good regulatory practice, we also assess other viable policy options - including not making the proposed rule (a business-as-usual scenario) and making a more preferable rule - using the same set of assessment criteria and impact analysis methodology where feasible.

Considering the NEO and NERO and the issues raised in the rule change request, the Commission proposes to assess this rule change request against the set of criteria outlined below. These assessment criteria reflect the key potential impacts - costs and benefits - of the rule change request.

5.2.2 Our regulatory impact analysis methodology

Assessment criteria

- **Security and reliability** — would greater visibility and dispatchability of price-responsive resources promote a secure and reliable electricity system through more accurate forecasting and operation?
- **Concepts of efficiency**
  - Allocative efficiency — to what extent will increased visibility and integration of price-responsive resources in the scheduling process lead to efficient wholesale spot prices?
  - Productive efficiency — to what extent will increased visibility and integration of price-responsive resources in the scheduling process lead to efficient dispatch costs and investment in these resources?

64 That is, the legal tests set out in sections 236(1) and (2)(b) of the NERL.

    - Dynamic efficiency — to what extent will increased visibility and integration of price-responsive resources in the scheduling process lead to efficient investment in generation, storage and demand response over time?
- **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?
- **Flexibility** — would the solution be future-proof, resilient and able to accommodate market, technological, policy and other changes?
- **Decarbonisation** — would the solution efficiently contribute to the achievement of government targets for reducing Australia's greenhouse gas emissions? (Note that we will apply this criterion if and when the law changes to include emission reduction components in the NEO and NERO take effect.)

QUESTION 9: ASSESSMENT FRAMEWORK

1. Do you agree with the proposed assessment framework? Are there additional principles that the Commission should take into account or principles included here that are not relevant?

5.3 We have three options when making our decision

After using the assessment framework to consider the rule change request, the Commission may decide:

- to make the rule as proposed by AEMO[65]
- to make a rule that is different to the proposed rule (a more preferable rule), as discussed below, or
- not to make a rule.

The Commission may make a more preferable rule (which may be materially different to the proposed rule) if it is satisfied that, having regard to the issue or issues raised in the rule change request, the more preferable rule is likely to better contribute to the achievement of the NEO and NERO.[66]

65 AEMO rule change request, Scheduled Lite Mechanism, 10 January 2023.
66 Section 91A of the NEL and section 244 of the NERL.

5.4 We may make a different rule to apply in the Northern Territory

Parts of 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.[67]

The proposed rule may apply in the Northern Territory, as it amends provisions in NER Chapters 4A and 8 that apply in the Northern Territory.[68]

The Commission will therefore assess the proposed rule against additional elements required by Northern Territory legislation:

- *Should the NEO test include the Northern Territory electricity systems?* For this rule change request, the Commission will determine whether the reference to the "national electricity system" in the NEO includes the local electricity systems in the Northern Territory, or just the national electricity system, having regard to the nature, scope or operation of the proposed rule.[69]
- *Should the rule be different in the Northern Territory?* The Commission will consider whether a uniform or differential rule should apply to the Northern Territory, taking into account whether the different physical characteristics of the Northern Territory's network would affect the operation of the rule in such a way that a differential rule would better contribute to the NEO.[70]

The NERR do not apply in the Northern Territory.

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

68 Under the NT Act and its regulations, only certain parts of the NER have been adopted in the Northern Territory. The version of the NER that applies in the Northern Territory is available on the AEMC website at: https://energy-rules.aemc.gov.au/ntner.

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

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

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
BDU	Bi-directional unit
CER	Consumer Energy Resources
Commission	See AEMC
DAPR	Distributed annual planning report
DER	Distributed Energy Resources
DOE	Dynamic Operating Envelope
DMIS	Demand management incentive scheme
DNSP	Distribution Network Service Provider
DRSP	Demand Response Service Provider
DSP	Demand Side Participation
DUID	Dispatchable Unit Identifier
ESB	Energy Security Board
ESOO	Electricity Statement of Opportunities
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Services
FEL	Flexible Export Limits
GPS	Generator Performance Standard
GW	Gigawatt
GWh	Gigawatt hour
IRP	Integrated Resource Provider
ISP	Integrated System Plan
LOR	Lack of reserve
LRC	Low reserve condition
LSU	Light Scheduling Unit
MASS	Market Ancillary Services specification
MT PASA	Medium Term Projected Assessment of System Adequacy
MW	Megawatt
NECF	National Energy Customer Framework
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market 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 Meter Identifier
NSCAS	Network support and control ancillary services
PFR	Primary Frequency Response
Proponent	The proponent of the rule change request
PV	Photovoltaic
RERT	Reliability and Emergency Reserve Trader
RIT-D/T	Regulatory investment test Distribution / Transmission
RRO	Retailer reliability obligation
SGA	Small Generation Aggregator
SRA	Small Resource Aggregator
ST PASA	Short Term Projected Assessment of System Adequacy
TNSP	Transmission Network Service Provider
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
V2G	Vehicle to grid
WDRM	Wholesale Demand Response Mechanism
WDRU	Wholesale Demand response units

A APPENDIX - SERVICES AND CATEGORIES

Throughout the document we refer to a number of services and market categories that currently exist. This appendix provides an overview and background to these.

A.1 SRA/SGA

The Small Resource Aggregators (SRAs, currently called SGA) framework allows participants to aggregate small generating or small bi-directional units.[71] To participate each small generating unit or small bidirectional unit must have its own connection point and a NEM-compliant metering installation.[72]

A household with a battery behind a single connection point can not be classified as a small bidirectional unit and can not be aggregated with others by an SRA to participate as a non-scheduled wholesale participant.[73] This framework was established to allow the owners of small generating units to have the additional option of selling electricity from those units to an SRA instead of a Market Customer.

Some SRAs separate general household/business load from the responsive resource by using the embedded network framework to create a separate child connection point for the responsive resources. Under this arrangement, the child meter must be an on-market meter with no retail load. This allows the SRA to classify the second (separate or "child") connection point as a small resource connection point comprising either a small generating unit or small bi-directional unit and participate as a non-scheduled resource in the NEM.[74] Under this arrangement, the SRA creates a small generating or bi-directional unit that is non-scheduled and its operation is invisible to AEMO and the market.

A.2 WDRM

The WDRM was introduced in 2020 to allow price-responsive demand to be incorporated into central dispatch. The mechanism differs from scheduled load in that the responsive demand bids in its ability to reduce demand relative to its baseline consumption and receive payment for this response, at spot market prices, similar to generation. This allows AEMO to incorporate this price-responsive demand into central dispatch, where it may not have been otherwise captured.

Demand response service providers (DRSPs) are able to register qualifying loads as demand response units. For a load to be considered as a qualifying load it must:[75]

- exist at a single connection point

71 AEMO, Fact Sheet - NEM - Small Generation Aggregators v6, 2021, p. 1. The current framework covers small generating units. From 3 June 2024, it will include batteries of less than 5MW, called small bidirectional units, operated by Small Resource Aggregators, under the Integrating energy storage systems into the NEM rule change made on 2 December 2021.

72 AEMO, Fact Sheet - NEM - Small Generation Aggregators v6, 2021, available here.

73 This is because household consumption could not be considered as auxiliary load in the definition of a small resource connection point. The definition is available in the Integrating energy storage systems into the NEM final rule, schedule 6.

74 NER clause 2.2.8 and chapter 10 (definitions), as amended by the Integrating Storage rule.

75 NER clause 2.3.6.

- not be a small customer or scheduled load
- have appropriate metering equipment installed.

  Additionally, the DRSP must have the consent of the relevant customer, and AEMO must be reasonably satisfied that when a baseline methodology is applied to the load, it produces a baseline that satisfies the baseline methodology metrics.

From the criteria above, small customers are explicitly excluded from participating in WDRM. The Final Determination for the WDRM rule change noted the following reasons for not extending the mechanism to small customers:

- the mechanism set out in the final determination would be costly to extend to small customers
- small customers would be unlikely to capture any value from being able to participate in the mechanism
- there was difficulty in adequately addressing the application of energy-specific consumer protections to arrangements between small customers and DRSPs.[76]

The Commission considered that progressing regulatory reforms that facilitate the transition towards a two-sided market is the best approach to allow small customers to participate more actively in the market.[77] Further details on excluding small customers from the WDRM can be found in Chapter 5 of the Final determination.

A.3 Scheduled load

A scheduled load must comply with the requirements and obligations set out in the NER related to participation in the central dispatch process. This includes, but is not limited to, compliance with the false and misleading bidding and the information provision requirements needed to allow AEMO to prepare the ST PASA and MT PASA.

The rules for participating as a scheduled load do not place any restriction on the participation of smaller loads. However, the smaller price-responsive loads being explored in this paper are not likely to have the telemetry or control to comply with scheduling.[78] In addition to this, smaller price-responsive loads would face the same incentive issues that are outlined in chapter 3 and may not be incentivised to participate in scheduling.

A.4 Contingency FCAS

FCAS are procured by AEMO as market ancillary services through the NEMDE as part of the 5-minute dispatch process. Provided that a participant meets the technical requirements defined in AEMO's MASS, they can participate in the contingency FCAS markets.[79] This includes aggregations of households.[80]

76 The Commission noted a holistic review of consumer protections was required to consider consumer protections in non-traditional energy services and products, which included wholesale demand response.
AEMC, Wholesale demand response mechanism, Final determination, 11 June 2020, p. 31.

77 Final determination, Wholesale demand response mechanism, 11 June 2020, chapter 5.

78 Scheduled loads can be aggregated under NER clause 3.8.3, but must be connected at a single site.

79 AEMO Market Ancillary Services Specification (MASS), available here.

FCAS provide frequency responsive reserves that increase or decrease active power to dynamically stabilise supply and demand in the power system and control system frequency.[81] Contingency services (raise and lower) are used to provide balancing reserves to respond to larger deviations in power system frequency that are usually the result of contingency events such as the tripping of a large generator or load. These services are split up into three categories: fast, slow and delayed.[82]

Providers of FCAS are paid for the amount of FCAS in terms of dollars per megawatt enabled per hour. That is, providers receive a payment irrespective of whether the service is required to be delivered. Where the service is required to be delivered, the provider also receives payment for any energy associated with the provision of the service.

A.5 DNSP engagement with industry for non-network solutions

DNSPs are required to develop an industry engagement strategy which sets out the strategy for engaging with non-network providers and considering non-network options for addressing system limitations.[83]

The AER's demand management incentive scheme (DMIS) encourages distribution businesses to find lower cost solutions to investing in network solutions. The DMIS achieves this by providing financial incentives to DNSPs to undertake efficient expenditure on non-network options relating to demand management.[84] The demand management solutions currently applied by DNSPs in the DMIS can be grouped into three broad categories:

- Direct load control by DNSPs
- Customer demand response through incentive payment
- Use of temporary generation.[85]

The AER also provides incentives to DNSPs under the Demand Management Innovation Allowance (DMIA), to conduct research and investigation into innovative techniques for managing demand.[86] The DMIA also aims to develop industry knowledge of practical demand management projects and programs through the publication of annual project summary and expenditure reports. In 2017 the DMIA was replaced by the Demand Management Innovation Allowance Mechanism (DMIAM) for regulatory control periods commencing after 2017. [87]

80 NER clause 3.8.3 permits aggregation of loads to be treated as one ancillary service load for central dispatch. The loads must be connected within a single region and be operated by a single person.

81 AEMC, System services rule changes, Consultation paper, 2 July 2020, p. 105.

82 Fast services achieve target response within six seconds and sustain for 60 seconds. Slow services achieve target response with 60 seconds and sustain for five minutes. Delayed services achieve target response within five minutes and sustain for at least ten minutes.

83 NER rule 5.13.

84 NER clause 6.6.3.

85 AER, Decision, Demand Management Incentive Scheme (DMIS) payments for 2020–21 and 2021–22, May 2023, p. 1.

86 AER, Approval of Demand Management Innovation Allowance (DMIA) expenditures by Queensland and South Australian electricity distributors in 2019–20, April 2021, p. 5.

87 AER, Approval of Demand Management Innovation Allowance (DMIA) expenditures by Queensland and South Australian electricity distributors in 2019–20, April 2021, p. 5.

A.6 NSCAS

NSCAS are non-market ancillary services that may be procured by AEMO or TNSPs to maintain power system security and reliability and to maintain or increase the power transfer capability of the transmission network. AEMO is required to assess NSCAS needs in the NEM for the upcoming five-year period. When AEMO identifies an NSCAS gap, the NER give TNSPs the primary responsibility for having arrangements in place to address the gap. AEMO will be required to acquire NSCAS to ensure power system security and reliability only if the NSCAS gaps remain unmet after TNSP's attempt to procure services.[88]

88 Reliability Panel, 2021 Annual Market Performance Review, Final report, 28 April 2022, p 77.

B APPENDIX: DETAIL ON AEMO'S PROPOSED SOLUTION

This appendix provides further detail on the design of the visibility and dispatch modes.

B.1 Visibility mode

Three key features of visibility mode; participation requirements, data use and type and operations are set out below.

B.1.1 Participation requirements

The Rule change request outlines that traders must first be registered with AEMO under the NER participant registration framework. Depending on which resources are being classified for Scheduled Lite the trader could be registered as a Market customer, IRP or a Generator. This will leverage AEMO's existing system and processes for information and settlement flows.[89]

NMIs would be assigned to a zone on a sub-regional zonal basis, in line with the zonal load forecasting process AEMO is developing for the ST PASA replacement program.[90] This aggregation is expressed in Figure 3.1. There would be no minimum level of resource, either individually or multiple NMIs aggregated, to participate in the visibility mechanism. AEMO acknowledges that splitting eligible NMIs into zones may introduce additional cost and complexity for Scheduled Lite traders. Additionally, this zonal requirement may lead to customers in some zones being able to access other market value streams that have a volume requirement, such the 1MW contingency FCAS requirement, more quickly than customers in other zones.

AEMO has proposed the zonal requirement to prevent the need to disaggregate LSU bid information and forecasts to zonal level to align with the new zonal load forecasting approach. If NMIs are not classified in line with the zonal load forecasting model, the error introduced through the disaggregation of the LSU information could be material, creating risks to system security and undermining the benefits of the mechanism.

The request acknowledges that traders' operational capabilities may change over time and proposes an opt-out arrangement. This opt-out arrangement enables a trader to opt-in and opt out of the Visibility mode, rather than requiring 24/7 operational capability as is required for scheduled resources. Opting out of Visibility mode will correspond to traders having to perform less onerous functions.[91]

89 Please see Table 2 on page 89 of the rule change request for more information.

90 https://aemo.com.au/initiatives/trials-and-initiatives/st-pasa-replacement-project

91 AEMO, 2023, rule change request, appendix B: high level design, pg 48-49.

B.1.2 Data type and use

AEMO proposes that traders would provide standing data, real-time forecast and indicative bids for consumption and generation via an application programming interface.[92]

AEMO have identified a range of data would be required to participate[93]:

- Standing data: Such as the total capacity of the resources at each connection point (consumption and generation) and price-responsive capacity at each connection point (consumption and generation)
- Real time data or close to real time data: Including actual consumption, generation and energy stored, which would be provided by the trader for each LSU.
- Forecast capacity: This would involve the trader forecasting the LSUs consumption, generation and stored energy over the short term horizon.
- Indicative bids: These set out the indicative forecasts of the injections or withdrawals at different price points for each LSU.[94]

The revenue meter at the participating site would need to adhere to requirements in NER Chapter 7 (for small customers, this would typically mean a type 4 meter) and capable of recording data in five-minute intervals. If providing FCAS, the trader must comply with the metering requirements outlined in the MASS.

Project EDGE findings indicate that the required scheduled capabilities from distributed price-responsive resources can be developed progressively. This supports the need for visibility mode as a stepping-stone to dispatch, to develop robust understanding of market requirements for dispatchability.[95]

B.1.3 Operation

Bids

LSUs operating in Visibility mode will be required to provide information to indicate their price-responsive intentions. AEMO has proposed that the detail on the bid structure will be developed in the implementation stage, however, below shows an example of how a traders demand would be reflected through an indicative bid profile.

BOX 3: VISIBILITY MODE — INDICATIVE BID EXAMPLE

AEMO provided the following example that outlines how a traders' portfolio of price-responsive resources at a single LSU, show in Figure B.1, might look like.

92 AEMO, 2023, rule change request, pg 14

93 AEMO, 2023 rule change request, Appendix b high level design pg 38

94 For more information see Table 9 from AEMO's rule change request on page 105.

95 AEMO, Project EDGE, accessed 28 June. https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge

Figure B.1: Underlying responsive resources in a traders portfolio

Portfolio*			Assumptions	Intention	
Resource		Capacity (MW)		Market Price Range ($/MWh)	Action
Load	Air conditioning	30		>10,000	Reduce 15 MW of consumption
Load	Household bi-directional units		10 MW of the aggregation have a similar profile	Negative	Charge 10 MW
Neutral				0 to 2,000	No action
Generation				Above 2,000	Discharge 10 MW
Load			5 MW of the aggregation have a similar profile	Negative	Charge 5 MW
Neutral				0 to 4,000	No action
Generation		15		Above 4,000	Discharge 5 MW
Load	Pool pumps	10		>10,000	Reduce 3 MW of consumption
Generation	Rooftop PV	5		Negative	Turn off

Source: AEMO

This portfolio of resources would then be arranged by the trader into intentions of consumption and generation at different price points to define the indicative bid values, as shown in Figure B.2 below. This is in effect the aggregate of all the different resources that respond at different prices into a single bid.

Figure B.2: Aggregate responsive resources ordered into a bid

Market Price Range ($/MWh)	Air conditioning (MW)	Bi-directional units 10 MW profile (MW)	Bi-directional units 5 MW profile (MW)	Pool pumps (MW)	Rooftop PV	Intention to be reflected in the Bid*
Negative Prices	-30	-10	-5	-10	0	-55
0 to 2,000	-30	0	0	-10	5	-35
2,000 to 4,000	-30	10	0	-10	5	-25
4,000 to 10,000	-30	10	5	-10	5	-20
>10,000	-15	10	5	-7	5	-2

Source: AEMO

For the purposes of this example only price-responsive resources have been reflected in the bid. Where responsive and passive resources are located behind a single meter, the passive component would also need to be reflected in the bid.

Source: AEMO, rule change request, p. 106.

Through the implementation phase, AEMO considers that additional information could be included through this process, such as local services and an uncertainty indication.[96]

Dispatch

The indicative bid information provided by LSUs will be incorporated into AEMO's demand curve. This adjusted demand curve will use the pre-dispatch scheduling process to produce and publish a 'price adjusted' demand forecast.

The 'price adjusted' demand forecast represents an improved 'best estimate' on current demand forecasts, which do not include demand response and unscheduled generation. Scheduled lite participants and Market participants can utilise the 'price adjusted' demand

96 AEMO, rule change request, pp. 106-107.

forecast and estimates of demand response to support the efficient operation of their portfolio.[97]

Compliance

AEMO recognises that the form and nature of compliance arrangements have the potential to act as a significant barrier to participation.[98] However, AEMO notes that its important the compliance arrangements drive effective performance and reliable outcomes, to provide confidence that the integration of price response resources is benefiting the operation of the market.

Given these considerations, AEMO has proposed a relatively light-handed compliance arrangement for the Visibility model, with compliance being determined by AEMO from measuring the accuracy and consistency of information provided by a trader against a set of performance thresholds:[99]

- Forecast accuracy: an allowable variation between the actual consumption or generation and the indicative bid provided by the trader over a rolling period.
- Consistency of real-time information: real-time information submission must be provided.

Where a trader does not meet the performance thresholds, it would not be rewarded for participation in the mechanism, but would not be penalised. AEMO proposed that a trader would be suspended from participating in the Visibility model if it deviates materially from the performance thresholds.

> QUESTION 10: VISIBILITY MODEL — PARTICIPATION, DATA AND OPERATIONS
>
> 1. Would traders be readily able to participate and provide the data as proposed? What implementation considerations and costs would be required to participate?
> 2. Is there anything the Commission could do in designing the rule that would help to minimize the costs and maximise the benefits?

B.2 Dispatch mode

Three key features of dispatch mode; participation requirements, data use and type and operations are set out below.

B.2.1 Participation requirements

The participation requirements for the Dispatch model is similar to Visibility model, described in appendix B.1.1, with the following high-level differences:

97 AEMO, rule change request, p. 181.

98 AEMO, rule change request, p. 114.

99 AEMO, rule change request, p. 115.

- The minimum size of a DUID would have a threshold of 5MW. This was proposed to support the operational requirements with preparing scheduling inputs for LSUs, such as bids.[100]
- LSUs would have to eventually need to adhere to an equivalent to a Generator Performance Standard (GPS) for LSUs. These would be established by AEMO in the implementation of the rule change.[101]

It is proposed that traders would be able to manage their participation by opting out of Dispatch mode (unavailable) at times when they do not expect to be able to meet the Dispatch mode requirements.[102]

B.2.2 Data type and use

The standing data required for dispatch mode is the same for visibility mode, with the following data streams required:

- Telemetry: Telemetry data would consist of the aggregated instantaneous period ending measurement of active power flow at NMI and actual generation, load and energy stored.[103]
- Bids: Would represent an offer of both generation and load for the LSU in each trading interval. Bids may contain 20 price bands per LSU.
- Availability forecast: This forecast represents the available capacity of generation, load and storage in an Aggregator portfolio.
- FELs: These distribution level limits, however arrangements for sharing of FELs is out of scope for the Scheduled Lite high-level design. Traders would have to adhere to FELs when bidding/ supplying energy, ancillary services or local services.

AEMO outlines that it has not specified all the data requirements associated with participation in the Dispatch model. AEMO proposes that further consultation with industry during the implementation of Scheduled Lite will determine the specification of these data requirements.

B.2.3 Operations

Bids

LSU operating in Dispatch mode will be able to be dispatched for energy by submitting energy bids (20 price and volume bands). Subject to meeting eligibility requirements outlined in the MASS, LSUs would be able to participate in all FCAS markets in a manner analogous with a scheduled resource, allowing up to 10 bid bands for each service.[104]

Dispatch

100 The aggregated portfolio would need to be in the same zone are, as described in appendix B.1.1.

101 Traders would still have to ensure the resources in each LSU meet the relevant technical standards, such as, voltage control and fault ride through capabilities. As well as complying with distribution connection agreements.

102 AEMO, rule change request, p. 133.

103 This information would be provided in line with the requirements for distributed resources defined in the power system communication standard.

104 AEMO, rule change request, pp. 125-126.

LSUs operating in Dispatch mode will be incorporated into the existing NEM dispatch process. The dispatch process takes in bids from all scheduled resources, co-optimises the energy and FCAS dispatch within NEMDE, and produces dispatch instructions for a dispatchable unit identifier (DUID). The trader of an aggregated portfolio will receive dispatch instructions per DUID, and will then need to manage its portfolio and control its resources to respond to the dispatch instruction. Where a trader is participating in FCAS, NEMDE will co-optimise energy and FCAS for LSUs in the same method as scheduled resources.[105]

Compliance

Similar to the compliance arrangements for visibility mode, AEMO recognises that compliance arrangements have been consistently raised as a potential barrier to participation. Based on performance in the EDGE trials and feedback from traders, AEMO understands that aggregated portfolios of distributed resources are generally able to conform to dispatch instructions. The project EDGE findings show that dispatch conformance improved over time, indicating that scheduled capabilities can be developed progressively and supporting a stepping-stone approach.[106]

AEMO has proposed consistent arrangements for the conformance of WDRM participants, with these conformance arrangements being reviewed at a later date to ensure they are fit for purpose.[107] The compliance arrangements for the WDRM are lighter in nature than those for other scheduled resources, and they are not monitored as part of real-time operations. At a high-level the conformance rules for WDRM and those proposed for Scheduled lite dispatch mode are:

- The first trading interval of its dispatch is not assessed
- There is an interval error of + or – 6 MW before non-conformance is flagged
- An error band equivalent to + or – 50% of their dispatch targets across a settlement day is assessed
- Three or more instances (effectively days where non-conformance is flagged) of non-conformance must be flagged before the unit is declared non-conforming.

AEMO suggests that traders could self-manage their compliance by opting out of Dispatch mode during periods where they are not confident of complying with dispatch targets. The request proposes that the conformance arrangements for LSUs will be reviewed as the mechanism develops to ensure that:

- They are fit for purpose, particularly if Dispatch units become a material share of scheduled resources, and
- The avoidance of any limits on the volume Dispatch units (and wholesale demand response units (WDRU)) that may be permitted in a region due to the lighter compliance arrangements.

105 For more information on this process please see page 126 of the rule change request.

106 AEMO, Project EDGE, accessed 28 June 2023. https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/der-demonstrations/project-edge

107 AEMO, rule change request, p. 133.

QUESTION 11: DISPATCH MODEL — PARTICIPATION, DATA AND OPERATIONS

1. Could price-responsive resources comply with the operational and data requirements? If not:
    a. How difficult would it be to change your systems to comply with the requirement outlined above?
    b. Does this depend on what resource is participating?
2. Do the proposed compliance arrangements strike an appropriate balance between the reliability of the response and the barrier to participation?